RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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

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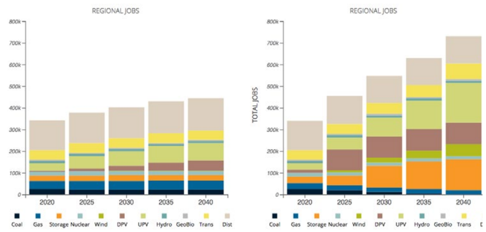
Study: Southeast RTO Would Cut Costs, Emissions

By Rich Heidorn Jr.

Utilities in seven Southeastern states could cut their electric rates by more than a quarter and reduce greenhouse gas emissions by almost half by joining an organized wholesale market, according to a *study* by a clean energy think tank.

The study by *Energy Innovation Policy & Technology* compared the use of utility-specific integrated resource plans (IRPs) with an RTO Scenario, which chose the most economical resources, optimized dispatch to minimize cost, and co-optimized transmission and distribution planning and regionwide reserve sharing. The results were based on a combined production-cost and capacity-expansion model of the electric power system in Alabama, Florida, Georgia, North Carolina, South Carolina, Tennessee and the non-MISO portion of Mississippi.



Energy Innovation's online data explorer allows readers to review the impact of a Southeast RTO on the region's fuel mix, emissions, jobs and costs by region and state. *Click here.* | *Energy Innovation*

It projected cumulative economic savings of about $384 billion for the RTO Scenario compared to the IRP Scenario. By 2040, researchers say, retail rates would average

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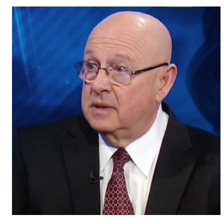
NJ Senate Exploring Exit from PJM

By Michael Yoder

New Jersey legislators are considering a bill that would require the Board of Public Utilities to study the implications of withdrawing from PJM and either going it alone or joining NYISO.



NJ Sen. Bob Smith (D) | *NJ Senate*

Members of the New Jersey Senate Environment and Energy Committee voted unanimously during a hearing Aug. 17 to advance the bill, sponsored by committee Chair Bob Smith (D), with a series of amendments to the full Senate (*S2804*).

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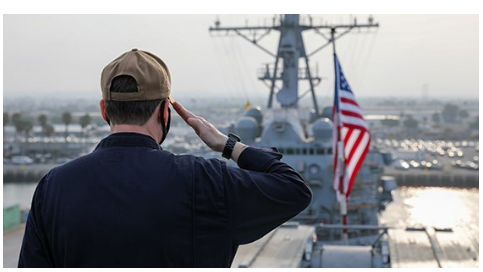
CAISO Provides More Details on Blackouts

Explains Conservation Efforts in Letter to Governor

By Hudson Sangree

The three California organizations that oversee electricity responded to a request by Gov. Gavin Newsom to explain why the state had two days of rolling blackouts on Aug. 14 and 15 and would have had more if not for statewide conservation efforts.

"We agree that the power outages experienced by Californians this week are unacceptable and unbefitting of our state and the people we serve," CAISO, the Public Utilities Commission and the Energy Commission told Newsom in a joint *letter* last week. "We understand the critical importance of providing reliable energy to Californians at all times, but especially now, as the state faces a prolonged heat wave and continues to deal with impacts from the COVID-19 pandemic."



Disconnecting Navy ships from shore power helped CAISO avoid more blackouts. | *U.S. Navy*

The organizations operate independently but coordinate efforts to supply the state with electricity. CAISO operates the transmission grid. The CPUC regulates investor-owned utilities and orders procurement. The CEC forecasts demand, among other functions.

"We are working closely as joint energy organizations to understand exactly why these events occurred," they said.

The tone of shared responsibility differed from CAISO's initially blaming the CPUC for failing to procure sufficient energy despite warnings of capacity shortfalls starting this summer. (See *CAISO Blames Blackouts on Inadequate Resources, CPUC*.)

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Memphis Moves Closer to Breaking from TVA (p.20)

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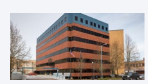

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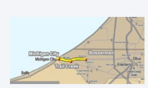
Coastal States Seek Balance on OSW (p.15)



MISO Board Primed for 1st Major Interregional Project (p.17)

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Study: Southeast RTO Would Cut Costs, Emissions

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2.5 cents/kWh, or 29% less than current costs (adjusted for inflation).

The researchers also project a 37% reduction in carbon emissions compared with 2018 levels, and a 46% reduction compared to the IRP Scenario. They said the RTO Scenario would create 285,000 more jobs than the IRP Scenario, thanks to the construction of 62 GW of solar, 41 GW of onshore wind and 46 GW of battery storage.

The study is the latest of several recent initiatives looking at the Southeast's alternatives to the current vertically integrated model. Legislators in the Carolinas have proposed studies on creating an RTO and about 20 utilities and cooperatives in the region — including Duke Energy, Southern Co. and Tennessee Valley Authority — are discussing a voluntary 15-minute energy market, the Southeast Energy Exchange Market (SEEM). (See *Southeast Utilities Talking Regional Market*.)

Last September, Santee Cooper's largest customer joined PJM in the wake of the South Carolina-owned utility's abandoned plans to build a new unit at the V.C. Summer nuclear plant. (See *South Carolina Power Cooperative Joins PJM*.)

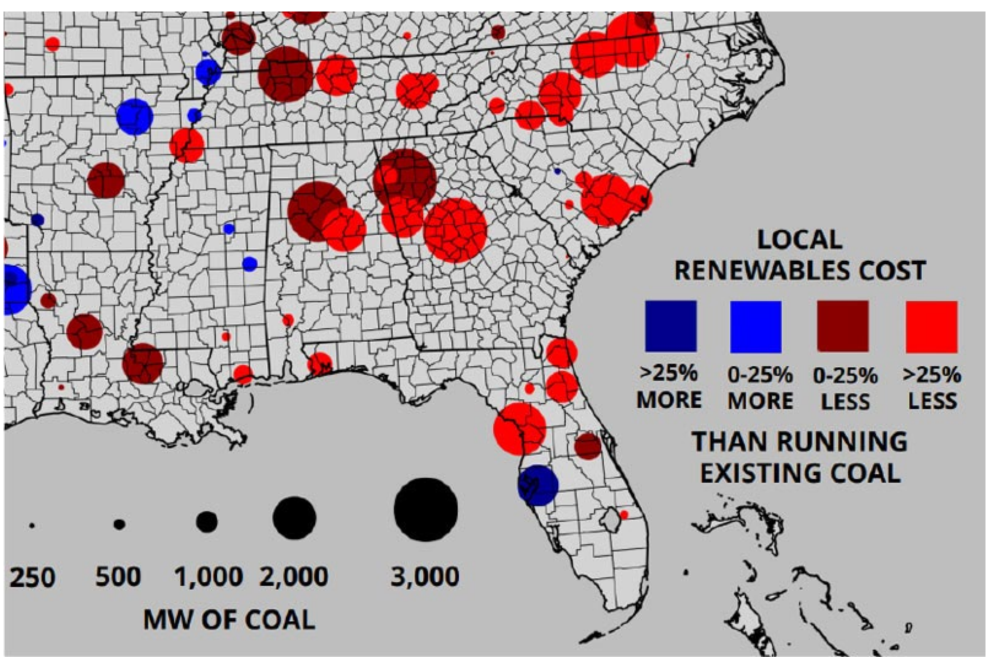
"Despite the fact that new renewable energy and battery storage resources are the least-cost forms of generating electricity, the Southeast region is largely beholden to monopoly utilities that rely on existing coal fleets and new gas-fired power plants to meet consumer electricity needs," Energy Innovation said. "Policymakers considering a regional market or state-level competitive procurement should be encouraged by this analysis to keep pressing in legislative and regulatory forums. State stakeholders where utilities block competitive reforms now have new quantitative findings to challenge the assumption that the way utilities have traditionally done business is in the public's best interest."

Asked to respond to the findings, Duke spokeswoman Erin Culbert said Monday that the utility has "been advancing a clean energy transition for more than a decade" and doesn't "need to wait for an RTO."

"Duke Energy customers already enjoy many of the benefits RTOs claim to bring because of our large geographic size and generation diversity," she added. "The energy market we're considering would enhance that and better integrate renewables at a much lower cost than an RTO."

TVA spokesman Scott Fiedler said, "It would be inappropriate to comment on a study that we did not participate in, nor had the opportunity to review the underlying data used to develop the conclusions."

Officials of Southern Co. did not immediately respond to requests for comment.



About 92% of the Southeast's coal capacity was uneconomic compared to local wind or solar as of 2018, according to Energy Innovation Policy & Technology. By 2025, all coal will be uneconomic, the group says. | *Energy Innovation Policy & Technology*

Region Resistant to Renewables

Energy Innovation describes itself as a nonprofit energy and environmental policy firm funded by foundations and philanthropic donors that support decarbonization and climate policy. For the study, Energy Innovation used a model from *Vibrant Clean Energy*, which was supported by funding from the Hewlett Foundation.

The firm says ratepayers in the Southeast are missing out on the economies of a regional market because their monopoly utilities plan their grids and generation needs independently from their neighbors — including subsidiaries of the same holding companies — and discourage competition by imposing wheeling charges on imports. "Largely insulated from meaningful forms of competition, Southeastern utilities have been among the slowest to embrace clean electricity resources, even as resource costs have fallen precipitously in recent years," it said.

About 92% of the region's coal capacity was uneconomic compared to local wind or solar as of 2018, the researchers said. "By 2025, that number grows to 100%."

Michael O'Boyle, Energy Innovation | *Energy Innovation Policy & Technology*

The study did not include any carbon constraints and also did not imply a market design. "This is not PJM's RTO. This is not MISO's RTO. It is a technical optimization of costs based on one single regional grid," coauthor Michael O'Boyle, Energy Innovation's electricity policy director, said during a press briefing Friday.

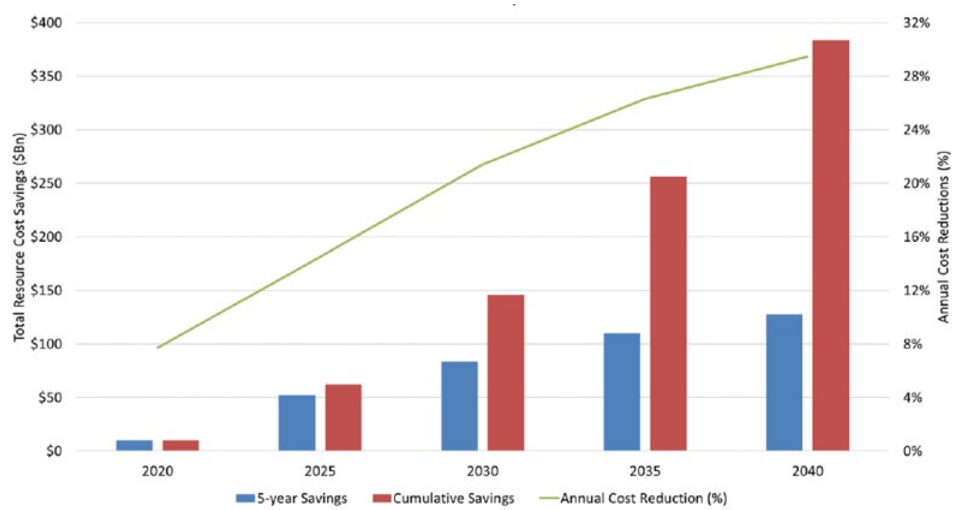
The RTO model used a single planning reserve margin for the region, eliminating the inefficiencies of serving loads on a state-by-state basis in the IRP Scenario. It did not optimize transmission and dispatch with neighboring PJM and MISO, however.

Energy Innovation said its model represented the maximum benefits of competition, noting

FERC/Federal News

that some markets allow vertically integrated monopolies to continue recovering costs of generation from captive customers. "RTOs today also face structural and political barriers to transmission development and fair cost allocation, distribution optimization, and clean or distributed energy resource participation," the researchers noted.

The researchers also acknowledged that the IRP Scenario is likely to differ from utilities' ultimate 2040 mix because the 10- to 15-year IRPs are updated periodically. "Hopefully, as utilities and their regulators catch up to the reality that clean electricity is less expensive than the status quo, it is reasonable to assume the inefficiencies won't be quite as stark as the modeling implies," they said. "Nevertheless, we model the current IRPs to demonstrate how current utility plans ... open up customers to financial risk from potential stranded assets."



The study projects cumulative savings of about $384 billion for the RTO Scenario compared to the IRP Scenario. By 2040, researchers say, retail rates would average 2.5 cents/kWh (29%) less than current costs (adjusted for inflation). | *Energy Innovation Policy & Technology*

Additional Scenarios

The study also looked at two additional possibilities, including the Economic IRP Scenario, which includes a cost-optimal resource mix — reflecting competitive procurement within existing monopoly service territories — but without the co-optimized transmission and reliability planning in the RTO Scenario. It would save $298 billion through 2040 compared to the IRP Scenario — about three-quarters of the savings of the RTO Scenario.

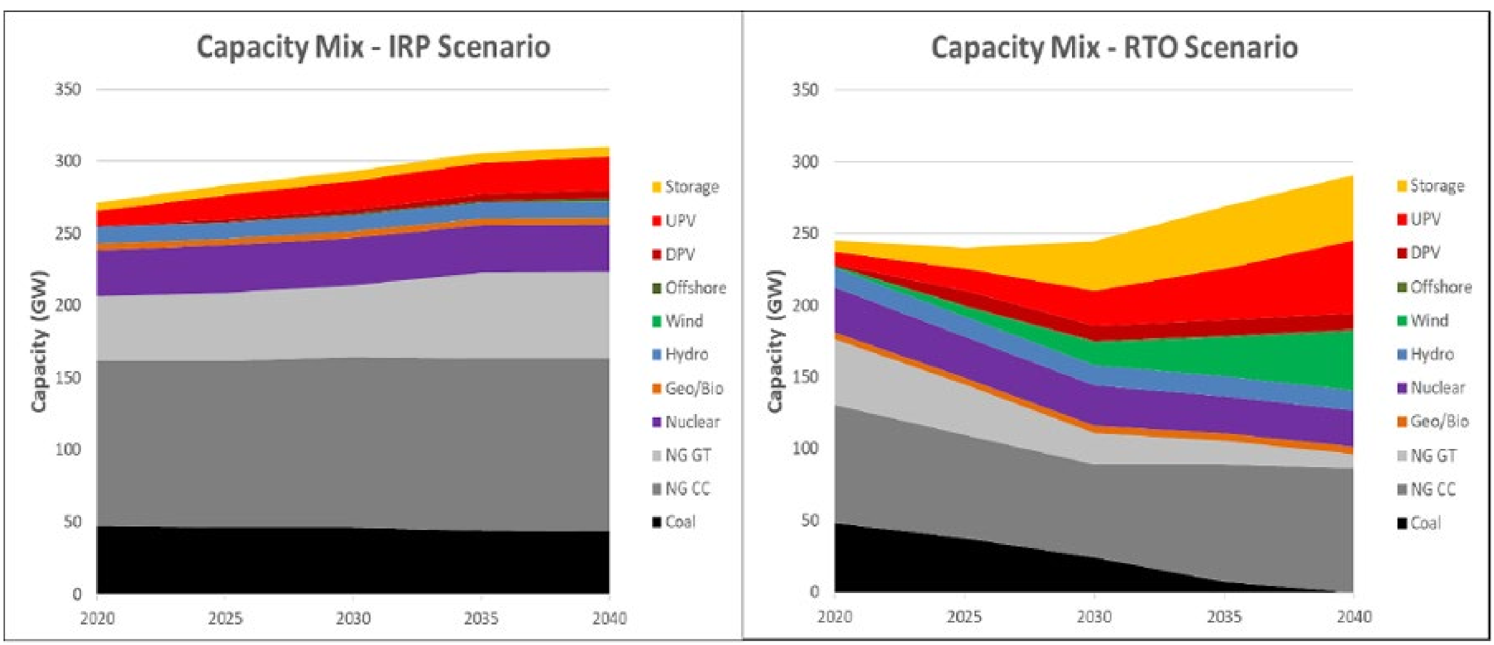
"This recognizes the reality that full regionalization may be politically infeasible in the near to medium term but shows that a majority of the cost savings can still be achieved by subjecting utility procurement plans and existing generators to market competition," Energy Innovation said.

The RTO with Nuclear Scenario adds to the RTO Scenario the assumption that all existing nuclear plants extend their licenses and remain operational through 2040, regardless of cost-competitiveness — essentially assuming they would be kept in service through subsidies such as those enacted in Illinois, New Jersey and New York.

It would save about $375 billion through 2040, $9 billion less than the RTO Scenario but with a 41% cut in emissions below 2018 levels compared to a 37% drop in the RTO Scenario.

Reduced Reserve Margins

The RTO Scenario rationalizes transmission planning to reduce congestion and allow load pockets access to cheaper generation. It realizes about 10% of cumulative savings ($38 billion) from co-optimized distribution system planning that uses behind-the-meter genera-



A Southeastern RTO would add increasing amounts of renewable generation, replacing coal and natural gas selected under utility integrated resource plans, according to Energy Innovation Policy & Technology. | *Energy Innovation Policy & Technology*

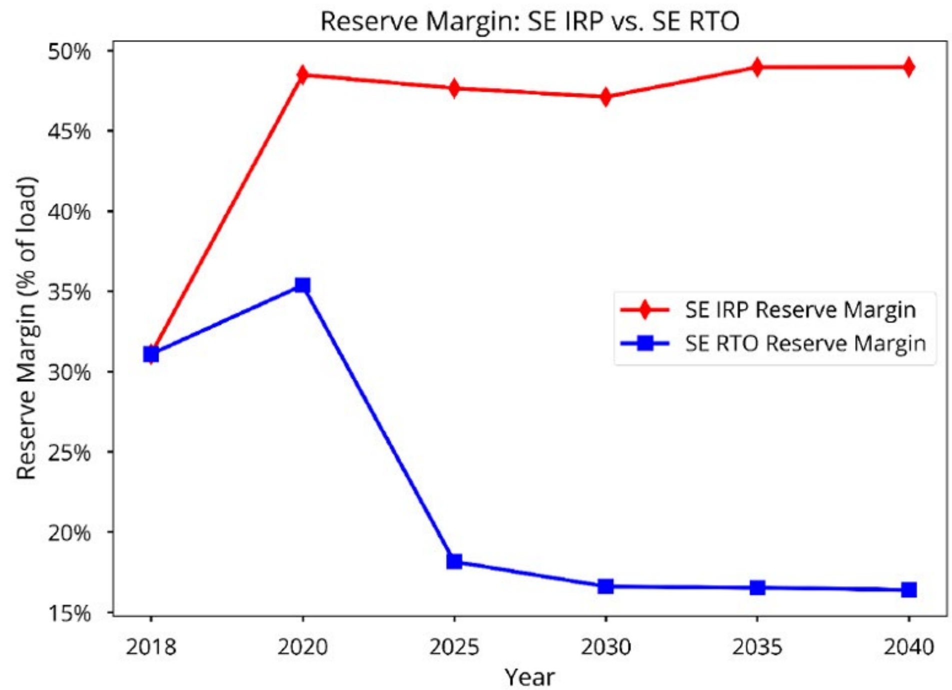
FERC/Federal News

tion and storage when it reduces total system costs.

"This co-optimization of bulk and small-scale resources helps reduce peak load in the RTO Scenario 11.8% below the IRP Scenario, creating savings from generation all the way down to distribution," the study says. "Realizing these savings goes beyond reforming the market structure for the bulk power system and likely requires regulatory incentives at the distribution level to coordinate with a central RTO."

The researchers say the IRP Scenario would result in a reserve margin over 40%, resulting in more jobs in unnecessary coal and gas plants. "Utility IRPs in aggregate are redundant and excessive on their own, but when taking a regional view where significant efficiencies could be obtained by sharing reserves, the waste becomes more apparent," the researchers said. "Utilities are rushing to build new gas generation that increases their earnings while planning to hold onto uneconomic coal generation for decades longer than economics would dictate."

The RTO Scenario assumes a 16% reserve margin in 2040. Nevertheless, Energy Innovation says, "By 2040, the RTO Scenario leads to an additional 408,000 jobs in the sector, compared to just 122,000 new jobs in the IRP Scenario, a net of 285,000 jobs."



The IRP Scenario would result in a reserve margin over 40% by 2040, according to the study, far above the 16% margin for the RTO Scenario. | *Energy Innovation Policy & Technology*

Emissions

The study notes that Duke and Southern Co., which represent 45% of retail sales in the Southeast, have pledged net-zero company emissions by 2050. But it says, "a competitive market with no carbon policy does a better job of reducing emissions than Duke and Southern's efforts."

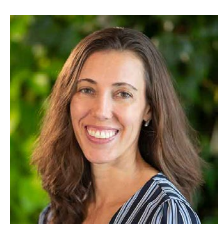
"Vertically integrated utilities' incentives to maintain and earn on existing infrastructure conflicts with both customer wellbeing and environmental goals. … Regional transmission and operational approaches are more effective at integrating high shares of renewable electricity, and Duke and Southern hamper their own efforts to decarbonize at least cost by resisting regionalization efforts," the researchers said.

The IRP Scenario adds little renewable generation or battery storage, while the RTO Scenario adds large amounts of wind and solar PV, including distributed PV, and utility-scale and distributed storage, with most gas peakers retiring by 2040.

Most generation would remain fossil fuel by 2040 under the IRP Scenario. "In the IRP Scenario, there is almost no wind generation, and solar PV provides just 4% of annual generation. In contrast, wind and solar provide 22% of generation in the RTO Scenario; when aggregated with nuclear (20%), geothermal/bioenergy (5%) and hydropower (4%), 51% of the Southeast fleet is zero-carbon by 2040."

Other pollutants, including NO_X, SO_2 and PM2.5, also would be reduced by the elimination of coal-fired generation, the researchers say.

Endorsement



Bryn Baker, Renewable Energy Buyers Alliance | *REBA*

During the press briefing Friday, the *Renewable Energy Buyers Alliance*, which represents more than 120 major corporate purchasers, endorsed the call for regionalization and suggested the region's competitiveness is at stake.

"More and more businesses are setting [clean energy] goals. They're making decisions about siting and expanding facilities based on access to renewable energy," said Bryn Baker, REBA's director of policy innovation. "Right now, many parts of the country, including the Southeast, their only option is often a green tariff through the existing utility, which can often be limited."

Baker said full regionalization offers savings "10-fold higher than anything that's being contemplated now" in the region, including SEEM.

"There are so many details that need to be filled out that it is a little bit premature to say, 'the SEEM is x.' We just don't know exactly what it's going to be," O'Boyle said. "There doesn't appear to be an agreement to use transmission without those wheeling charges, so … unless there's an open transmission agreement, there's still going to be unnecessary costs and a lack of optimization across the region."

Duke's Culbert said the SEEM would be much cheaper and faster to create than an RTO, "meaning energy customers in the Southeast would see real benefits much sooner."

"Participating in that would not prevent any of the companies from participating in an RTO in the future. From our perspective, we don't see RTOs as the right solution for Duke Energy customers in the Carolinas at this time. We're currently in the phase of engaging with stakeholders on SEEM and are working through their questions and feedback as we continue to formulate the concept." ■

Are California Utilities Ready for Fire Season?

'We are ready,' PG&E President Says

By Hudson Sangree

Lightning started most of the major wildfires now ravaging parts of California, but the fall season, when utility equipment tends to start fires, is coming fast.

Regulators and reliability coordinators want utilities to be ready, especially with regard to public safety power shutoffs (PSPS) to prevent fires ignited by electrical equipment.

On Thursday, WECC held the third and final webinar of its August workshops on wildfires in the West. It focused on vegetation management, following earlier sessions on weather monitoring and a high-level overview of wildfire preparedness. (See *WECC Tackles Wildfires as Reliability Threat*.)

CPUC President Marybel Batjer | *CPUC*

The week before, the California Public Utilities Commission hosted sessions to hear from the state's three big investor-owned utilities about plans for the upcoming fire season. Commission President Marybel Batjer singled out Pacific Gas and Electric, the state's largest utility, for the harshest criticism.

After two years of catastrophic wildfires in 2017 and 2018, PG&E blacked out 2 million people across large swaths of the state to prevent fires in 2019, while its website crashed and communication faltered. Even so, its equipment started another major blaze, the Kincade Fire in Sonoma County, state investigators determined.

Amid the COVID-19 pandemic, families are depending on electricity more than ever while working and learning from home, Batjer said. PG&E and other utilities must treat PSPS as a measure of last resort and keep them as brief and targeted as possible, making sure residents are safe and local officials are well informed, she said.

"This is what we saw PG&E unable to adequately execute on last year," Batjer said. "PG&E's haphazardly implemented PSPS events of last fall cannot be repeated."

"We need to understand from PG&E, 'Are you ready?'" she said.

Michael Lewis, interim president of PG&E, told her, "We are ready.

Interim PG&E President Michael Lewis | *PG&E*

"It is our intent not only to meet your expectations but to exceed them this year," Lewis said.

PG&E has been conducting PSPS drills this summer with the aim to keep the events "smaller, shorter, smarter," he said. The utility plans to reduce customer impacts by one-third. If current measures had been in place last year, nearly 300,000 fewer customers would have been blacked out, he said.

This year, with CPUC approval, the utility placed diesel generators at numerous substations so areas of its system can "stay energized without grid support," Lewis said. It installed 800 weather stations and 220 high-definition cameras for greater "situational awareness," he said. And it established the goal of restoring power within 12 daylight hours — a 50% reduction from last year — after a dangerous weather system has passed, including by using equipment that can scan power lines at night for faults.

PG&E created dedicated teams to work with "critical customers" such as hospitals and COVID-19 testing centers, he said. Low-income customers who rely on medical equipment, known as medical-baseline customers, are being provided with 3,000 batteries and solar panels to charge the units, PG&E told the commission.

IOUs Outline Efforts

Southern California Edison reported similar efforts to WECC and the CPUC.

Tom Brady, senior manager of emergency response at SCE, told WECC earlier this month that the utility had installed 650 miles of insulated wire in areas at high risk of fire.

SCE also placed 1,200 fuses and remote-controlled sectionalizing devices on its system to interrupt power more quickly and prevent ignitions. Sectioning off its grid also allows SCE to limit the extent of PSPS used to keep electrical equipment from starting fires during dry, windy conditions.

"We're able to minimalize, sectionalize and isolate the smallest footprint possible so that we're not interrupting a lot of customers," Brady said.

San Diego Gas & Electric, a state leader in fire prevention, told the CPUC it was using sectionalizing devices, microgrids and grid-hardening techniques, including undergrounding wires, to prevent fires. Public outreach and providing generators to medical-baseline customers and mobile home parks are part of its efforts, CEO Caroline Winn told the commission.

SDG&E has been trying to improve its prevention efforts every year since 2007, when massive wildfires swept San Diego County, she said. The IOU was the first in California to use power shutoffs as a fire-prevention tool, followed by SCE and now PG&E. The weather conditions that once only plagued Southern California have moved north in recent years.

In past years, catastrophic fires sparked by the IOUs' equipment mainly occurred in October and November. This year will be a major test of the IOUs' efforts to prevent destructive blazes without widespread, prolonged blackouts.

"We share the commitment of Gov. [Gavin] Newsom, of our legislative leaders and all of our CPUC commissioners to ensure that the public safety power shutoffs are conducted responsibly and only as a last resort to prevent catastrophic wildfires," Winn said. "We're also mindful, as you mentioned Commissioner Batjer, of the current COVID-19 pandemic and the impact of power shutoffs to our customers who are spending more and more time at home working and learning." ■

| *Cal Fire*

CAISO Provides More Details on Blackouts

Explains Conservation Efforts in Letter to Governor

Continued from page 1

Leaders of the three organizations said their staffs would need more time to fully analyze the causes of the blackouts, but they provided Newsom with their initial findings. The letter was signed by CAISO CEO Steve Berberich, CPUC President Marybel Batjer and CEC Chair David Hochschild.

Demand on Aug. 14-15 was high, peaking at approximately 47 GW and 45 GW respectively, they said, "but not above similar hot days in prior years. Given this, our organizations will need to conduct a deep dive into how we ensure sufficient electric supply and will make modifications to our reliability rules to make sure reliability resources can be available to address unexpected grid conditions." (See *CAISO: Blackouts May Continue, Calls Emergency Meetings*.)

The state's "heavy reliance" on imports was one obvious factor in the blackouts, the leaders told Newsom.

The heat wave that engulfed the West in triple-digit temperatures dried up imports that weren't secured by long-term contracts, CAISO said. It struggled to meet peak demand during the late afternoon and evening hours and would have ordered additional days of rolling blackouts if conservation efforts hadn't cut demand by 2,000 to 3,000 MW each day and the state hadn't secured more megawatts. (See *'Last Challenging Night' for CAISO, Governor Hopes*.)

Conservation, More MWs

The organizations provided additional details on those efforts in the letter to Newsom.

The CEC coordinated with data centers in Silicon Valley to move approximately 100 MW of load to on-site backup generation, the letter said. It worked with the U.S. Navy and Marine Corps to "disconnect 22 ships from shore power, move a submarine base to backup generators and activate several microgrid facilities resulting in approximately 23.5 MW of load reduction."

The state Department of Water Resources and the Metropolitan Water District of Southern California shifted 80 MW of hydroelectric generation to peak demand times. The department and the U.S. Bureau of Reclamation made changes in pumping schedules that secured another 72 MW. And San Francisco maximized output at its Hetch Hetchy hydroelectric facilities to generate an additional 150 MW during peak demand periods.

CAISO and the CPUC have both warned of more severe shortfalls going forward as fossil fuel plants and the state's last nuclear power generating station retire. The state's switch to solar and wind resources isn't to blame for the shortfall, but far greater storage is needed to meet "net-peak" demand after the sun sets, CAISO and the CPUC said recently. (See *CAISO, CPUC Warn of 'Reliability Emergency'*.)

To avoid shortfalls in the coming summers, "forecasts and planning reserves need to better account for the fact that climate change will mean more heat storms and more volatile imports, and that our changing electricity system may need larger reserves," the organizations wrote.

The CEC is holding *sessions* Wednesday to help forecast demand through 2030, with the recent shortfalls part of that discussion. ■

BPA Reinstates COVID-19 Restrictions

By Robert Mullin

The Bonneville Power Administration has pulled back into a more cautious operational posture in response to the COVID-19 pandemic after relaxing restrictions in June, agency officials said last week.

The return to a "Response Level 3" posture (from Response Level 2-A) comes just two months after BPA lifted restrictions enough to resume work on some maintenance and construction projects. That move aligned with the reopening of Pacific Northwest economies following stay-at-home orders issued by state governments in March.

Now the federal power marketing administration says it is "standing down" on any nonessential transmission or generation projects.

"We're deferring all maintenance and construction projects that are not tied to life safety or reliability," Nadine Coseo, BPA senior financial analyst, told listeners during a quarterly business review (QBR) workshop Wednesday.

Coseo said the change in posture was driven by agency metrics that consider the region's caseload of positive COVID-19 tests. Those metrics are showing "small clusters popping up around our territory, especially where the construction crews have been performing their work," she said. "We determined it was in the best interest for Bonneville to see if the metrics will either flatten or decline again before resuming our former phase."

BPA on Aug. 18 assured its customer base of publicly owned utilities that its crews will continue to respond to outages and other emergencies. It will also keep focusing on enabling office staff to telecommute in order to "reduce the concentration of employees in any one location and continue meeting business requirements."

The agency decided to resume a more restrictive pandemic posture one day after a Aug. 11 QBR call in which it explained that its third-quarter projections show it earning $152 million in net revenues for fiscal year 2020, which ends next month. That estimate puts BPA well above a second-quarter "baseline" case prediction of $110 million and a second-quarter pandemic "bad case" figure of $44 million. It also represents a steep rise from the agency's rate case target of $12 million for 2020. (See *BPA Poised to Weather COVID Impact*.)

| © RTO Insider

BPA explained that while reduced expenses account for some of the expected increase in net revenues, the greatest boost stems from increased net operating income — largely the product of higher profits from secondary sales of surplus energy.

Steve Gaube, a financial analyst with BPA's power generation division, confirmed that the revenue boost was more the result of high market prices than increased sales volume during what has been an average water year for the region's hydroelectric producers.

"We did see considerably higher Northwest regional prices, particularly in winter," Gaube said, adding that BPA expects this month to yield another rise in secondary sales because of high temperatures in the West.

BPA staff also clarified that the agency discontinued use of a separate pandemic "bad case" because it was equipped to factor pandemic effects into its general third-quarter forecast.

But staff also noted the third-quarter projections don't consider the impact of BPA's retreat into Response Level 3, which generates uncertainty around how the renewed delay in capital projects could move some costs into the agency's expense accounts and reduce the net revenue figure.

Addressing capital projects related to transmission, BPA accountant Kevin Bernards said the third-quarter projections "have kind of shown optimism" about 2020 capital budgets.

"However, the recent decision to return to a more restrictive posture will negatively impact this forecast," Bernards said. "At this point, it's still really too early to know the impacts, but this decision will definitely increase the risk that BPA will need to write off a portion of the indirect costs to expense. We're going to continue to monitor these impacts and just track what the impacts on the capital execution side will look like."

But BPA's generation side still foresees no capital project write-offs for this fiscal year despite delays caused by March's stay-at-home orders, according to Scott Eggimann, a lead accountant.

"I would say the message around this is really we're in a wait-and-see mode," Coseo said. "It's just too early to tell, and we will know more as the year progresses." ■

CAISO/West News

Oregon PUC Looks to Modernize Direct Access

By Robert Mullin

Oregon regulators are grappling with how to modernize the state's customer-choice electricity program to accommodate a rapidly changing energy landscape that's being reshaped by decarbonization policies across the West.

The Oregon Public Utility Commission last year opened an investigation (UM 2024) into the state's 20-year-old long-term direct-access programs, which give large energy consumers the ability to obtain electricity service outside the regulated cost-of-service regime. The commission is now seeking how to shape the inquiry.

The state legislature authorized the PUC to implement direct access as part of a raft of provisions in *SB 978*, a 1998 law intended to equip the commission with authority to implement programs that could address investor-owned utility greenhouse gas emissions, encourage the development of a regional electricity market and create retail choice options for nonresidential customers.

Oregon's two main IOUs, Portland General Electric (PGE) and PacifiCorp, function as gatekeepers for the programs, providing larger consumers with a yearly process for applying to opt out of regulated service in order to enroll in either a utility-run, market-based program, or contract with a third-party direct-access electricity service supplier (ESS). Similar to the process in other Western states, opting in to direct access carries certain "transition" costs for customers that ensure utilities reduce their exposure to stranded costs for providing regulated service, including meeting resource adequacy requirements. Those costs ultimately fall to the larger pool of cost-of-service customers.

Oregon Public Utility Commission headquarters in Salem, Ore. | *Oregon Secretary of State*

Evolutionary Need

UM 2024 comes in response to a June 2019 *petition* from the Alliance of Western Energy Consumers (*AWEC*), whose membership represents companies with 160 facilities (that employ 170,000 workers) comprising both direct-access and cost-of-service customers, according to the organization.

In seeking the investigation, AWEC's petition cited "significant disputes" over the programs in recent years, including those related to whether the state should further expand or restrict the programs and whether the programs have benefited or harmed cost-of-service customers. AWEC also noted that PGE's direct-access program — what it called the only one "that has successfully contributed to the development of a competitive market in Oregon" — is nearing its 300-MW cap, making it soon unavailable for customers.

Oregon PUC Commissioner Letha Tawney | *Oregon PUC*

"My goal, when I think about this docket, is to sort of see how and where this customer-choice option needs to adapt to the current and likely future of the system — the policy, the regulation, the markets and technology that are all evolving alongside a customer-choice program that we set and have tinkered around the edges with but not fundamentally grappled with for two decades," Commissioner Letha Tawney said during a Thursday workshop on the issue.

The PUC is proposing that its line of investigation address four sets of questions:

- Does the direct-access law currently raise concerns about unwarranted cost-shifting "or other relevant harms to the public interest?" Would expansion of the programs in size and reach create additional "concerns related to unwarranted cost-shifting or other relevant harms to the public interest?"

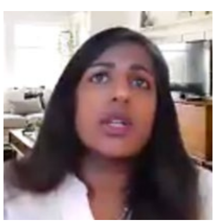
CAISO/West News

- Can program design mitigate unwarranted cost-shifting or other relevant harms? "What mechanisms should be used; how should such mechanisms be structured; and what are the legal or practical barriers to implementing them?"
- "With such mechanisms in place, are unwarranted cost-shifting or other relevant harms to the public interest mitigated to the degree that the commission should expand access to direct-access programs?"
- What evidence has been presented or could be presented in the docket (or a future one) to show that existence of cost-shifting and whether it would occur under an expansion of the program, and whether mitigation would be effective at preventing cost-shifting?

"I think our task here is in no small measure updating direct access and this particular kind of customer choice to where the world is today and the realities that are unfolding before us. … We talk a lot about existing cost-shifting, but I worry about the future," Tawney said.

From Cost-shifting to Risk-shifting

In *comments* filed ahead of the workshop, PGE asked the commission to consider the future potential for future "risk-shifting" in addition to historical concerns around cost-shifting.


Nidhi Thakar, PGE | *Oregon PUC*

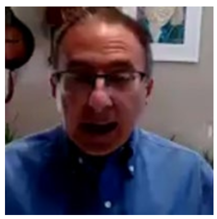
Elaborating in the workshop, PGE Director of Strategy Nidhi Thakar offered an example of risk-shifting: the fact that IOUs must serve as "*de facto*" energy providers of last resort in cases when an ESS fails financially, foisting its customers back on the utilities.

"We just want to call out again that we really see a distinction between the terms 'cost-shifting' and 'risk-shifting,'" Thakar said during the workshop. "There are ... going to be risks that are quantifiable. We really do believe that there are risks that are going to be harder to quantify, which to the extent that they can be quantified, those numbers could continually be changing.

"The markets are constantly evolving and changing at a rapid pace in the West, and I think it's important that there is some breathing room from the regulatory standpoint to readjust what some of these pricing mechanisms may look like that may potentially come out of this discussion."


Etta Lockey, PacifiCorp | *Oregon PUC*

Etta Lockey, PacifiCorp vice president of regulation, seconded PGE's take: "We don't want to get hung up on not being able to take action now because a particular risk can't be fully quantifiable or there's not full evidence of an unintended consequence that is likely to happen in the future."


Carl Fink, Blue Planet Energy Law | *Oregon PUC*

Speaking for the Northwest & Intermountain Power Producers Coalition, which represents ESSes, attorney Carl Fink rebuffed the notion that the PUC's proceeding should examine potential future risks for the IOUs.

"I don't really believe that's within the scope of what we can be doing here, nor do I think it's appropriate to really be looking at some of the opportunity costs that may or may not occur to the extent that utilities lose market share," Fink said.


Oregon PUC Chair Megan Decker | *Oregon PUC*

PUC Chair Megan Decker clarified her own thoughts about how to address potential opportunity costs for IOUs that could lose market share while still needing to maintain resource adequacy in their service territories.

"When I'm talking about that opportunity cost around meeting a flexible load in the grid, I'm very open to how that load comes to the table and participates. I think there's a need, and I have an interest in how the ESSes might participate in that flexible future," Decker said.

Fink also advocated for further expansion of direct access.

"We do want to stress that, to the extent the commission is looking back at how we should be doing direct access, we always need to start with the statute, as we say in every one of our pleadings," Fink said. "The statute puts requirements on the commission. It doesn't ask the commission to decide whether direct access is supposed to be OK; it says you shall ensure direct access. And it says it needs to be direct access for all customers."

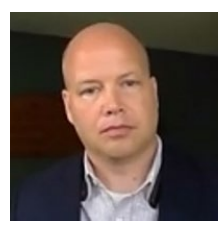
Tawney expressed concerned that, under the current structure, "a sort of wall comes down" after an electricity customer converts to direct access, cutting it off from the mechanisms in the regulated sector, "even though these customers have some of the most flexible and most interesting — and most capable — on-site resources that might help us through our transition to a clean-energy, high-renewables-based grid."

"There is a lot to be said for policy stability, but that means we need to set out boundaries or structures that will be resilient for how this future unfolds in the next decade, and that really requires thinking about the unexpected and setting up policies and structures that will manage those changes effectively," Tawney said.


Tyler Pepple, Davison Van Cleve | *Oregon PUC*

Tyler Pepple, the attorney who filed the petition on AWEC's behalf, asked whether the PUC would proceed under the presumption that direct access is in fact in the public interest.

"Is that the intention there, that we're sort of assuming that direct access is in the public interest because it's required by statute, or do you think that it's important for the parties to present evidence on the benefits of direct access and whether that would be helpful?" Pepple asked.


Oregon PUC Commissioner Mark Thompson | *Oregon PUC*

Commissioner Mark Thompson said he didn't think the PUC is being asked to consider whether direct access is in the public interest because state law has already established the program.

"I guess where I think the public interest question enters into it for us is with respect to how do we implement the statute's guidance that we're supposed to protect against unwarranted cost-shifting; and I do think the statute clearly contemplates us having a role there to put potential limits or guidelines on how that program is implemented," Thompson said. ■

ERCOT News

ERCOT: Transmission Constraints an Emerging Issue

Grid Operator Raising Awareness of Long-term Issues

By Tom Kleckner

Renewable energy's proliferation has played a key role in helping ERCOT meet demand, but it is also beginning to cause transmission constraints that are likely to increase during the next five years.

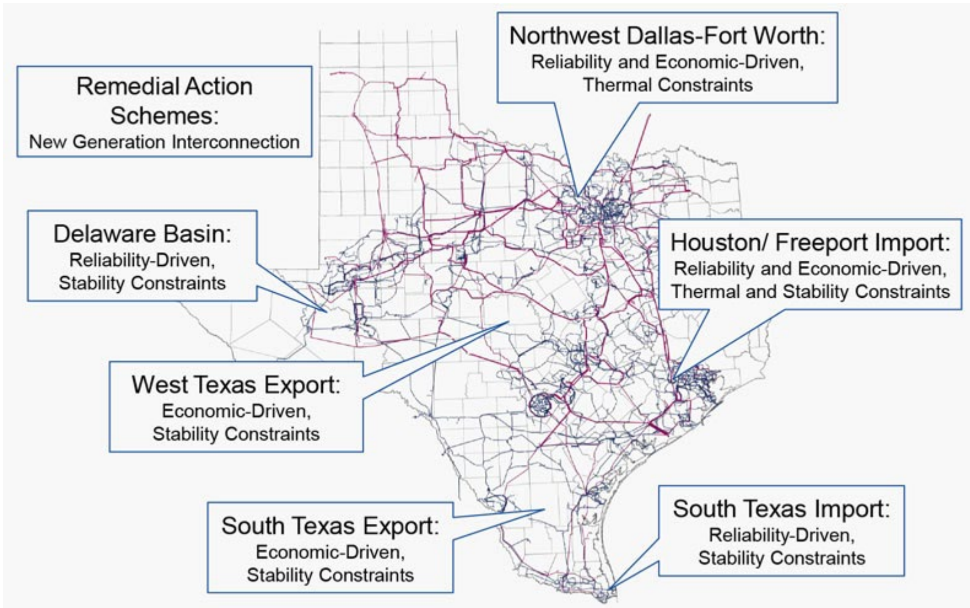
Staff are previewing what they say are necessary future conversations. They say that while planning studies have not shown that transmission constraints will hamper resource adequacy in the near term, they will pose an increasing challenge requiring more training, detailed models and more powerful software.

The problem is that new resources are being sited farther away from urban load centers, taking advantage of Texas' ample wind and solar potential. This shift from traditional, large fossil-fired plants near load centers to smaller renewable resources on the farthest reaches of the ERCOT system has led to the stability challenges.

"Every year, we're seeing generation getting a little further from load. That's our underlying issue," said Woody Rickerson, ERCOT's vice president of grid planning and operations. "It's inherently harder to serve load on the edge of the system, where it's not networked deeply into the system."

Rickerson told ERCOT's Board of Directors during its Aug. 11 meeting that most new generation projects are inverter-based resources. These resources are added to the planning models six months to two years ahead of their commercial operation date, but transmission

Jeff Billo, ERCOT | © *RTO Insider*



ERCOT's transmission-constrained areas | *ERCOT*

upgrades resolving congestion can take up to six years to complete.

Planning studies beyond 2022 don't include wind or solar projects, Rickerson said, "because the development time frame puts them inside the 2023 timeline."

"The planning process will result in some lag and congestion," he said.

Jeff Billo, ERCOT's senior manager of transmission planning, said the grid operator's "generator-friendly" interconnection process has also played a role. Beginning with the *Competitive Renewable Energy Zone* (CREZ) initiative — which resulted in 3,500 miles of transmission facilities in 2013, freeing up 18.5 GW of West Texas wind energy — the grid operator's stakeholders have set up processes designed to quickly add generation to the grid.

"Most developers I talk to prefer the ERCOT way, with the firm transmission rights and being able to get interconnected in less than two years, versus other [regions], where I hear anecdotally it can take six to seven years," Billo said. "We really needed to build some amount of transmission that was appropriate for new generation."

Not surprisingly, ERCOT has identified its West Texas zone, home to most of the state's wind resources, as one of five geographical areas where it expects emerging reliability and/or economic issues. Reliability issues are driven by load growth, and economic issues are typically driven by generation growth.

Rickerson said 28 GW of renewable generation is expected to be connected in West Texas, far beyond CREZ's plans. Stability limitations are expected to lead to high levels of congestion on West Texas exports, he said, but ERCOT is studying the region's congestion solutions in its 2020 Regional Transmission Plan.

Far West Texas is also home to the oil-rich Permian Basin's Delaware Basin, the fastest growing load in Texas. The region's annual peak load has grown by more than 10% since 2010, compared to the ERCOT's systemwide growth rate of about 1.5% during the same time frame.

Staff analyzed the Delaware Basin and has identified a five-stage roadmap of transmission upgrades to continue meeting the oil and gas load.

"If you are moving power across a longer distance, you'll have more marginal losses and reactive losses. With the inverter controls, you're pushing a lot of power on your circuit … and getting stability challenges," Billo said. "Going forward, stability is going to be more limiting than thermal issues. That's just the way our generation fleet is evolving.

"Because we have that generation-friendly

ERCOT News

environment, we can wait until the last minute [for developers] to turn in their data or make a commitment," he said. "We don't have a lot of lead time to know where the generation constraints are through this process. We've seen the system is evolving to where we see more and more stability constraints on the system, but the stability studies take time."

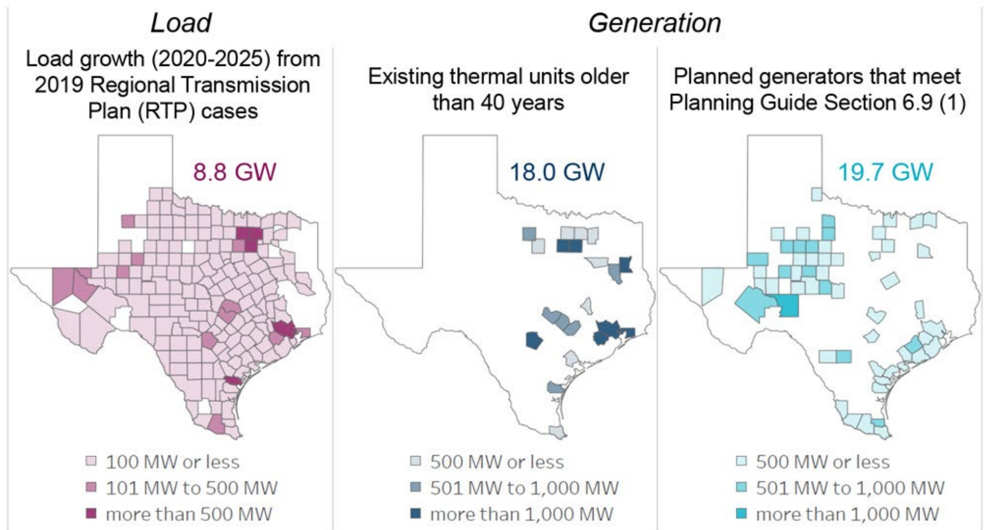
Interconnecting resources are increasingly requesting remedial action schemes (RASes) as a protection scheme. These hardwired relay systems detect predetermined system conditions and automatically take corrective actions, which can include transmission reconfiguration and load sheds or generation trips that allow resources to produce beyond local transmission constraints.

"When [an RAS] sees a condition, it doesn't call the operator. It acts," Rickerson said. "A lot of study goes into them from a reliability standpoint. It's something you really have to pay attention to."

ERCOT has drafted a change to the Nodal Operating Guide (*NOGRR215*) that is currently winding its way through the stakeholder process. The change proposes boundaries for new RASes that limit reliability risks associated with their potential widespread use.

The schemes were a major topic of conversation last week during a *workshop* on transmission issues related to generation constraints. EDF Renewables, SolarPrime and other renewable interests submitted presentations advocating for RASes and the need to meet economic criteria.

The grid operator also relies on generic transmission constraints (GTCs), predefined collections of transmission elements, to maintain grid reliability to subject the aggregate power flow to a defined limit in real time. This is necessary because economic dispatch, reliability unit commitment and other existing market tools are not capable of calculating other operating limits.



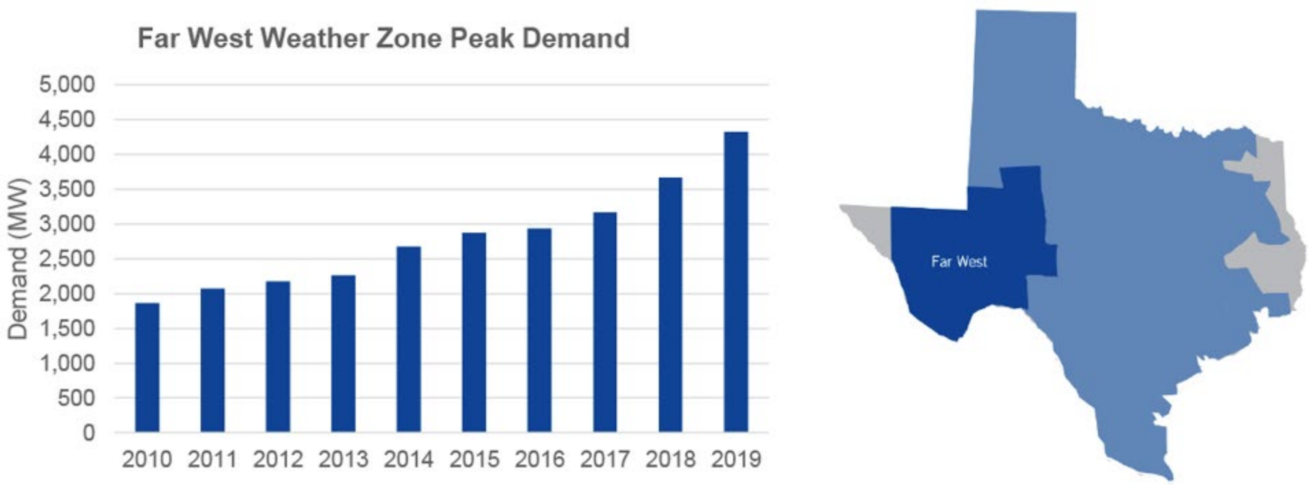
ERCOT's new generation resources are mostly in West Texas, while demand is in the east and south. | *ERCOT*

ERCOT held a GTC-themed workshop in February and has drafted a *GTC white paper* to educate and inform stakeholders.

Five of the grid operator's 12 GTCs can be found in South Texas, which faces both import (reliability) and export (economic) stability constraints. LNG facilities in the Rio Grande Valley could require up to $1.2 billion in transmission improvements and additional generation development in the region could lead to further stability constraints.

ERCOT's other staff-flagged transmission-constrained areas include:

- The Northwest Dallas-Fort Worth Import: One of the highest congested areas in recent planning studies, generation development northwest of the DFW area and load growth within the metroplex is expected to exceed the region's transmission capacity. Rickerson said staff are actively analyzing project options to relieve these constraints.
- Houston-Freeport Import: The *Houston Import* went into service in 2018 and the Freeport Import will be completed in 2021. (See *ERCOT Stakeholders OK $246.7M in Freeport Reliability Projects*.) However, the 2014 Houston Import Project study indicated additional upgrades would be needed by 2027 to continue meeting reliability criteria. Recent planning studies indicate congestion will increase in coming years as power is imported into the Houston and Freeport areas. ■



The Delaware Basin's peak demand has been steadily increasing. | *ERCOT*

ISO-NE News

FERC Rejects Exelon's Mystic Complaints Against ISO-NE

By Tom Kleckner

FERC last week rejected Exelon's complaint against ISO-NE alleging that the RTO's request for proposals for competitive transmission projects addressing reliability needs in the Boston area violated its Tariff (*EL20-52*).

Exelon's Constellation Mystic Power filed the complaint in June on behalf of its *Mystic Generating Station*, an eight-unit, 2-GW fossil-fuel power plant north of Boston. Constellation charged that ISO-NE was putting the region's reliability at risk "by prematurely substituting the uncertain outcome" of its RFP "for the certainty provided by Mystic." (See *Exelon Challenges ISO-NE RFP in Bid to Extend Mystic*.)

The complaint came two days after the grid operator's announcement that it had awarded its first RFP under FERC Order 1000, a $49 million project, to incumbent utilities National Grid and Eversource Energy. (See *ISO-NE Chooses Incumbent as Boston RFP Winner*.)

The RFP was issued to address transmission violations expected with the closing of Mystic Units 8 and 9, whose retirement was extended to May 30, 2024, under a two-year, $400 million cost-of-service contract to preserve the region's reliability. The National Grid-Eversource project has an in-service date of Oct. 1, 2023, eight months before the end of the contract.

Exelon has been trying to extend the plant's cost-of-service contract for an additional year. It said ISO-NE violated its Tariff by short-cutting its transmission security review and prematurely culling bids (36 were submitted) received in response to the solicitation.

FERC on Aug. 17 found that the RFP results provided the grid operator with "sufficient information" to ensure it can address reliability criteria violations without the two retired units. It said ISO-NE conducted the Boston-area needs assessment "to assess transmission security needs resulting" from Mystic 8's and 9's retirements.

"Based on the [assessment's] results … ISO-NE issued the corresponding Boston RFP, which was designed to address the transmission security needs caused by the retirement of Mystic 8 and 9 and involved modeling of whether each proposal addresses the identified reliability needs," the commission wrote. "For those reasons, we find that ISO-NE was not required and, given the information it obtained from the Boston RFP results, had no need to use the network model in order to comply with [the] Tariff."

FERC also disagreed with Constellation's argument that the RTO had violated or circumvented the Tariff by depriving Mystic 8 and 9 of being able to receive compensation from the February 2021 forward capacity auction (FCA) for providing transmission security.

The commission also rejected Constellation's contention that ISO-NE modified its planning procedures to qualify the National Grid-Eversource project in time for Forward Capacity Auction 15 in 2021, which will procure resources for capacity commitment period 2024/25. The New England Power Pool Participants Committee in June approved over Exelon's opposition Planning Procedure 10 (*PP10*), revising the rules for determining whether planned transmission can be included in the network model for the studied capacity commitment period.

Mystic Generation Station | *Anbaric Development Partners*

FERC said the revision is consistent with ISO-NE's existing authority under its Tariff "to consider transmission enhancements that may address its reliability concerns." It noted that the RTO said PP-10 is a business practice manual intended to "detail requirements and procedures … that are conducted pursuant to" the Tariff's provisions.

The commission further noted that ISO-NE's Tariff allows it to consider transmission projects as part of its transmission security review, giving the RTO "broad authority to address reliability concerns arising from the retirement of a resource 'through other reasonable means (including transmission enhancements).'"

Exelon announced the retirement of Mystic 8 and 9 for economic reasons, citing the plant's dependence on more expensive LNG than natural gas from pipelines. ■

ISO-NE News

ISO-NE to Eliminate Performance Payments for EE

By Rich Heidorn Jr.

ISO-NE told stakeholders Friday it will file a rule change with FERC to eliminate capacity performance payments from energy efficiency resources, endorsing a proposal by LS Power.

Henry Yoshimura, the RTO's director of demand resource strategy, told the New England Power Pool's Budget and Finance Subcommittee that the change to Market Rule 1 would improve the design of the Forward Capacity Market.

In a memo to committee members, Yoshimura said the change is a recognition that EE resources "permanently reduce energy consumption [and] create a reduction of demand across all conditions and prices."

Capacity performance payments, which are intended to provide resources with incentives to provide energy or reserves in real time, should be limited "to those resources whose performance could be at risk," Yoshimura said, citing generators, imports, batteries and demand response. In contrast, EE has no real-time performance and thus can't trip offline, Yoshimura said.

The RTO also will change its Financial Assurance Policy (FAP) to eliminate EE's requirement to provide collateral for the FCM delivery financial assurance to cover negative capacity performance changes.

In a presentation to the NEPOOL Markets Committee in June, LS Power's Mark Spencer said EE resources were charged $551,000, its pro rata share of the insurance pool, for a Capacity Scarcity Condition event on Sept. 3, 2018, because the actual event occurred during hours when EE is not measured and scored.

Had the event occurred during DR on-peak hours, at the current Pay-for-Performance (PfP) cap of $5,455/MWh, EE would have received net payments of at least $13.1 million, Spencer told the committee in July.

Spencer said most EE funding comes from surcharges to retail customers and Regional Greenhouse Gas Initiative revenues, with capacity markets providing 7 to 29% of total revenues. He said "long-run expectations" of PfP to total funding are "likely less than 1%."

The proposed change to Market Rule 1 will be presented to the MC in September.

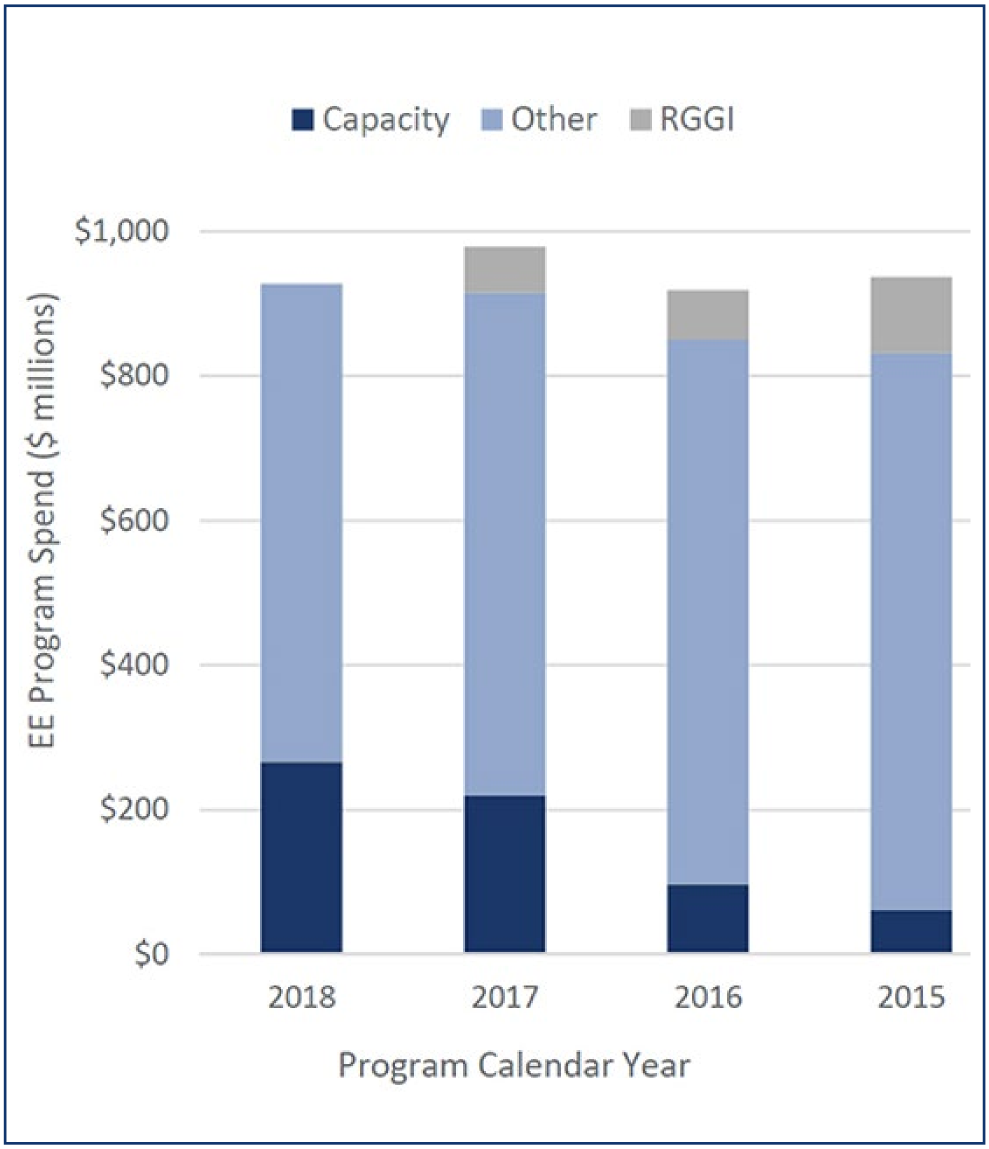
RTO to Close Loophole on Prior Defaults

The RTO also presented a revision to the FAP to bar applicants with prior uncured payment defaults from rejoining the market under a new name. Action on the "Know Your Customer" changes was postponed at the NEPOOL Participants Committee meeting June 23 to evaluate stakeholder concerns.

"The ISO will evaluate relevant factors to determine if an entity seeking to participate in the New England markets under a different name, affiliation or organization, should be treated as the same customer or applicant that experienced the previous payment default," the new language says. "Such factors may include, but are not limited to, the interconnectedness of the business relationships, overlap in relevant personnel, similarity of business activities, overlap of customer base and the business engaged in prior to the attempted re-entry."

Applicants would not be required to cure a payment default that was discharged through bankruptcy.

The RTO will create a "frequently asked questions" document on the proposal and resume discussions at the Budget and Finance Subcommittee's next meeting in October. ■



Most energy efficiency funding comes from surcharges to retail customers (listed as "other") and Regional Greenhouse Gas Initiative revenues, with capacity markets providing 7 to 29% of total revenues. | *LS Power, using data from aceee.org and rggi.org*

ISO-NE News

Coastal States Seek Balance on Offshore Wind

Network Tx Eyed — but not for Initial Projects

By Rich Heidorn Jr.

Speaking at the Business Network for Offshore Wind's virtual International Partnering Forum were, clockwise from top left: Rob Gramlich, Grid Strategies; Ken Seiler, PJM; Joseph Fiordaliso, president of the New Jersey BPU; Stephen Pike, CEO of the Massachusetts Clean Energy Center; and Doreen Harris, acting CEO of NYSERDA. | *Business Network for Offshore Wind*

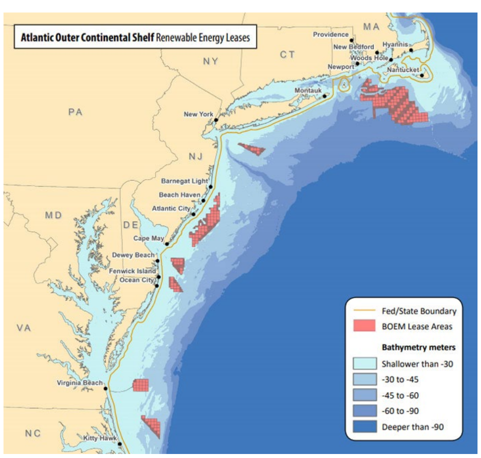
Officials of East Coast states with ambitious offshore wind goals said Thursday they are trying to balance the urgency of getting turbines in the water with potential economies of networked transmission.

"States have initiated what I would say is a process of execution and planning simultaneously," said Doreen Harris, acting CEO of the New York State Energy Research and Development Authority (NYSERDA) during a virtual panel discussion at the Business Network for Offshore Wind's 2020 International Partnering Forum. "None of us are in a position to necessarily wait for the exact planning exercises to be concluded and installed before we move forward with our strong commitments to offshore wind."

"We're anxious to see that first turbine in the water … but you always have to think about the ratepayer," said Joseph Fiordaliso, president of the New Jersey Board of Public Utilities. "Shared transmission can be very helpful and economical in comparison [to transmission for individual developers] for all those states on the coast. We have said to our neighbors more than once we think that there could be a very good collaborative effort as far as transmission is concerned."

New Jersey Goals

New Jersey, which has a goal of 7,500 MW of OSW by 2035, has awarded an 1,100-MW solicitation and will award up to 2,400 MW more early next year.



PJM has five coastal states that could develop offshore wind: New Jersey, Delaware, Maryland, Virginia and North Carolina. | *BOEM*

"Everyone who comes into [my] office has a different idea about transmission: Should the developer do it along with setting up the wind turbines? Should you have … independent transmission?" Fiordaliso said.

The BPU *hired* consultant Levitan & Associates to help it evaluate its alternatives, he said. The board's studies indicate that "anything beyond 3,500 MW may … need a shared network of transmission. … Solicitations 1 and 2 can successfully be handled with bundled generation and transmission. Once we get to procurements 3 to 6, we are pursuing really a shared-network approach."

Although the current solicitation calls for bundled generation and transmission, it also required applicants to include plans for using a shared network and to allowing others to use the applicants' facilities, he said.

New England Looks for 'Break Point'

The New England States Committee on Electricity (NESCOE) asked ISO-NE to identify the "break point" between existing or near-term transmission opportunities and long-term needs, said Stephen Pike, CEO of the *Massachusetts Clean Energy Center*. "They found there is roughly 8 GW of interconnection capacity in Southern New England that can be used before you need significant onshore upgrades; it was broken out to roughly 6 GW on AC and then 2-plus GW on HVDC technology."

Those thresholds are coming fast, Pike said. "You could see that capacity essentially accounted for in the relatively near term, and … should we want to go to some sort of independent/shared transmission system, we need to start planning now for that. I don't think we have a whole heck of a lot of time to waste. … I do think that we need to start that process in earnest in the very near term in order to be prepared for some of these … market triggers. I see 8 GW or even 6 GW being a really critical trigger."

New York Seeks to 'Accelerate'

NYSERDA issued a *solicitation* in July for up to 2,500 MW of OSW to meet New York Gov. Andrew Cuomo's goal of 9 GW by 2035. (See *NY Announces 4 GW in Clean Energy RFPs*.)

Harris said the state is planning for the future grid and executing its radial transmission procurements simultaneously "to maintain New York's market momentum and to utilize the existing federal lease areas that are available."

"Acceleration … is our mantra," she said, citing the state's streamlined siting process for transmission and generation. "We are looking to install transmission much more quickly than had been the case historically." (See *Cuomo Proposes Streamlining NY's Renewable Siting*.)

ISO-NE News

New York currently has three 345-kV transmission projects in the siting process that are intended to eliminate choke points preventing upstate renewables from serving downstate loads. The Long Island Power Authority is looking to increase the island's export capability to deliver OSW to the rest of the state by expanding its 138-kV backbone, Harris said. (See *NY PSC Gets Update on Tx Planning, Investment Efforts*.)

The strategy for offshore transmission "is very contingent on the availability and conversion of additional wind energy areas for offshore wind development, which really needs to be resolved in advance for us to conclude our grid study on the wet side of the equation [offshore transmission] to get on with detailed planning and execution," she said.

A *study* released in August by Wood Mackenzie for the American Wind Energy Association and the New York Offshore Wind Alliance said more leases in the *New York Bight* would create 30,000 construction jobs and deliver as much as $800 million in lease revenue for the federal government.

"For us, it's a no-brainer from an economic development perspective," she said.

She talked of the need to "balance" the economics, "which is to say that the most optimized wet offshore grid … may not ultimately result in the most optimized, cost-effective onshore grid. So, the balance of issues, particularly in spatially congested areas like New York, [is] critically important."

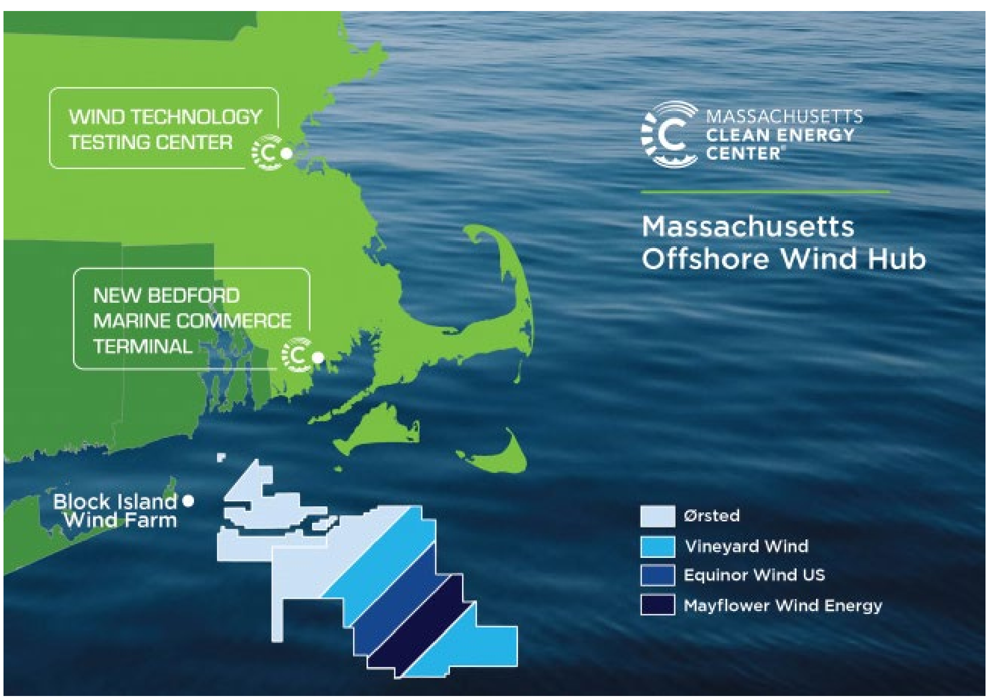
Similarly, while running fewer cables would appear to be the most efficient and environmentally friendly approach, that would not be the case if those routes "run afoul of key maritime corridors or commercial fishing grounds or environmentally sensitive areas," she said. "So, the question of financial efficiency needs to be balanced with the broad impacts as a whole."

"We do sit in the middle. Although a single-state ISO, we are proximal to New England and PJM in a way that inevitably will bring these issues to bear. I would say it's not the focus of our current power grid study, which is focused on the integration within New York. But these interties and cost allocation issues that President Fiordaliso mentioned are certainly paramount when we start to broaden our scope."

Why not More Proactive?

Moderator Rob Gramlich of Grid Strategies asked why PJM had not taken a proactive view on planning, citing transmission built to serve wind generators in California's Tehachapi Pass, Texas' Competitive Renewable Energy Zones and MISO's Multi-Value Projects. PJM has five coastal states that could develop OSW: New Jersey, Delaware, Maryland, Virginia and North Carolina. (See related story, *Md. PSC Approves Larger OSW Turbines*.)

"We don't count on those megawatts being there until we have public policy," responded Ken Seiler, PJM's vice president of planning.



Massachusetts' offshore wind "hub" | *Massachusetts Clean Energy Center*

He added, "If all the … five coastal states execute on some of the renewable portfolio standards they have in place right now, there will be [transmission] upgrades in other states that are not coastal."

Seiler said OSW is just the latest development in PJM's transformation. The RTO, which has interconnected 10 GW of wind so far, currently has 120 GW of proposed generation and storage in its interconnection queue, including more than 56 GW of solar, 13 GW of solar with storage, almost 13 GW of onshore wind and another 13.5 GW of OSW.

"We have traditionally [had] a West-East flow, with [coal] mine mouth units in the West feeding large load centers in the East," and generation dominated by coal and nuclear, Seiler said. "Then we moved into the gas era with the Marcellus and Utica shale … which [resulted in the growth of gas-fired generators built] closer to the load centers. And now we're talking about solar and offshore wind."

Seiler said PJM planners are having ongoing discussions with their counterparts in Germany to learn about what Europe has done to accommodate its OSW.

One challenge will be determining who pays for the additional transmission, he said. "Cost allocation, obviously, is in the eye of the beholder. What may be fair to you may not be fair to me. … Either the cost causer pays, or the beneficiary pays. There's two ways to do it, and there's other ways [we could] come up with.

"We ideally would like to see federal policy around some of this that would help enable states and us to accomplish these goals. That doesn't seem to be in the cards, at least in the near term. We're going to have to collaborate, coordinate [and] communicate. This is all new to many of us. But it's an exciting time, and I think we have the right people at the table to figure this all out." (FERC has scheduled a *technical conference* for Oct. 27 on integrating OSW in RTOs and ISOs.)

Pike said meeting the states' goals will require "multilevel coordination," beginning with "engagement at the local level," where the offshore transmission meets the land-based grid.

"You're going to need that local layer; you're going to need the state level, as well as states talking across regions; and you're going to need it at the ISO level, working across ISOs," he said. "I won't try to convince folks that I know exactly what the process is moving forward, but I do feel as though we've taken a couple of good first steps." ■

MISO News

MISO Board Primed for 1st Major Interregional Project

By Amanda Durish Cook

| PJM

MISO's Board of Directors is expected next month to approve MISO and PJM's first major interregional transmission project, about a year after the RTOs first recommended it.

The nearly $25 million *reconstruction* of the 138-kV Michigan City-Trail Creek-Bosserman line in Indiana's northwestern corner was identified last fall in the 2018/2019 MISO-PJM coordinated system plan. (See *MISO, PJM Poised for 1st Major Interregional Project*.)

Project costs will be split on a 90-10 basis, with PJM covering the larger share. The 11-mile rebuild is located in MISO's Northern Indiana Public Service Co.'s (NIPSCO) transmission zone and is expected to be in service by January 2023.

PJM's Board of Managers approved the project at its December 2019 meeting. MISO's board has yet to meet for a vote.

MISO's nine-month approval lag comes because it did not have a cost-sharing plan in place for its interregional market efficiency projects (MEPs). After twice rejecting the RTO's cost-allocation plans, FERC in April prescribed MISO use a design based on adjusted production costs savings for economic interregional projects 100 kV and above with PJM. (See *Another Rejection for MISO Cost Allocation Plan*.)

"Now that we have cost allocation in place, MISO is going to present this project to our Board of Directors meeting in September to put the final touches on that project approval," MISO Economic and Policy Planning Adviser Ben Stearney told stakeholders during a virtual MISO-PJM Joint and Common Markets meeting Aug. 18.

MISO staff had proposed the project not be regionally allocated in the RTO, reasoning that its 138-kV rating disqualified it from allocation beyond the transmission pricing zone where MISO's project share is located. The RTO's two rejected cost-allocation filings reserved regional allocation for interregional MEPs 230 kV and above.

FERC in 2016 lowered MISO's interregional economic project voltage threshold from 345 kV to 100 kV after a 2013 NIPSCO complaint over the MISO-PJM interregional planning process.

No 2020 Coordinated Plan

There are currently no additional interregional projects on the horizon for the RTOs, which have agreed not to start a two-year coordinated system plan study in 2020.

"We didn't find any strong issues to support a study," Stearney said, adding that the RTOs will continue to gather and analyze historical congestion data. He said they will meet in the fourth quarter to discuss potential economic needs and the possibility of a CSP that would begin next year. ■

MISO News

MISO AC Works on Sector Rules as FERC Timeline Ticks

By Amanda Durish Cook

MISO's Advisory Committee is on a tight schedule to redesign the RTO's sector setup.

The committee met virtually Wednesday to discuss possible design elements, a month after FERC said MISO's creation of the Affiliate sector as a repository for new difficult-to-define members was fair only on a temporary basis.

FERC approved the sector late last month but gave MISO until March 2021 to work out a more permanent member-sorting process and representation model that affords full participation to all members. The commission said the RTO should be swift in forming a long-term equitable solution and said it would investigate the arrangement if left unrevised, a warning that had Commissioner Richard Glick crying foul. (See *New MISO Sector Gets FERC OK — with a Catch*.)

The Affiliate sector currently *contains* North Dakota coal-lobbying group Lignite Energy Council, coal trade organization America's Power, and several chambers of commerce and mining organizations. It also contains conservative lobbying group Center of the American Experiment and sustainability and conservation trade association Minnesota Forest Industries.

The AC is now asking whether the new sector should be allowed to vote on recommendations to the MISO Board of Directors. The sector cannot vote for the time being, but it can offer opinions during discussions with the board during the committee's quarterly meetings.

The Union of Concerned Scientists' Sam Gomberg said he would be concerned if MISO discussions took a more political turn. He said the RTO has historically been very good about minimizing politics in its guided policy conversations.

Some AC members argued that the Affiliate sector's miscellaneous status means that members would not reach enough of a consensus to cast votes. Others said all MISO sectors should have a vote.

"Voting is more *de minimis* and often a rarity. We do a lot of things by consent," AC Chair Audrey Penner said. "When we do vote, we're voting on pretty important issues."

AC votes are nonbinding and advisory in nature to the board and MISO staff.

The committee has already decided the board will have the final say in creating new sectors and MISO will be the final arbiter when a disagreement occurs over whether an organization is a good fit for a certain sector. Sectors must also establish their membership criteria and post them on the public MISO website. (See *MISO Members Make 1st Rules on Sectors*.)

The AC is now asking if it should consolidate some of its 10 other existing sectors. With 11 sectors, MISO has more than any other RTO or ISO. The committee is asking how many is too many.

Independent Power Producers and Exempt Wholesale Generators sector representative Travis Stewart said the sheer number of people participating can make the AC's quarterly "hot topic" discussions before the board chaotic. He said a more structured discussion with fewer representatives per sector could yield more streamlined discussions.

Some members said sectors don't need to be thinned or merged; instead, they need more face time with the board. A few proposed that sector representatives form a liaison committee to the board in order to get more access to and interaction with it.

"MISO does have a very different access to the Board of Directors. And this is my personal view: It's much more controlled," said Beth Soholt, representative of the Environmental and Other Stakeholder Groups sector. "Other RTOs have unfettered access to their boards." ■

Lignite Energy Council headquarters in Bismarck, N.D. | *LEC*

MISO News

La. PSC Strikes out Again in Entergy Bandwidth Case

By Amanda Durish Cook

FERC last week rejected a new argument by the Louisiana Public Service Commission in a 17-year-old case tied to a now terminated agreement among Entergy's operating companies (*EL01-88-023*).

Having previously faced rejection from FERC, the PSC framed its argument for refunds to Entergy Louisiana customers in a new light, this time claiming that Entergy's System Agreement itself — not the Federal Power Act, as the PSC originally thought — was the basis for the "rough equalization" of costs requirement.

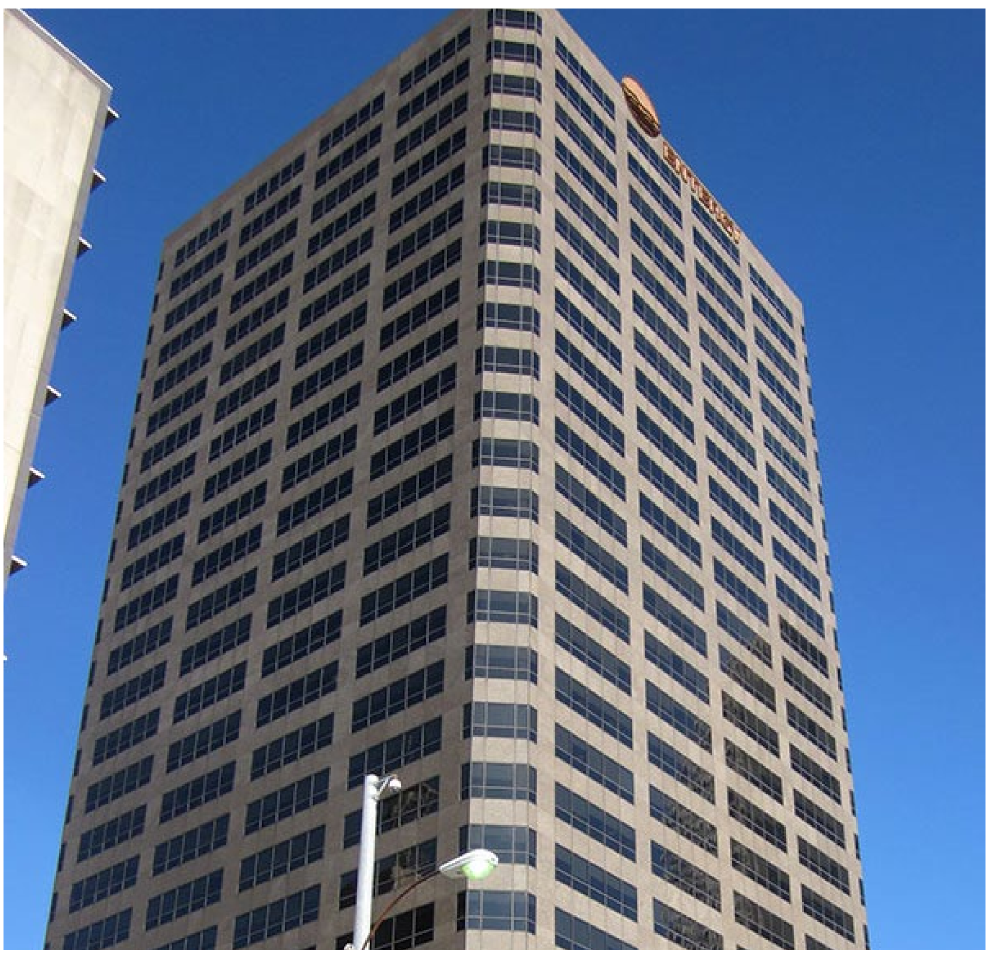
Prior to 2015, the Entergy operating companies functioned as one system across four states, although each had different operating costs. FERC in 2005 determined that production costs across the multistate Entergy system were not as equal as Entergy promised and imposed a bandwidth payment remedy among the companies, spurring litigation that's lasted several years. (See *FERC Affirms Ruling Favoring Entergy Bandwidth Calculation*.)

The Louisiana PSC has mounted multiple attempts to compel refunds for the period before the 2005 solution, arguing that "large disparities in production costs" began showing up in 2000 without Entergy attempting to distribute production costs more evenly in accordance with its 1982 System Agreement.

This time, the PSC requested rehearing of FERC's decision not to order refunds for 2001-2003 and asked it to consider a new refund period from 2003 through mid-2005 on the basis that Entergy violated its own tariff, not the FPA. (See *La. PSC Complaints Denied in Entergy System Disputes*.)

FERC refused both requests on Aug. 18.

"We are not persuaded by the Louisiana commission's arguments on rehearing concerning its new refund claim, and we continue to find that it was too late in this 17-year-old proceeding for the Louisiana commission to change its theory of the case and raise a new claim," FERC said.


Entergy Tower in New Orleans

Beyond that, the commission said the now defunct System Agreement and the FPA are not the same.

"The System Agreement and the FPA therefore do not constitute potential alternative bases for the rough equalization requirement. Rather, the System Agreement has been structured in a way that was intended to achieve rough equalization and thereby satisfy FPA standards," FERC said.

It also said the PSC failed to point out a provision of the System Agreement that Entergy violated.

"Instead, it treats rough equalization as a general, albeit unarticulated, duty applicable to the parties, rather than as a result that the specific duties set forth in the System Agreement are expected to achieve," FERC said.

The PSC has long argued that Entergy Arkansas "reaped" over-collections of system payments. In its order, FERC again reminded the PSC that Entergy as a whole didn't over-collect on rates.

"The Entergy Operating Companies operate[d] on a single-system basis, and this case involves a zero-sum allocation of costs among the operating companies under the System Agreement," FERC said.

Entergy Arkansas gave notice in 2005 to leave the System Agreement in 2013, asserting it was effectively subsidizing the other Entergy companies. Entergy Mississippi followed in 2007, seeking a 2015 exit. FERC approved the departures in 2009 and ruled that neither utility was bound to compensate the remaining unified Entergy companies upon their departures.

The PSC also argued that the presiding judge over the bandwidth remedy issue in 2005 implied that refunds were appropriate for the 2003-2005 period and that FERC could use its discretion bestowed under Section 309 of the FPA to go beyond the law itself and order refunds beyond a 15-month span.

FERC said the reference to Section 309 was an invention of the PSC and that it couldn't "identify any pleading or order in the long history of this proceeding that invokes, or even mentions, FPA Section 309." ■

MISO News

Memphis Moves Closer to Breaking from TVA

By Amanda Durish Cook

Memphis Light, Gas and Water took another step away from the Tennessee Valley Authority last week as staff recommended the utility issue its first ever request for proposals for new energy sources.

MLGW staff made the recommendation to its Board of Commissioners at a Wednesday *meeting* after conducting a yearlong review of resource alternatives to TVA.

The utility could begin the RFP process in October, with approval from its board and the Memphis City Council. The MLGW board and the city council meet every two weeks. Neither entity has announced an intention to hold a vote on the matter.

MLGW President J.T. Young announced that the utility will hire a consultant to help manage the bidding process. Young was also clear during the meeting that MLGW had not yet decided whether it would depart TVA.

Earlier this year, the city-owned utility said it was eyeing MISO membership or joining another wholesale supplier as a more economic alternative to TVA, its electricity provider for 81 years. (See *Memphis Muni Mulls Move to MISO*.)

MLGW currently accounts for about 10% of TVA load and pays about $1 billion a year for power. To split with the federally owned corporation, Memphis would likely procure some of its own resources and look to a new wholesaler for the rest. MLGW doesn't currently generate any of its own electricity.

"This historic decision sets up MLGW to provide more value to customers in Memphis and be a national leader on clean energy," Southern Alliance for Clean Energy (SACE) Executive Director and MLGW adviser Stephen Smith said in an emailed statement. "By seeking bids on alternative power supplies, the people of Memphis ... will lock in lower-cost and cleaner, more efficient energy, giving Memphis more control of its own future. This also serves as a significant 'shot across the bow' to TVA that MLGW is setting the stage to break loose from TVA's dictatorial long-term contract arrangements."

An MLGW-commissioned Siemens *study* found that certain combinations of self-supply and MISO wholesale market offerings could save Memphis about $150 million per year from 2025 to 2039, while cutting carbon emissions by as much as 50% by 2030.

TVA said it "respects and supports" the utility's decision to explore an RFP from alternative suppliers, though it touted itself as the better option over self-supply and the markets across the Mississippi River.

"We are excited about the opportunity to engage in the RFP process — to put the facts on the table — and prove that TVA in partnership with MLGW is the best option for the people of Memphis and Shelby County," TVA said in a *statement*. "When it comes to energy costs, Memphis starts from a position of strength. In partnership with TVA, MLGW today provides the third-lowest energy costs in the nation among its peers. TVA's commitment is to keep energy costs stable over the next decade."

MLGW said its electricity rates are competitive when *compared* to other major U.S. cities.

Citizens have said a parting with TVA would bring desperately needed affordable energy to Memphis, where about a third of its residents live at or below the poverty line.

"In the past, and especially now during the COVID-19 pandemic, I see parents being forced to decide between paying to keep the lights on or buying medicine or shoes for their kids. That's not how it should be in the future, when Memphis buys or produces its own power and takes control of its own power supply," Pearl Eva Walker, an organizer with grassroots social justice group *Memphis has the Power*, said in a press release.

SACE has recommended that MLGW issue two RFPs: one for a large-scale energy-efficiency program on a five-year horizon, creating savings as the municipality navigates leaving TVA, and another for clean resources and supporting infrastructure beyond a five-year horizon. ■

Memphis riverfront | *TVA*

NYISO News

NYISO Nearing Vote on Hybrid Rules

By Rich Heidorn Jr.

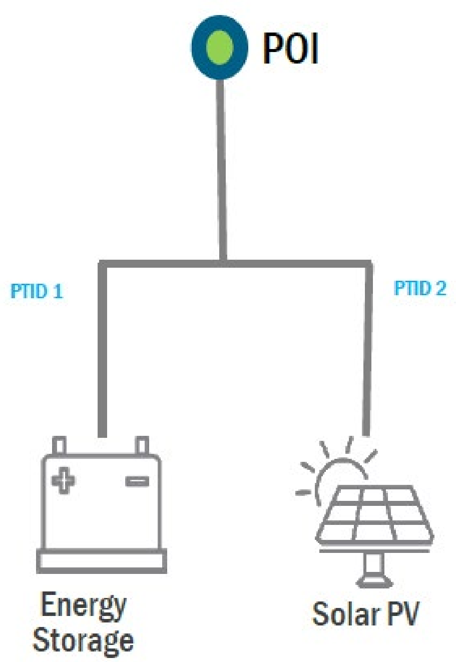
NYISO is nearing a vote on market participation rules for hybrid storage and generation resources, with plans to submit the proposal to FERC in 2021.

Stakeholders on Wednesday spent more than three hours discussing proposed Tariff language on co-located, front-of-the-meter energy storage and wind or solar generation.

The ISO's proposal would allow each unit in a co-located storage resource (CSR) to have its own single point identifier — one for the energy storage resource (ESR), and one for the wind or solar generator, referred to as an intermittent power resource. Each unit also would have separate energy resource interconnection service (ERIS) and capacity resource interconnection service (CRIS) values.

The CSR units would be settled at the locational-based marginal price at the point of interconnection. Only the ESR unit would be eligible to provide reserves or regulation.

| 8minute Solar Energy



NYISO's proposal would allow each unit in a co-located storage resource (CSR) to have its own single point identifier (PTID) — one for the energy storage resource (ESR), and one for the wind or solar generator, referred to as an intermittent power resource (IPR). Each unit also would have separate energy resource interconnection service (ERIS) and capacity resource interconnection service (CRIS) values. | *NYISO*

The ISO, which has held seven prior meetings since beginning the hybrid storage project in January, had considered two other participation options in May but decided not to propose them. (See *NYISO Explores Hybrid Interconnection Processes*.)

NYISO will use a scheduling constraint to determine feasible energy and reserve schedules for units within the CSR, the ISO's Kanchan Upadhyay *told* stakeholders during a joint meeting of the Market Issues, Installed Capacity and Price Responsive Load working groups.

Resources serving a host load would not be permitted to participate in ISO markets as a CSR. The ISO initially proposed requiring them to participate as a behind-the-meter net generation resource or a distributed energy resource, but officials are reconsidering that based on stakeholder feedback at Wednesday's meeting.

The ISO's Amanda Myott *led* a discussion on proposed Tariff revisions governing CRIS for hybrid generation and storage.

The ERIS for the intermittent generator would be limited to the CSR injection capability plus the full withdrawal capability of the storage resource.

Under proposed transition rules, projects with separate positions in the interconnection queue as of the effective date of the Tariff changes could combine and proceed under a single interconnection request as a CSR as long as both projects are behind the same point of injection.

Sarah Carkner gave a *presentation* on proposed ESR bidding rules for installed capacity (ICAP) suppliers with an energy-duration limitation.

The ISO originally proposed requiring that ESR ICAP suppliers use the ISO-managed energy level bidding parameter for their day-ahead bids.

FERC, however, said the proposal did not comply with Order 841's requirement "to allow resources using the participation model for electric storage resources to self-manage their state of charge." It ordered NYISO to allow ESRs that supply capacity to bid either ISO-managed or self-managed.

Earlier this year, FERC approved NYISO's proposal to require the ESR ICAP supplier to bid, schedule and notify the ISO of its full range, from withdrawal to injection. (See *NYISO's 2nd Storage Compliance Almost Hits Mark*.)

NYISO proposes requiring ESR ICAP suppliers with an energy-duration limitation to either bid or schedule a bilateral transaction for their full injection range for all hours during the "peak load window," or notify the ISO of a derate. For hours outside of the peak load window, they would be required to bid their full withdrawal range or notify the ISO of a derate. (The peak load window is between the hours beginning 13-18 in summer and 16-21 in winter. When the system reaches 1,000 MW of duration-limited resources, the window will increase from six to eight hours.)

The ISO plans to bring the new bidding rules for ESR ICAP suppliers with an energy-duration limitation to upcoming meetings of the Business Issues and Management committees and have them effective for the day-ahead market run for May 1, 2021. ■

PJM News

NJ Senate Exploring Exit from PJM

Continued from page 1

Lawmakers cited FERC's Dec. 19 order expanding the PJM minimum offer price rule (MOPR) to all new state-subsidized resources as an impetus behind the bill. New Jersey was among several states to ask FERC in January to rehear the order. (See *PJM MOPR Rehearing Requests Pour into FERC*.)

Smith emphasized that his bill was not aimed at making any definitive answer as to leaving PJM but was created as a way for the BPU to analyze different options for the state's electric grid and the potential impacts on ratepayers, utilities and energy generators.

"I actually had a whole bunch of calls about this bill saying, 'What's the real agenda?' The real agenda is to get information," Smith said during the hearing. "Nobody's made a decision we want to leave PJM. Nobody's made a decision we want to stay in PJM."

Bill Language

The bill would require the BPU to conduct a study analyzing and comparing the potential costs and benefit impacts of five different scenarios, including:

- withdrawing from PJM and "establishing an electric transmission grid operating independently within New Jersey";
- withdrawing from PJM and joining NYISO;
- remaining with PJM;
- any other electric transmission grid option that the BPU may consider to be "in the best interest of ratepayers of the state";
- using the fixed resource requirement (FRR) alternative to satisfy the state's resource adequacy needs and accelerate achievement of the state's clean energy goals.

The BPU would be required to submit a written report to Gov. Phil Murphy and the legislature concerning the study results within a year of the bill's passage, including the costs and impacts on renewable energy production, energy storage and distributed electric generation in the state. It also requires the study of any costs, physical or structural changes or regulatory approvals needed if there is a withdrawal from PJM.

The bill requires consultation with stakeholders, including power suppliers and public utilities, FERC, NERC and public and private entities that have conducted studies on transmission grids.

Smith said the BPU has already started public discussions mulling the implications of leaving the PJM capacity market in favor of the FRR option. (See *N.J. Investigating Alternatives to PJM Capacity Market*.) He said he doesn't want the legislature to be "the dumbest group in the room" and not have enough information to make an educated decision.

"For anyone out there in the energy world, we're not sending you a signal that we're leaving PJM," Smith said. "We're sending you a signal that we want to be more informed rather than less informed."

Current BPU Actions

New Jersey regulators have already taken the first steps in determining whether the state should remain in PJM's capacity market or to go in a different direction to meet the state's electricity needs.

The BPU voted March 27 to investigate if staying in the capacity market will impede Murphy's goals of 100% clean energy sources in the state by 2050 or increase consumer costs (Docket No. *EO20030203*). (See *NJ Unveils Plan for 100% Clean Energy by 2050*.) The BPU received 40 *filings* of comments in response. (See *NJ Regulators Weighing Input on Capacity Market Exit*.)

Some stakeholders said the state should adopt the FRR because the expanded MOPR would hamstring its support for emission-free generation. Opponents said leaving the capacity market could end up costing state ratepayers millions, leaving them at the mercy of monopolistic generators.

Hope Creek Nuclear Generating Station in New Jersey | *NRC*

PJM Perspective

Asim Haque, PJM | *PUCO*

Asim Haque, PJM vice president of state and member services, gave *prepared testimony* at last week's hearing, saying the RTO estimates that its regional operations, transmission planning and operation of wholesale markets saves between $3.2 billion and $4 billion a year, including $360 million to $460 million a year in New Jersey.

Haque's testimony focused on PJM's regional planning role and how New Jersey residents have benefited for more than 90 years being an integral part of the RTO. He said if the state chooses to "go it alone," serious challenges would be presented because of the interstate nature of the transmission grid.

"PJM feels confident that New Jersey would continue to find the greatest value for its consumers in being part of PJM," Haque said. "We believe that the study would show that PJM is the best option for New Jersey and all states in our footprint. Reliability. Affordability. All while trying to assist states in advancing their policy objectives."

He said he is confident that any study conducted by the BPU would result in the state staying with PJM because leaving has "potentially some deleterious impacts to families and businesses in the state of New Jersey."

"I understand that in these challenging times, folks are struggling, and this is an extremely complicated endeavor that could prove to be very costly during times of financial recovery," Haque said. "We do feel confident that New Jersey will continue to find the greatest value for its consumers by being a part of PJM." ■

PJM News

Dominion Energy Buys Rights to Va. Solar Farm

By Michael Yoder

Dominion Energy solar farm in Virginia | *Dominion Energy*

Dominion Energy is adding to its growing solar portfolio with the acquisition of a generating facility scheduled to be built in Central Virginia.

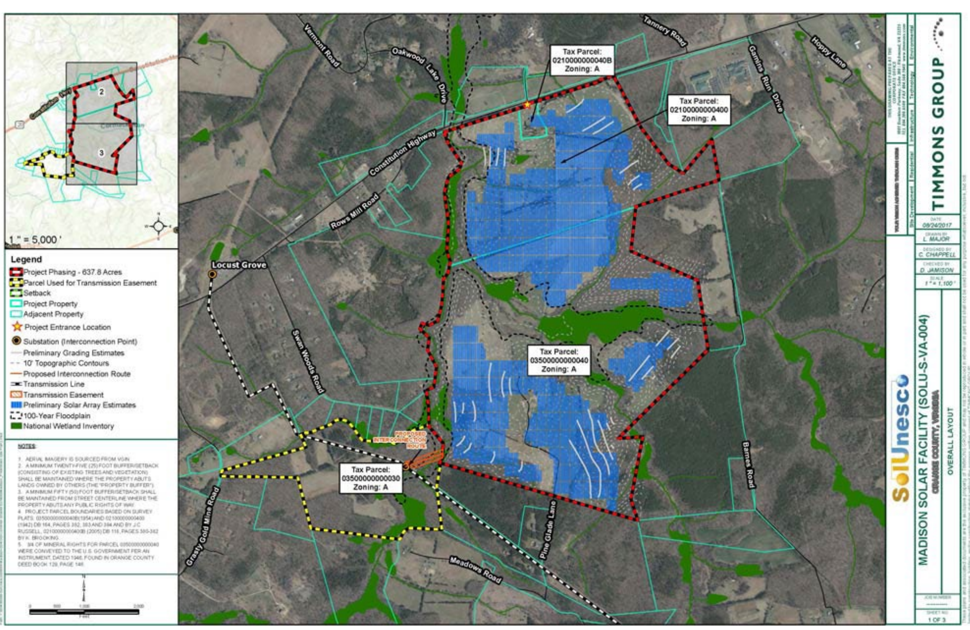
The Richmond-based company last week announced it obtained the rights to the 62.5-MW Madison Solar generating facility in Orange County, Va. The facility, owned by California-based Cypress Creek Renewables, will be transferred to Dominion's contracted assets arm.

Terms of the deal were not disclosed.

Madison Solar has received all state and local permits and is expected to come online by the second quarter of 2022. About 660 acres of land along State Route 20 in Locust Grove are being purchased to house the solar project.

Northrop Grumman will purchase the project's electricity as well as its renewable energy credits under long-term agreements, according to Dominion. Northrop officials said they anticipate the facility will provide enough renewable power to the grid to match 100% of the electricity used for its Virginia manufacturing and office operations.

Dominion is continuing its plans to add about 16 GW of solar generating capacity through company-owned projects and power purchase agreements it is signing with third-party developers in Virginia. Its proposed *long-term integrated resource plan* for 2021-2045 would quadruple the amount of solar and wind generation in its previous 15-year plan a response to the Virginia Clean Economy Act (*House Bill 1526* and *Senate Bill 851*). Signed by Gov. Ralph Northam in April, the law established that 16,100 MW of solar and onshore wind is "in the public interest." (See *Va. 1st Southern State with 100% Clean Energy Target*.)



The original site plan for the proposed Madison Solar generating facility scheduled to be built in Orange County, Va. | *Dominion Energy*

Virginia-based SolUnesco began securing the Madison Solar site in July 2016 before selling it to Sol Systems, a solar developer, and then transferring it to Cypress Creek Renewables in early 2019. The project will interconnect to a 115-kV line utilizing an easement for 0.1 miles from the parcel through an application filed with PJM in November 2017 (*AC1-076*).

"Our mission of powering a sustainable future one project at a time drives us to create valuable partnerships and projects," said Cassidy DeLine, vice president of project finance for Cypress Creek Renewables. "Our collaboration with Dominion and Northrop Grumman on the Madison project reinforces our commitment to developing solar in the nation's largest wholesale electricity market, PJM, and delivering long-term benefits for Orange County, Va." ■

PJM News

Md. PSC Approves Larger OSW Turbines

By Rich Heidorn Jr.

The Maryland Public Service Commission on Thursday approved Skipjack Offshore Energy's decision to use fewer, larger turbines in its offshore wind project, rejecting objections by Ocean City officials.

The PSC awarded offshore wind renewable energy credits (ORECs) for the 120-MW Skipjack project and the 248-MW US Wind project in May 2017.

Skipjack had initially proposed using Siemens' 8-MW turbine but said the selection was subject to change because of continuing improvements in turbine design. In June 2019, Skipjack notified the PSC that it would switch to General Electric's new 12-MW Haliade-X turbine, prompting the commission to solicit comments and hold a public hearing on the change. Skipjack said the Haliade-X would produce more power in medium-wind speeds and increase the project's capacity factor.

The Maryland Energy Administration, the Office of People's Counsel and the commission's technical staff all supported the switch to the larger turbine, saying it is more efficient and could reduce costs for ratepayers.

In its *order* Thursday, the commission concluded that the change is consistent with the Maryland Offshore Wind Energy Act and the public interest because it will allow Skipjack to use only 10 or 12 turbines instead of 15.

The order selecting Skipjack "includes dozens of conditions whose purpose was to mitigate risk to ratepayers and maximize value to the state of Maryland. Included therein is the requirement that Skipjack utilize 'best commercially reasonable efforts to minimize the daytime and nighttime viewshed impacts' of its project, 'including through reliance on best commercially available technology at the time of deployment,'" the commission wrote.

It also said the Haliade-X is "well-suited to the wind conditions in the Mid-Atlantic where low- to medium-wind speeds predominate."

Ocean City contended the larger turbines would have a negative visual impact because they are three times taller than the highest building in the city.

With the new design, the diameter of the turbines' rotors will increase from 590 feet to 721 feet, and the tip height will increase from 641 feet to 853 feet. But the commission noted the 12-MW turbine layout will take up just 7% of the visible horizon from Ocean City versus 18% in the 8-MW configuration. In addition, the nearest turbine will be 21.5 or 22.7 miles from shore versus 19.5 miles as originally planned.

The commission rejected Ocean City's request to order Skipjack to move the wind farm to 33 miles offshore.

"First, the Maryland Offshore Wind Energy Act of 2013 requires that offshore wind turbines be placed between 10 and 30 miles off the coast of the state. If the project is located beyond those geographical constraints, it is not eligible for ORECs approved by the commission," the PSC said. "Second, the Skipjack project must also be located within the specific area of federal waters leased to Skipjack by [the U.S. Bureau of Ocean Energy Management]. BOEM determined the location of the Delaware Wind Energy Area through a multiyear research and review process, which included intergovernmental stakeholder input, including state and local governments along the Delmarva coast. BOEM also considered the location of shipping lanes and other existing uses of the federally regulated outer continental shelf. That multiyear endeavor should not be easily disregarded by the commission."

The PSC, however, scolded Skipjack for what it said were "deficient" outreach efforts to stakeholders. "Skipjack's engagement with Ocean City appears meager. For example, Mayor [Richard W.] Meehan testified that Skipjack has not provided routine outreach to Ocean City representatives or stakeholders for the past several years."

It ordered the developers to "re-engage" with stakeholders and provide the commission reports on its efforts every six months. ■

GE's 12-MW Haliade-X offshore wind turbine prototype | *GE*

PJM MRC Briefs

Market Efficiency Proposals

PJM members last week approved two changes to the RTO's market efficiency project planning process while rejecting a third to create a new regional targeted market efficiency project (RTMEP) process that had been challenged by stakeholders.

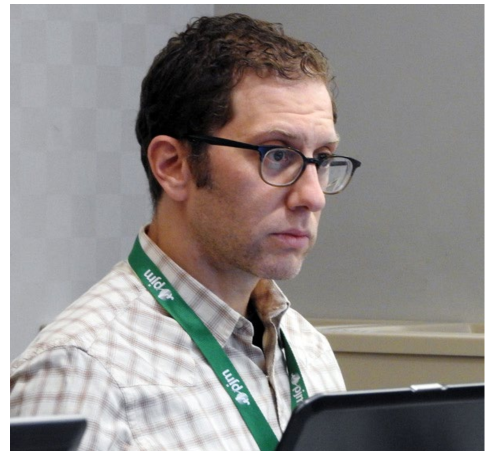
The RTMEP *package* proposed by American Electric Power and FirstEnergy received a sector-weighted vote of 1.56 (31%), failing to meet the 3.33 (66.7%) threshold for passage at Thursday's Market and Reliability Committee meeting. The package, which transmission owners said would target small projects addressing persistent congestion not identified in the forward-looking planning model and would have awarded RTMEPs to the incumbent TO, was opposed by other stakeholders who had criticized it for excluding competition. (See *PJM Stakeholders Debate Market Efficiency Proposals*.)

PJM's *proposal*, which called for 30-day competitive windows to select the developer in the RTMEP process, also failed to garner support, receiving a sector-weighted vote of 2.63 (53%). The AEP-FE proposal originally won 56% support in Planning Committee vote in May, edging out the PJM proposal, which received 55% support.

Brian Chmielewski of PJM said the RTMEP issues have been worked on by stakeholders for more than two years, and the packages were the product of extensive member input. Chmielewski said the idea to examine the RTMEP process originated from the interregional PJM-MISO TMEP planning process that had successfully produced a half-dozen projects.

Steve Lieberman, director of regulatory affairs for American Municipal Power (AMP), said he appreciated the effort that went into the packages, but he said AMP didn't feel like the solutions in the packages were supportable.

"That's not an indication for the need for more discussion," Lieberman said. "We just don't think there's a problem here to be solved."



Steve Lieberman, AMP | © *RTO Insider*

Stakeholders did approve two changes regarding the RTO's existing market efficiency, or "economic," projects.

In a vote on the *benefit calculation metric* MEPs, stakeholders rejected a FirstEnergy solution *package*, which would have averaged multiple Monte Carlo results and run them on Regional Transmission Expansion Plan (RTEP), RTEP+3 and RTEP+6 years. That package failed with a sector-weighted vote of 2.02 (40%).

But PJM's *proposal* and Operating Agreement *revisions*, which would use a single-draw Monte Carlo simulation, with simulations for both Reliability Pricing Model and RTEP years, won support from stakeholders, coming away with a sector-weighted vote of 3.75 (75%).

Stakeholders also approved PJM's *package* to clarify when capacity benefits of MEPs are calculated, removing obsolete language from the *Tariff* that conflicted with the *OA*.

The approved packages now move on to the Members Committee for a final vote on Sept. 17 and a FERC filing in October.

Zonal NSPL Values

Stakeholders by acclamation endorsed deadline changes for adjustments associated with finalizing the zonal network service peak load (NSPL) values in *Manual 14D* and *Manual 27*.

Ray Fernandez, PJM manager for market settlements development, reviewed *updates* to the generator operational requirements in Manual 14D and the Tariff Accounting section of Manual 27. The Manual 27 revisions were endorsed at the Aug. 5 Market Implementation

| © *RTO Insider*

PJM News

Committee meeting, while the related Manual 14D revisions were endorsed at the Aug. 6 Operating Committee meeting.

The revisions are related to the border yearly charge (BYC), the charge for long- and short-term point-to-point transmission service for points of delivery at PJM's border, which goes into effect on Jan. 1 of each year. Fernandez said deadlines in both manuals conflicted with the deadlines of the BYC, including ones for the NSPL verification and zonal adjustments.

In Manual 14D, the behind-the-meter generation business rules had a Dec. 1 deadline for a load-serving entity to request a downward adjustment to its NSPL or obligation peak load. PJM proposed revising the deadline from Dec. 1 to Oct. 31.

Changes in Manual 27 included adding clauses to section 5.2 stipulating adjustments that need to be provided to PJM Market Settlements by Nov. 10. Any adjustments provided after the deadline will not be included in the NSPLs for the next calendar year and won't be used in the BYC calculation.

Risk Management Committee Charter

The newly minted Risk Management Committee is set to meet for the first time in fall after stakeholders approved *revisions* to the Credit Subcommittee charter, expanding its scope to incorporate risk and changing its reporting structure.

Under the revised charter, the renamed subcommittee is also being elevated to a standing committee, reporting to the MRC rather than the MIC.

In her *presentation*, Jen Tribulski, PJM's senior director of member services, said the Credit Subcommittee last met in March 2019 with much of the work around the RTO's credit and risk rules accomplished through the Financial Risk Management Senior Task Force in the wake of the GreenHat Energy default.

Jen Tribulski, PJM | © *RTO Insider*

Tribulski said the task force was established for the specific purpose of overhauling PJM's rules for managing the credit risks of market participants and was not tasked with reviewing credit and risk management issues outside of its limited purposes. (See *PJM Members OK Tighter Credit Rules*.) She said PJM felt it was important to have a committee available to review and work on issues beyond those contemplated by the task force.

Critical Infrastructure Task Force Tabled

Stakeholders withdrew a *problem statement* and *issue charge* set to be voted on to revoke a related issue charge being worked on at special Planning Committee sessions regarding *critical infrastructure stakeholder oversight* after seeing progress.

Greg Poulos, executive director of the Consumer Advocates of the PJM States, and Erik Heinle of the D.C. Office of the People's Counsel had proposed creating a Critical Infrastructure Stakeholder Oversight Senior Task Force under the MRC.

Poulos and Heinle said the task force would have considered whether rule changes are needed to address facility avoidance and mitigation through planning processes and criteria on NERC's critical infrastructure protection (CIP-014-2) list. (See *PJM TO Tariff Filing Stirs up Transparency Concerns*.)

PC special sessions on the topic are currently scheduled through September, with avoidance and mitigation processes and criteria under consideration. (See "Critical Infrastructure Mitigation," *PJM PC/TEAC Briefs: Dec. 12, 2019*.) In proposing the task force, Poulos and Heinle expressed concern progress wasn't being made in the PC special sessions and that TOs can bypass the stakeholder process with filings under Federal Power Act Section 205.

But on Thursday, Poulos said the PC is "in a much better position this month" with "great discussions" among members on mitigation and avoidance of CIP-014 projects. Poulos said PJM and AMP have been putting together "thoughtful packages" to achieve compromises.

Alex Stern, director of RTO strategy for PSEG Services, said he was "a little anxious" of the idea of members being able to make a motion at the MRC if they don't like the direction the stakeholder process is going on an issue.

Poulos said he recognizes stakeholders can vote any way they want to on an issue, but the ability to bring an issue to a vote at the MRC is the right of stakeholders.

Greg Poulos, CAPS | © *RTO Insider*

Cost Development Subcommittee

Glen Boyle of PJM *reviewed* proposed *revisions* to the Cost Development Subcommittee charter during a first read. Boyle said the CDS has been dormant since 2013 and was tasked with developing, reviewing and recommending standard procedures for calculating the costs of products or services.

PJM and the Independent Market Monitor have discussed the need to restart the CDS to address several issues, Boyle said, including Manual 15 clarifications, variable operations and maintenance (VOM), and fuel-cost policy clarifications and educational topics.

The CDS charter has been revised by PJM to report to the MIC instead of the MRC, as most of the issues are handled at the MIC.

The charter changes are scheduled to be voted on at the September MRC meeting.

Consent Agenda

Two issues were endorsed in the consent agenda, with one stakeholder voting no on the agenda items.

First, revisions to Manuals *14A*, *14B* and *14G* in response to FERC's directives on PJM's second Order 845 compliance filing were endorsed. (See "Manual 14 Changes," *PJM PC/TEAC Briefs: July 7, 2020*.)

Second, stakeholders endorsed OA *revisions* to grant TOs access to the Dispatch Interactive Map Application. (See "DIMA Quick Fix Endorsed," *PJM OC Briefs: July 9, 2020*.) ■

— Michael Yoder

SPP Seams Steering Committee Briefs

SPP, MISO Near Potential Joint Projects, None with AECI

SPP has identified a couple potential joint projects with MISO but none with Associated Electric Cooperative Inc., staff told stakeholders Thursday.

The RTOs' coordinated system plan (CSP) study has focused on three options to address a need along the high-wind Iowa-Nebraska border, Neil Robertson, SPP interregional relations senior engineer, said during the Seams Steering Committee's meeting Thursday. Robertson said the RTOs still need to complete work in the "cost estimate realm" and that he expects a "determination" on any jointly funded projects by September.

"I can't project the [CSP's] final determination," he said. The RTOs have conducted three previous joint studies since 2014 but have yet to come up with a project to which both could agree. (See *MISO, SPP Staff Recommend 2020 Joint Study*.)

The 2020 joint CSP with AECI failed to find any projects that provided benefits to both organizations, Robertson said. A final report will be published in a few weeks, he said.

AECI Wolf Creek Agreement Filed with FERC

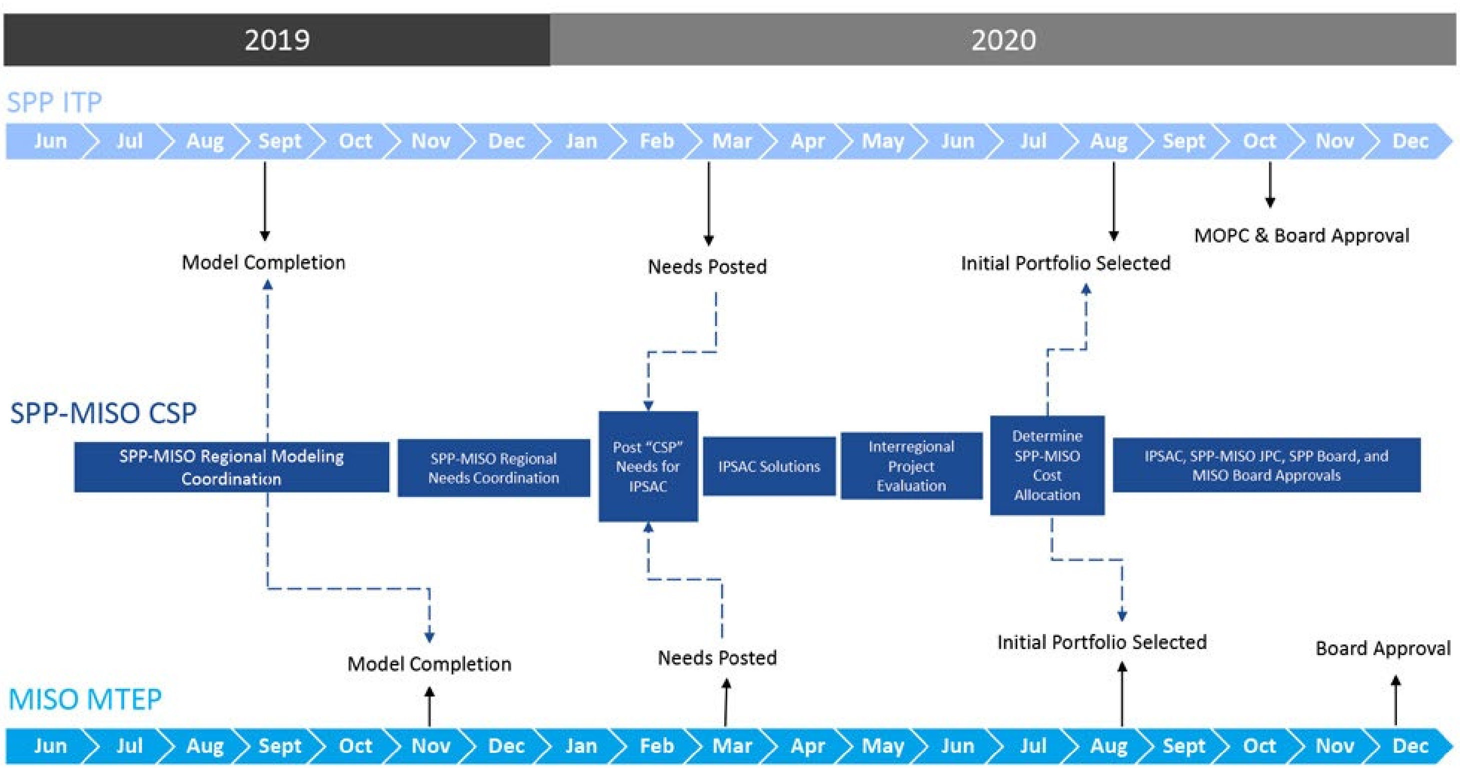
A separate project with AECI, the 345-kV Wolf Creek-Blackberry line in Kansas and Missouri, cleared another hurdle with a completed cost-of-use agreement between the entities and its subsequent filing at FERC, Robertson said. SPP filed the agreement (*ER20-2708*) and associated Tariff revisions (*ER20-2707*) shortly after the SSC meeting, asking for a response within 60 days.

SPP's Board of Directors suspended the project in April while awaiting the completed agreement. Anxious to relieve congestion on the eastern edge of the RTO's footprint, stakeholders in July agreed to not lift the suspension and issue a request for proposals. Once the agreement is filed at FERC, intervenors will have 20 days to file any protests while staff prepares the RFP. (See "Agreement on Competitive Project's Path Forward," *SPP Board of Directors/MC Briefs: July 28, 2020*.)

The project was approved by SPP's board last year and was included in the RTO's *2020 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. The RTO cannot allocate funds to AECI without FERC approval.

SPP Nears $100M in M2M Settlements

SPP has closed in on $100 million in market-to-market (M2M) settlements accrued from



SPP and MISO are on track with their plans for a 2020 coordinated study. | *SPP, MISO*

SPP News

MISO, adding $11.43 million during May and June. That pushed SPP settlements in its favor to $93.85 million since the two neighbors began the process in March 2015.

High wind energy and spring storms led to constraints on temporary and permanent flowgates, with more than 1,500 binding hours during the two months. SPP accrued $5.32 million in settlements in May and $6.11 million in June, the latter being the second highest in a month.

Settlements have been in SPP's favor for the last nine months and 48 of 64 months total. The M2M process allows the RTOs to dispatch electricity on the most economical routes when congestion leads to constrained flowgates.

MISO's Independent Market Monitor in June made several recommendations to improve flows across the seam in its *annual market report*. The recommendations include increased use of automation in the M2M relief requests, SPP's improved day-ahead modeling of MISO's M2M constraints, and MISO's reduction or elimination of its generator shift factor cutoff that limits its relief on M2M constraints. (See *IMM Issues 5 Recs in MISO State of the Market Report*.)

The RTOs' staff will likely assess the recommendations, solicit stakeholder input and share the results before acting on the Monitor's recommendations.

SSC Prepares to Become Seams Advisory Group

Staff assured SSC members, concerned they may lose input responsibilities into revision requests, that the stakeholder group is still very important to the RTO, despite its pending conversion from a committee to an advisory group.

"An advisory group is just a category of groups," said Erin Cathey, senior market design analyst. "Advisory groups have specialized skills and expertise in the area. They have a significant and important impact in many areas of the governing documents. As we identify impacts from a revision request, we will route them to the seams group following the same process tomorrow as we do today."

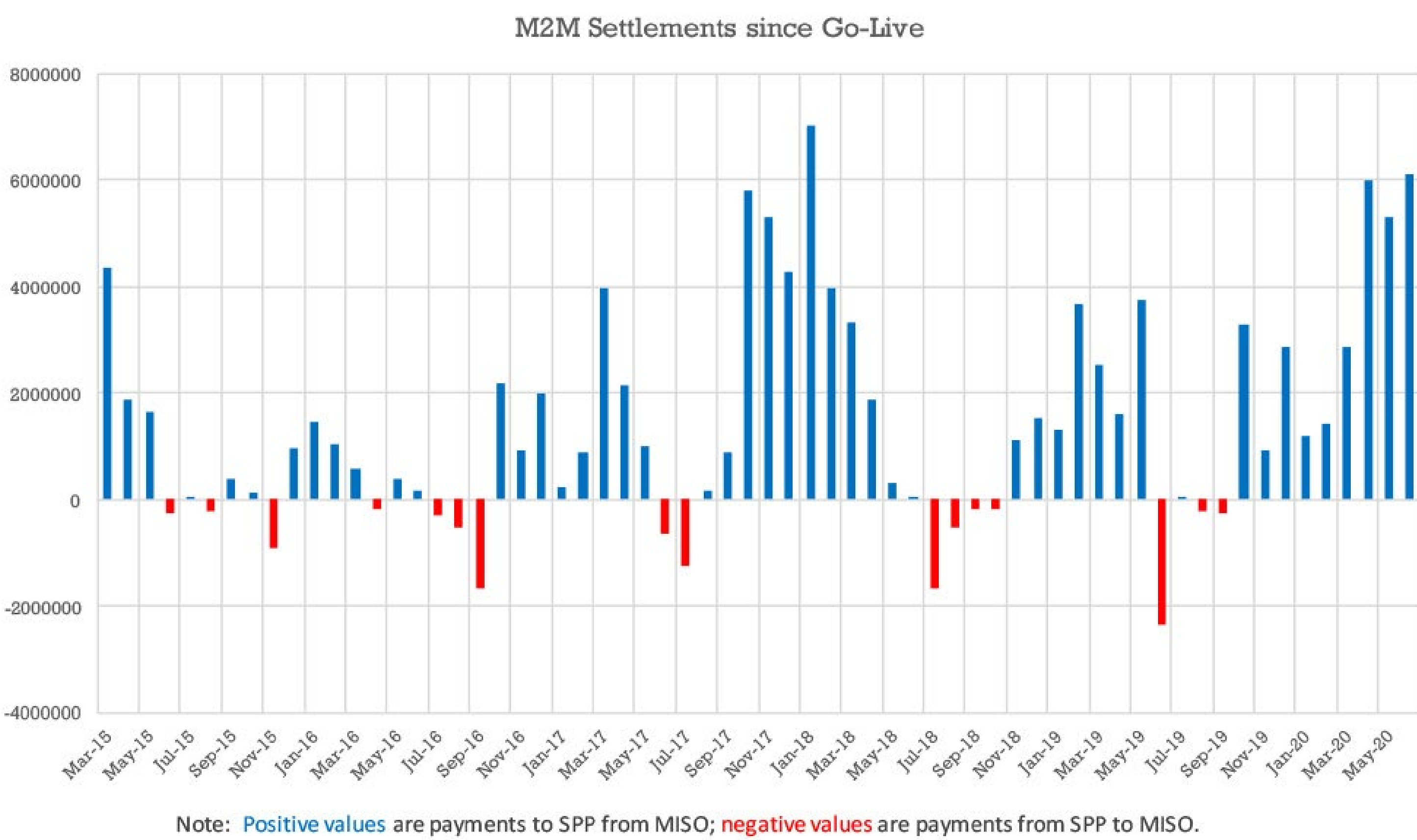
The SSC will become the Seams Advisory Group as part of a reorganization of the Markets and Operations Policy Committee stakeholder groups. The MOPC endorsed the proposed changes in July. (See "Members OK MOPC Reorg, Strategic Roadmap," *SPP MOPC Briefs: July 15-16, 2020*.)

The reorganization is designed to reduce meeting costs and make better use of everyone's time through more virtual meetings. In that respect, the SSC is already ahead of the game.

Clint Savoy, the committee's staff secretary, said, "This year has shown us we can be effective, though we have longer meetings virtually."

The committee is modifying its scope for submission to the Corporate Governance Committee in November. Should the board approve the scope statements and new structure, it will become official early next year. ■

— Tom Kleckner



SPP is nearing $100 million in market-to-market settlements. | *SPP*

SPP News

SPP Readying 2nd Attempt at WEIS Tariff

By Tom Kleckner

MMU Director Keith Collins shares his thoughts on the WEIS market power study. | *SPP*

SPP staff are working feverishly to address FERC and Market Monitoring Unit concerns that threaten the launch of its Western Energy Imbalance Service (WEIS) market.

FERC last month rejected the RTO's proposed Tariff for the market, saying it failed to respect nonparticipants' transmission rights 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*). (See *FERC Rejects SPP's WEIS Tariff*.)

On Aug. 3, SPP's MMU posted a report on a *WEIS market study* that found "high potential" for structural market power. The Monitor concluded that the WEIS presents "significant structural market power concerns" for energy and imbalance energy that should be addressed before its implementation.

SPP's regulatory and legal departments are working to revise the Tariff for another filing in early September. Staff have met with the region's nonparticipants to understand and address their concerns and then fold them into the next filing. They plan to meet with FERC staff in September to lay out a plan for moving forward.

The WEIS working group and executive committee last week passed four revision requests (WRRs) responding to the FERC and MMU issues. Those groups have scheduled two joint meetings this week to hammer out additional WRRs needed to finalize the filing.

Market Design Manager Gary Cate said he is still confident SPP can meet a Feb. 1 deadline for launching the market.

"I think we've put together a really good package and minimized changes to everyone's system involved, and I think we've hit directly at what the FERC's recommendations are. I don't see why we can't move forward," Cate told the Western Markets Executive Committee during its meeting Friday.

David Kelley, SPP | © *RTO Insider*

David Kelley, SPP's director of seams and market design, noted that the commission provided specific guidance to help staff respond to the filing's deficiencies.

"This order was really a good order for us," he said. "When you read through it, it was very complimentary of our efforts and recognized the benefits of markets being developed in the West. I got the sense the commission was encouraging us to continue developing the WEIS market and address the issues they noted in the order.

"We will know where we stand after meeting with FERC in September," Kelley said.

The WMEC and Western Market Working Group's approved revision requests last week included *WRR5*, a response to FERC's assertion that there was a lack of justification for automatic increases to market mitigation thresholds and the MMU's concerns over market power.

SPP based its proposal on its Integrated Marketplace market power mitigation provisions, where it automatically applies mitigation measures to resource offers if the offer exceeds applicable thresholds and fails the market impact test.

The change expands the local market power test to include an assessment of structural market power at the system level. It also "appropriately" mitigates the energy offers when a resource has system-level structural market power and an energy offer curve that exceeds the conduct test threshold, when an impact test has failed for that market interval.

MMU Executive Director Keith Collins said the Monitor "fully supports" WRR5, which borrows from a similar ISO-NE mechanism.

"We think it's a good alternative," he said.

The Western markets governance groups also approved three other WRRs:

- *WRR2*: updates the WEIS protocols to be consistent with SPP's system change process and modifies the emergency change language to clarify that the RTO will notify stakeholders of the change as soon as practicable.
- *WRR3*: aligns the WEIS protocols to the Tariff, and documents the changes for the WRR process.
- *WRR4*: corrects a calculation of the lower operating tolerance for underground residential distribution (URD) and clarifies language expanding URD tolerance during contingency reserve events.

The WEIS currently includes eight members and covers the Western Area Power Administration's Western Area Colorado Missouri and Western Area Upper Great Plains West balancing authority areas. Several other Western utilities are interested in participating as well, SPP has said.

Market participants are currently undergoing structured testing of SPP's upstream systems. They are testing data inputs in certain scenarios to ensure they act as expected. ■

Company Briefs

SPP's Caspary Joins Grid Strategies

Grid Strategies *said* last week that it has added ***Jay Caspary*** to its consulting firm as a vice president. The move is effective Sept. 1.

Caspary has retired from SPP, where he most recently directed research, development and tariff services. He has 40 years of experience in transmission planning, engineering, power system design and deploying grid-improvement technologies, including a one-year stint as a senior policy adviser for the Department of Energy's Office of Electricity Delivery and Energy Reliability.

"In a few short years, Grid Strategies has established itself as the leading consulting firm on bulk power system changes … and I am excited to be part of this innovative team," Caspary told *RTO Insider*. "The time is right to create a shared vision for future grid that will enable markets for clean energy while leveraging proven technologies in a way that will make us all proud."

Earthquake Prompts Inspections at Fermi 2 Nuclear Plant

A 3.2-magnitude earthquake shook the Detroit area last week, and though it did not trigger seismic alarms at DTE Energy's Fermi 2 nuclear plant, the utility said it did safety inspections.

The earthquake occurred at 6:55 p.m. CT Friday off the shoreline of Sterling State Park, according to the U.S. Geological Survey, and about 2 miles from the nuclear plant. DTE spokesman Stephen Tait said the plant followed preplanned inspections and procedures to ensure safety following the activity and that it is in "safe, stable condition."

The Nuclear Regulatory Commission said it will host a previously scheduled virtual meeting on the plant's performance at 5:30 p.m. this Thursday.

More: *The Detroit News*

Judge OKs Tesla Settlement over SolarCity Buyout

A Delaware judge last week approved a $60 million settlement in a shareholder lawsuit challenging Tesla's $2 billion acquisition of SolarCity in 2016. The lawsuit alleged Tesla directors breached fiduciary duties to shareholders by agreeing to buy the struggling solar energy company, which Tesla owner Elon Musk and his cousins co-founded.

The judge also approved $16.8 million in legal fees and expenses requested by the plaintiffs' attorneys, which amounts to roughly 28% of the "derivative settlement," which was made on behalf of the company and will be funded by insurers. A trial with Musk as the lone defendant is set for March 2021.

More: *The Associated Press*

Teslas Accounts for 80% of EVs Sold in Year's First Half

Teslas made up more than 80% of all electric vehicles sold in the first half of 2020, according to data from Buy Shares.

The data showed Americans purchased 87,398 EVs in the first half of this year, 71,375 (81.6%) of which were Teslas. The Model 3 was the most popular vehicle, with 38,314 sold.

More: *CNET*

Lawsuit Says AEP Hurt Investors by Hiding Bribery Scandal Involvement

A class-action lawsuit filed last week by investor Diana Nickerson on behalf of American Electric Power investors against the utility and its executives alleges the company covertly participated in a bribery scandal overseen by former Ohio House Speaker Larry Householder to secure a $1.3 billion ratepayer bailout of two nuclear power plants and help for coal plants.

The lawsuit claims investors who purchased AEP stock between November 2016 and July 2020 were "economically damaged" by the company's involvement with Householder's campaign to pass House Bill 6. It also asserts that because of AEP's support and Householder's efforts, the company's stock price was "artificially inflated," the company "face(d) increased scrutiny," and it became "subject to undisclosed risk of reputational, legal and financial harm."

Empowering Ohio's Economy, a nonprofit funded by AEP, gave a total of $350,000 to two Householder-allied dark-money groups, according to *The Columbus Dispatch*.

More: *Cleveland.com*

Occidental Petroleum to Build CO_2 Removal Plant

Occidental Petroleum's venture capital arm, Oxy Low Carbon Ventures, has formed a company with sustainability-focused private equity firm Rusheen Capital Management to license the direct air capture technology developed by Carbon Engineering. Their goal is to develop the largest facility to capture carbon dioxide out of the atmosphere.

The new company, 1PointFive, will develop the facility in Texas' Permian Basin and aims to capture up to 1 million metric tons of CO_2 a year. The project, which will seek financial backing on the market, will begin construction in 2022.

Captured CO_2 will be stored underground and used to increase pressure in the oil field and speed up production.

More: *Reuters*

Vistra Energy Approved to Build Large Storage Project

The Monterey County Planning Commission in California last week unanimously approved Vistra Energy's proposal to install a 1,200-MW lithium ion battery storage system on a 137.5-acre area at the Dynegy power plant in Moss Landing. The proposal calls for the construction of four two-story buildings, each housing a 300-MW storage unit with associated conversion systems and two substations.

The project is designed to support the state's renewable energy initiatives to increase storage to reduce the loss of alternative energy and provide consistent, reliable energy on demand.

More: *Monterey Herald*

Federal Briefs

14 States Sue Trump Admin over LNG Transportation Rule

Fourteen states and D.C. last week announced they will sue the Trump administration over a new rule that would allow for the transportation of LNG by rail, citing health and safety risks. The rule, which was finalized by the Transportation Department and Pipeline and Hazardous Materials Safety Administration earlier this year, would allow LNG to be transported on rail tank cars. Previously, a special permit was needed.

The lawsuit did not lay out legal arguments, but the plaintiffs plan to argue that the PHMSA failed to evaluate the rule's environmental impacts and does not contain enough safety requirements.

More: *The Hill*

April CO_2 Emissions Lowest in Decades

Monthly U.S. energy-related carbon dioxide emissions fell to 307 million metric tons in April, marking the lowest value in the Energy Information Administration's monthly series for CO_2 emissions that dates back to 1973.

EIA contributed the low total to travel restrictions and other measures taken to mitigate the spread of COVID-19, which marked significant changes in energy consumption and resulted in lower energy-related emissions.

Between March and April, CO_2 emissions from petroleum and coal consumption decreased 25% and 16%, respectively. Emissions from natural gas consumption dropped 17%.

More: *EIA*

FERC Extends Pandemic Emergency Waivers

FERC last week extended two pandemic emergency-related waivers that were to expire on Sept. 1 to Jan. 29, 2021, to "provide continued safety and flexibility."

The commission voted to approve an extension of the waiver of notarization and in-person meeting requirements in open-access tariffs, and extended a waiver of regulations requiring filings with the commission be notarized or supported by sworn declarations.

More: *FERC*

Lawsuit Challenges TVA's Program of 'Never-ending' Contracts

A lawsuit filed last week on behalf of Protect Our Aquifer, Energy Alabama and Appalachian Voices is taking aim at the Tennessee Valley Authority's monopoly status and says new contracts renew automatically and require a 20-year notice to terminate, effectively making them "never-ending." It also claims that TVA failed to analyze and disclose the consequences of its program establishing the new contracts and consider alternatives, as required by the National Environmental Policy Act.

TVA spokesman Scott Brooks said the contracts are long-term partnerships developed at the request of local power company partners and are "completely voluntary." Previously, TVA contracts were in the seven-year range.

The lawsuit asks that the contracts be set aside, and that TVA go through a NEPA process before offering them again. It also asks for the recovery of the plaintiffs' attorney fees and costs.

More: *InsideClimate News*

State Briefs

CALIFORNIA

LS Power Energizes World's Biggest Battery

LS Power last week announced its Gateway Energy Storage project in East Otay Mesa, the biggest battery project in the U.S., can now charge or discharge 230 MWh, making it the largest such project in the world. The company expects it to rise to 250 MWh by the end of the month.

The company launched Gateway earlier this summer at 62.5 MWh. It now exceeds the previous largest battery, the Tesla-supplied, 193-MWh Hornsdale plant in South Australia.

The project reached 200 MW on Aug. 1, and LS Power added 30 MW last week to deliver extra peak power during the Western heat wave.

More: *GreenTech Media*

PG&E Worker Dies Helping with Northern Wildfire Response

An employee of Pacific Gas and Electric died last week while assisting crews responding to a massive wildfire in the northern part of the state.

The worker, who was not identified, was found unresponsive in his vehicle Wednesday in the Gates Canyon area outside Vacaville, according to the Department of Forestry and Fire Protection (Cal Fire). Officials performed CPR before taking the worker to a hospital, where he was pronounced dead.

The worker was clearing infrastructure in the area to assist crews responding to the LNU Lightning Complex fire, according to Cal Fire.

More: *Los Angeles Times*

Trump Issues Wildfire Disaster Declaration

President Trump last week approved a disaster declaration that will funnel federal aid to regions affected by the raging wildfires. The areas include Lake, Napa, San Mateo, Santa Cruz, Solano, Sonoma and Yolo counties.

The state is battling two of the largest fires in its history: the 314,000-acre LNU Lightning Complex in the northern Bay Area and Central Valley, and the 291,000-acre SCU Lightning Complex largely east of San Jose.

More: *The Hill*

COLORADO

Boulder City Council Votes to Put Xcel Agreement on Ballot

The Boulder City Council last week voted 6-2 to ask voters to approve a 20-year franchise agreement with Xcel Energy, which would end the city's 10-year quest to operate its own electric utility, on the ballot in November. A final vote on the matter is set for Sept. 1.

Issues raised against the proposal included not knowing the final cost of the agreement, a lack of trust in the company and the difficulty of restarting municipalization if the agreement doesn't work. Mayor Sam Weaver said the proposal is the best deal he's seen from Xcel.

The agreement would mean modern grid planning for Boulder and a partnership to meet its goals of 100% renewable electricity by 2030, and includes assurances that Xcel would reduce its 2005 carbon emission levels by 80% by 2030. The city would have six chances to opt out.

More: *Daily Camera*

CONNECTICUT

PURA Fines Eversource, UIL over Shared-solar Program

The Public Utilities Regulatory Authority last week fined Eversource Energy and United Illuminating $10,000 each over an "insufficient" rollout of a program called shared solar.

Shared solar allows customers who can't put panels on their roofs to subscribe to a nearby array and get credit on their bills. The legislature passed the program in 2018, requiring utilities to identify eligible customers and automatically enroll them. PURA said it fined the companies because their plans for seeking and enlisting customers in the program "failed to meet the minimum requests" of state regulators and "failed to outline specific plans."

The utilities have until Sept. 30 to refile their plans.

More: *WNPR*

INDIANA

Notre Dame Commits to New I&M Solar Farm

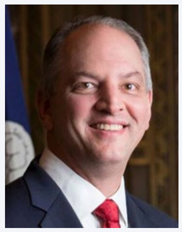
The University of Notre Dame last week committed to purchase clean energy credits equaling 40% of the output from Indiana Michigan Power's (I&M) new $37 million, 22-MW solar farm under construction in St. Joseph County.

I&M said the 200-acre project will be the utility's largest solar plant. Work is expected to be completed in the spring.

More: *Inside Indiana Business*

LOUISIANA

Gov. Edwards Commits to Net-zero Emissions by 2050



Gov. **John Bel Edwards** last week signed two executive orders intended to drive the state toward reducing greenhouse emissions and mitigate the effects of climate change.

One order creates a task force of representatives of government, industry and civic and environmental groups that will recommend strategies, policies and incentives aimed at meeting a goal of a 26 to 28% reduction in greenhouse gases by 2025, a 40 to 50% reduction by 2030 and net-zero by 2050. Recommendations will be due by February 2022, with a detailed plan on how the goals will be met expected a year later.

Edwards' second order formally created the position of chief resilience officer in the governor's office.

More: *The Times-Picayune | The New Orleans Advocate*

NEW JERSEY

Plan for Solar Panels on Farmland Gets Delayed

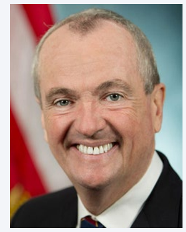
A bill aimed to reverse a policy initiated under former Gov. **Chris Christie** that sought to keep solar projects from being built on agricultural land and other open spaces was held up last week amid signs of a potential policy dispute between lawmakers and the Murphy administration.

The debate reflects competing policy priorities that both sides support: preserving farmland and open space in the nation's most densely populated state, and simultaneously developing a framework to achieve Gov. Phil Murphy's clean-energy goals. Still, both sides agree the state will never achieve Murphy's goal of 34% solar energy by 2050 without larger grid-scale projects.

The legislation drew criticism from the Board of Public Utilities and the Division of Rate Counsel. Senate Environment and Energy Committee Chairman Sen. Bob Smith tabled the bill when it became clear he did not have the votes to release it.

More: *NJ Spotlight*

Utility Shutoff Moratorium Extended to Oct.



Gov. **Phil Murphy** last week announced the state's public utilities have agreed to extend their voluntary moratorium preventing shutoffs to both residential and commercial customers during the COVID-19 pandemic until Oct. 15.

The utilities will offer residential and commercial customers a flexible and extended deferred payment agreement (DPA) of 12 to 14 months. Customers may start to receive shutoff notices in September, but should that occur, they are to contact the utility as soon as possible prior to Oct. 15 to make arrangements to continue their utility service, explore enrolling in a DPA and learn about what other assistance programs might be available.

More: *Office of Emergency Management*

NORTH CAROLINA

DEQ OKs Plan to Close Weatherspoon Plant

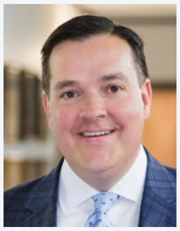
The Department of Environmental Quality last week approved a plan to close the Weatherspoon Power Plant in Lumberton and remove coal ash from the site. The plant was one of six facilities owned by Duke Energy for which closure plans were approved.

The order requires Duke to excavate more than 80 million tons of coal ash from open, unlined impoundments at several locations and place the excavated coal ash in on-site lined landfills. About 700,000 tons of coal ash have already been excavated from Weatherspoon with about 1.5 million tons left.

More: *The Robesonian*

NORTH DAKOTA

State to Proceed with Dakota Access Protest Lawsuit



U.S. District Court Judge **Daniel Traynor** partly denied the federal government's motions to dismiss a lawsuit that asks it to pay $38 million in costs the state incurred to respond to protests over the Dakota Access pipeline in 2016 and 2017.

The state sued the government in July 2019 to recoup costs arising from months of protests related to the construction of the Energy Transfer oil pipeline and claimed the U.S. Army Corps of Engineers enabled the protests and failed to maintain order.

The lawsuit says the state had to pay for the removal of 21.4 million pounds of trash and debris left behind by the protesters.

More: *Bloomberg Law*

OHIO

Ottawa, Lake County Leaders Push Back on HB 6 Repeal

Ottawa and Lake county officials last week pushed back on attempts to repeal House Bill 6, the 2019 act that provided a massive bailout for the Davis-Besse and Perry nuclear power plants.

The six county commissioners also co-signed a joint statement to Gov. Mike DeWine, Senate President Larry Obhof and House Speaker Robert Cupp, urging them to reform and replace the bill rather than repeal it without plans to pass a modified substitute. They cited the likelihood of mass layoffs at the plants if the bailout is rescinded.

House Bill 6 imposed a new charge on electricity bills to help save the Energy Harbor nuclear plants and two coal-fired plants owned by Ohio Valley Electric Corp. The bill also rolled back renewable energy and energy efficiency investment mandates.

More: *The Blade*

VIRGINIA

Bill Aims to Block Pipeline Worker Surge

Del. Chris Hurst last week filed a bill that would require any employer hiring a crew of 50 or more temporary workers during the COVID-19 pandemic to receive approval from the commissioner of labor and industry. The bill would also require such an employer to participate in one of the state's Voluntary Protection Programs, which oversee voluntary worker safety and health management systems that "exceed basic compliance with occupational safety and health laws and regulations."

The bill would complicate Mountain Valley Pipeline's plans to deploy 4,000 workers to resume work that has been stalled since October 2019. Following MVP's announcement to deploy the workers, 22 Democratic lawmakers sent a letter to Gov. Ralph Northam and others asking them to "do all in your power to stop MVP from proceeding with construction at any point during the COVID-19 pandemic."

More: *Virginia Mercury*

WISCONSIN

Alliant Customers to Get 1-Year Rate Freeze

The Public Service Commission last week unanimously approved a plan to freeze electricity and natural gas rates next year for Alliant Energy customers while increasing company revenue.

Under the deal, Alliant will retain fuel and tax savings that would normally be returned to customers to provide about $32 million in additional revenue for its investment in the 150-MW Kosuth Wind Farm. The utility would use another $7 million in savings from the 2017 federal tax reform and create a "regulatory asset" to cover $15 million in revenue related to the company's expansion of natural gas service. The company will be able to recover the $8 million difference, with interest, in future rates.

The proposal received conditional approval from consumer advocates but raised objections from environmental groups who argued Alliant was essentially planning a future rate increase under the guise of a pandemic response. However, the commission agreed state law does not require a public hearing if rates are not affected.

More: *Wisconsin State Journal*

PSC Extends Shutoff Ban

The Public Service Commission last week voted 2-1 to continue a ban on utility disconnections because of the COVID-19 pandemic until Oct. 1.

Almost 1.4 million households (32.9%) were behind on their bills in July and owed nearly $229 million, according to the PSC's survey of 200 utilities. The PSC will discuss the moratorium again on Sept. 17.

More: *Wisconsin State Journal*

WYOMING

Senators Host Carbon Capture Field Hearing at ITC

The U.S. Senate Environment and Public Works Committee held a hearing last week at the Integrated Test Center (ITC), located on the site of the Dry Fork Station power plant. The ITC is one of the world's only utility-scale carbon capture laboratories attached directly to a coal facility.

Committee Chair John Barrasso initiated the field hearing to promote investments in energy innovations, with an eye toward commercializing carbon capture in the state.

The ITC offers eight carbon capture testing pads for researchers. Industrial ducts from the neighboring power plant transport about 5% of produced flue gas (a byproduct of burning coal) to the testing pads. Researchers then attempt to separate the carbon dioxide for other uses.

More: *Casper Star-Tribune*