RTO Insider

Your Eyes and Ears on the Organized Electric Markets

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Energy Groups Quick to Praise Infrastructure Bill Passage

Energy Provisions Provide Billions for Efficiency, Transmission, Battery Supply Chains

By K Kaufmann

The House of Representatives' Friday night passage of the bipartisan Infrastructure Investment and Jobs Act (*H.R. 3684*) quickly set off a chorus of praise from clean energy groups and equally fervent calls for both of houses of Congress to finish the job by passing Democrats' $1.75 trillion budget package, the Build Back Better budget bill.

Parsing the $1.2 trillion in the infrastructure bill, many of the groups zeroed in on the specific provisions and programs for which they had lobbied hard during negotiations in the House and Senate.

A statement from the Alliance to Save Energy (ASE), for example, included a fact sheet with a detailed listing of the bill's energy efficiency provisions that it had supported, such as Section 40502's allocation of $2.5 billion over five years for commercial and residential energy audits, with up to 25% going to low-income homeowners. Section 40503, also supported by the alliance, follows up with $40 million over five years for energy auditor training programs.

"While at times the Washington gridlock can feel insurmountable, [Friday's] votes show that Congress still has the keys," ASE President Paula Glover said. "This is a moment to celebrate: lawmakers saying 'yes' to a more efficient energy future, 'yes' to a more consumer-friendly energy system and 'yes' to ta robust clean energy workforce."

But Glover also pledged continued action on Build Back Better, to ensure "the final version fully recognizes that efficiency is the fastest, most cost-effective method to decarbonize our economy." ASE is pushing for restoration of a tax credit to help homeowners pay for

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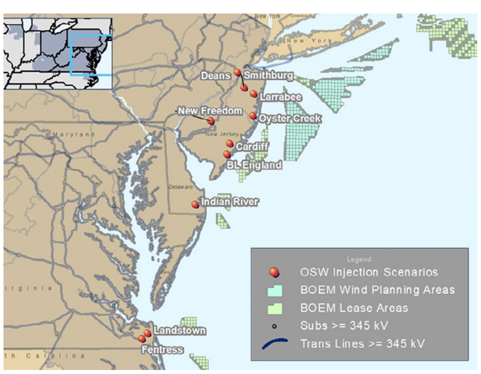
Castor: House Democrats '100% United' on Clean Energy Transition (p.3)

Northeast RTOs Asked to Run Offshore Tx Studies

By Michael Kuser

A group of environmentalists and clean energy industry proponents have asked RTOs in the Northeast to conduct an interregional offshore wind transmission study for two distinct regions off the East Coast.

The Clean Energy Advocates presented their *proposal* at the joint NYISO/PJM/ISO-NE Interregional Planning Stakeholder Advisory Committee (IPSAC) meeting late last month, pushing the need for a study that examines the costs and benefits of an interregional HVDC transmission network for New York and New Jersey, as well as for the line of offshore wind projects running from Massachusetts to North Carolina.



| PJM

"States are very focused on meeting their internal state goals, and regions are focused on their regions, which is fine, but it doesn't seem like anyone is talking about this mythical transmission grid ... and how all this would work," Cullen Howe of the Natural Resources Defense Council, part of the group, told *RTO Insider*.

The group also includes the Sustainable FERC Project, Americans for a Clean Energy Grid, American Clean Power Association, Sierra Club, Advanced Energy Economy, Union

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CPUC Approves More Gas at Aliso Canyon

Winter Reliability Concerns Drive Controversial Decision

By Hudson Sangree

Concerned about a shortage of natural gas this winter, the California Public Utilities Commission on Thursday made the controversial decision to increase the maximum amount of gas stored at the troubled Aliso Canyon underground facility by more than 7 Bcf.

The unanimous *decision* came after nearly two hours of public testimony, much of it emotional, from residents who live near the site of one of the worst methane leaks in U.S. history. From October 2015 to February 2016, a ruptured pipe at the SS-25 well *spewed* more than 100,000 tons of natural

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In this week's issue

ACORE Grid Forum

Castor: House Democrats '100% United' on Clean Energy Transition

ACORE Grid Forum Looks at Gaps and Next Steps for ITCs, Grid Planning

By K Kaufmann

Democratic losses in Virginia, the defeat of a transmission project in Maine and the fates of the bipartisan infrastructure package and $1.75 trillion budget reconciliation bill in Congress were top of mind in the opening sessions of the American Council on Renewable Energy (ACORE) Grid Forum on Wednesday.

Speaking with ACORE CEO Greg Wetstone, Rep. Kathy Castor (D-Fla.), chair of the House Select Committee on the Climate Crisis, called the election results a "wake-up call" as potent as the U.N.'s recent "code red" climate assessment report. Released in August, the report warned the world is running out of time to avoid the worst impacts of climate change. (See *Too Late to Stop Climate Change, UN Report Says*.)

Castor acknowledged the clock may also be ticking on congressional Democrats. "I think there's a great frustration all across the country with the fact that this negotiation has gone on too long. They don't really understand the vagaries of a 50-50 Senate," she said, referring to ongoing tensions between progressive and moderate Democrats in both the Senate and House of Representatives.

At the same time, she remained optimistic that both bills will be passed, saying the House Democratic Caucus is "100% united on the need to move to clean energy and do it swiftly."

Castor also stressed the importance of bill provisions that will support better grid planning, encouraging "power markets to do better on cooperating on resilience" and the Department of Energy "and FERC to be much more forward-leaning to avoid congestion and political roadblocks."

While the critical role transmission must play in grid decarbonization and economy-wide emissions reduction is the key theme at the two-day event, politics were a constant, tangential concern. Industry hopes for passage of the bills were reflected in a panel discussion on infrastructure priorities, which focused on the incremental process of implementation that will lie ahead — and the problems neither bill may be able to solve, as the U.S. seeks to decarbonize its grid by President Biden's target of 2035.

"What's at the forefront of my mind right now is how are all pieces fitting together, and what are the policies beyond just at a congressional level, when we get to [the] regulatory or even state level," said Kevin Gresham, senior vice president of government relations for developer RWE Renewables America. "Where do we need to focus our intentions and work over the next really short period of time to get this underway."

For Alex Daberko, managing director at infrastructure investor Starwood Energy, obstacles to what he called project "feasibility" are now the biggest challenge.

"Developing utility-scale, renewables has got-

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ACORE Grid Forum

ten more challenging, not less," Daberko said, pointing to the three-year timeline for project development that "is sort of a rule of thumb" for wind and solar projects.

"When you can't count on the timeline or the results from the interconnection study process, then that makes it that much harder," he said. "And then when you're juggling tax policies that changed four times during that three-year window and also face inflation and other things, it's really hard to keep all the balls in the air, which is the key to successful development."

Procuring clean energy for Walmart's 5,300 U.S. stores is all about the three Rs, said Steve Chriss, the discount retailer's director of energy services. "How does it benefit renewables? How does it benefit reliability? How does it benefit resilience?"

He sees expansion of transmission and distribution systems as critical for Walmart to hit its own target of running its stores on 100% renewable energy by 2035.

"We're going to require more electricity," Chriss said. "That electricity needs to be carbon free, and really the power quality needs to be extremely high. So that means that we need reliability when things are going well. We need resilience when things aren't going well. And the infrastructure buildout is really critical to meet all of these needs."

And, he added, "It's not only about interconnection; it's about driving deliverability to load."

The ITC Compromise

With the Clean Electricity Performance Program — that would have paid utilities for cutting their emissions — forced out of the reconciliation bill, industry attention has turned to exactly what kind of tax credits will be in the final package and what they can accomplish.

Daberko said a stable 10-year extension of the solar ITC could unleash pent-up demand and market growth for projects that may have stalled due to the COVID-19 pandemic.

"There are a lot of people that have had to go back to offtakers with [power purchase agreements] that were negotiated a year or two ago, and the world looked a lot different," he said. "This 10-year extension could be the bridge that makes those projects whole again. So, I think from our side and from the OEMs perspective, they expect 2022-2023 to be pretty monumental years for deployment if this passes."

But Christina Hayes, vice president at Berkshire Hathaway Energy, said the transmission investment tax credits in the reconciliation package may have limited impact. They are "really targeted to projects that need a little bit more to kind of get over the hump," she said, referring to an *ACORE report* identifying 22 shovel-ready projects that would benefit from a transmission ITC. (See *Transmission ITC Could Add 20 GW of New Capacity to Grid*.)

She was more positive about a prospective compromise between the House and Senate, which would set up a two-phase approach to tax credits. If enacted, clean energy ITCs would remain technology-specific — separate ITCs for solar, standalone storage and transmission, among others — for five years, the House approach. Credits would then become technology-neutral, based on emission reductions, an approach supported by Sen. Ron Wyden (D-Ore.).

"They got the order correct," Hayes said. "Get everything started in kind of a full-throated way with the House approach, and then transition to Sen. Wyden's approach to make sure that the incentives go on until the goal is met … to make sure that we are truly keeping an eye toward what the goal is. We're not deploying resources so we can trade RECs [renewable energy credits]. We're deploying resources so that we can serve customers with clean energy and retire the less-clean energy."

Filling the Gaps

But beyond the transmission ITC and other transmission supports in the reconciliation and infrastructure bills, crucial gaps remain in the development of transmission planning and buildout, according to Castor and others at the forum.

Castor pointed to the *Efficient Grid Interconnection Act* that she introduced in June, which would have required FERC to allocate costs for transmission upgrades more broadly.

"Many of the network upgrades required to connect new renewable energy and storage projects benefit all customers," Castor said. "So cost allocation should reflect that consideration of environmental benefits, including reduced carbon pollution. Conventional air pollution should be considered, and we want to encourage the use of grid-enhancing technologies to reduce the cost of network upgrades."

While the bill did not make it into either the infrastructure or reconciliation bill, Castor sees FERC's current proceeding on grid planning and cost allocation, the Advanced Notice on Proposed Rule Making, as another avenue to address these issues. (See *Transmission Industry Hoping for Landmark Order(s) out of FERC ANOPR*.)

"Our view has to be broader and more forward-looking in order to really put [transmission planning] together in a way that makes sense so we can more efficiently expand the grid … which benefits customers because it is the efficient way to do it," said Bill Parsons of ACORE, who moderated the panel.

Gresham and Daberko cautioned that stakeholder buy-in at multiple levels will be needed to develop and execute any new processes.

At the state level, getting projects approved remains a major challenge, Gresham said. "How do you get it through local commissions and by landowners? Because ultimately, regardless of the policy and player who has authority, you still have to do a really good job of stakeholder engagement," he said. "You still have to get local buy-in and figure out ways to really build that community support for a project."

Daberko cautioned that big rule changes or new compliance requirements tend "to hit the brakes on deployment, because you know, every bank, every potential investor has to get comfortable with those rules and making sure that they don't have a discontinuity in returns if they miss on some new requirement that's not fully understood."

For Walmart's Chriss, another gap that needs to be addressed is the role of co-ops and municipal utilities in grid planning. Walmart gets its power from just under 1,000 utilities, with a majority of it coming from big investor-owned utilities. But, he said, "there are a lot of munis and co-ops [that] don't actually own or are indirectly responsible for the procurement of generation."

Small public and cooperative utilities are more sensitive to the price impacts of transitioning to clean energy because they have fewer customers, Chriss said. "There needs to be concerted efforts to find paths forward to help transition these organizations.

"It's really about transitioning the entire grid to be decarbonized, and transmission is just a piece of that," he said. "At the end of the day, we all want to be served by clean energy around the clock, all the time and that's everybody; so, it just becomes the new normal. The goal of corporate procurement should be to get everyone to a point where we no longer need to do corporate procurement because the steady state of the system is clean." ■

ACORE Grid Forum

DERs and Clean, Firm Power Needed to Decarbonize Grid

ACORE Grid Forum Looks at How to Drive Innovation, Commercialization for Both

By K Kaufmann

Two key components of the decarbonized grid of the future — distributed energy resources, and the clean, firm power needed to back them up — were the topics of two panels at the two-day American Council on Renewable Energy Grid Forum.

The central question for Wednesday's panel on integrating DERs — both wind, solar, storage and demand response, and their various "hybrid" combinations — across power markets was what's needed to bring them on the grid in a way that maximizes their multiple value streams while ensuring system reliability.

Taking in a 20-year horizon, MISO is "looking at various ratios of wind to solar to DERs to storage and hybrids," said Renuka Chatterjee, the grid operator's executive director of system operations. "As we look at those futures, the thing that we are learning is it's pretty similar. So, to the extent you can see these resources as similar in the sense that they provide a service, be it energy or ancillary services, you get a lot of common ground."

In the example of storage, Chatterjee said, MISO treats storage the same as it treats oil or gas, letting "storage manage its own fuel, which is the battery. ... So, that allows us to key in [a] market signal that is consistent and unique while enabling the features of these new resources."

But Jamie Link, vice president for solar and storage at EDF Renewables North America, said such a technology-neutral approach may not be the best for optimizing the value of utility-scale solar and storage projects. With more than 2 GWh of storage under contract in the West, EDF is "quite closely" following CAISO's implementation of storage integration, Link said.

"CAISO's resource adequacy market is a bilateral capacity market, which is very strong both on the system and local level in providing value to storage, and storage can also capture value in the energy and ancillary markets in California," she said.

She pointed to CAISO's *aggregate capacity constraint* (ACC) proposal as a model for other grid operators to follow, as increasing amounts of solar, storage and other DERs come online. The proposed rule would allow the ISO to set multiple capacity constraints for co-located solar and storage projects sharing a common interconnection point, so that output from any one project does not exceed the limits of its interconnection agreement.

"So, instead of the project owner having to worry about making sure a dispatch doesn't violate their contract and having to make a decision on whether to be available, those two things are synched up," she said.

CAISO submitted the ACC proposal to FERC in September (*ER21-2853*).

Leveraging the value of DERs at the residential level is even more complex, said Suzanne Leta, head of policy for SunPower. "There is a fundamental right when it comes to distributed technologies, which is consumer choice," she said. "But in order to enable that choice, we have to have the policy tools in place and the incentives in place for customers to take that leap."

For example, Leta said, while only 3% of U.S. homeowners have rooftop solar, and only 2% of all car sales are electric vehicles, 40% of EV drivers have rooftop solar. "There's this automatic connection on the customer end about the relationship between these technologies, and we have to transfer that into getting the rules in place, so the regulators are able to value them in the same way that customers are," she said.

Allowing Failure and Positive Collisions

The forum's closing panel on Thursday looked at what many in the cleantech sector believe will be essential for decarbonizing the U.S. grid by President Biden's target of 2035: the emerging and still-to-be-developed technologies that can provide clean dispatchable power.

But Debra Lew, associate director of the Energy Systems Integration Group, an educational organization, said as levels of renewables on the grid increase, the real need on a day-to-day basis will be flexibility to balance out intermittent wind and solar.

She believes demand-side management is the low-hanging fruit here. "We can do tons of stuff on the demand side, especially today in the advent of electric vehicle charging and [smart] thermostats," she said.

Building out the grid to allow for cross-region aggregation is another must-have. "Imagine

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having solar in the Southwest shipped over to the East to help provide for peak hours, or wind from the Midwest being shipped over to the West. There's a lot you can do with aggregation by building out more transmission."

The outer edge of flexibility — the days or weeks when sun and wind power may not be available — is where other technologies, such as long-duration storage, come in, though they face considerable obstacles to commercialization, said Thomas Jarvi, director of defense contractor Lockheed Martin's flow battery program. The company has spent several years developing its new GridStar flow battery, which is in the final stages of verification testing, he said.

Technology developers need "to think about kind of the transactional end state: Who are their customers, and what are their contract considerations? And what does that transaction look like?" Jarvi said. "What are the customers' buying factors, risk considerations? Can you buy down risk by virtue of government incentives, rate structures, market structures and so forth?"

The investment needed to develop such new technologies is yet another obstacle. While capital markets are "flush with money," said Lee J. Peterson, senior manager at cleantech investment banker CohnReznick, tax equity markets are still hesitant to invest in emerging products and processes.

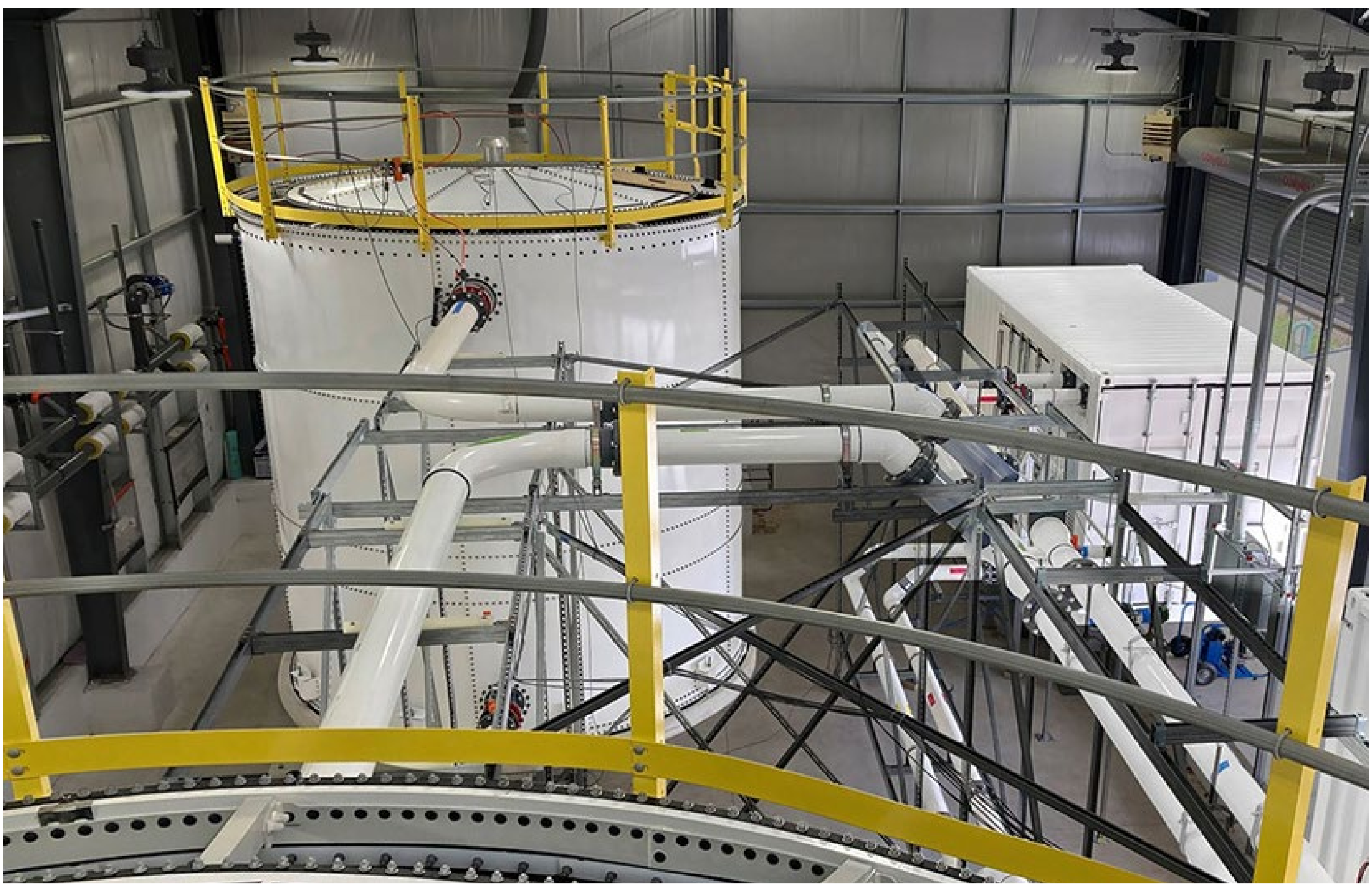
"The comfort level with wind and solar is so large that to get tax equity interested in something other than wind or solar is really a challenge," Peterson said.

His solution is "total optimization of the U.S. tax code for renewables and clean energy in particular," he said. "I can go through the code and find you a dozen or more little ... 'glitches' or stops [that] are really holding back the clean energy economy."

The federal government also needs to play a more active, "first mover" role in de-risking new technologies to help them scale and get to market, Jarvi said. "Other governments understand the implementation of early technology as a key role for the government ... because we're competing in energy technology, always, against massive incumbencies that have volumes baked in already."

Adria Wilson, U.S. policy and advocacy manager at Bill Gates' cleantech venture group Breakthrough Energy, pointed to funding in the newly passed bipartisan infrastructure bill for an Office of Clean Energy Demonstrations in the Department of Energy as a step toward that more active role. But, she said, "there should be a more acceptable culture for the government's projects to fail. I wouldn't want them all to fail, but I think we would want them to be taking risks and creating knowledge that stakeholders and private industry could use to build on."

She called for government "convening with people who are more active in the grid space or other sectors who really know what the market needs are. If you can create moments of collision, positive collision between those two groups, it can help direct the flow of innovation funding in a more productive way." ■



Lockheed Martin is testing the first commercial model of its GridStar flow battery at its research facility in Andover, Mass. | *Lockheed Martin*

ACORE Grid Forum

Overheard at ACORE Grid Forum 2021

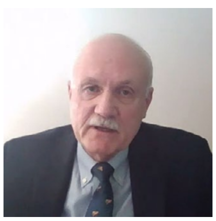
| *ACORE*

The American Council on Renewable Energy held its annual Grid Forum over two days last week. As was the case last year, it was a completely virtual event because of the ongoing COVID-19 pandemic.

The first day of the event, Wednesday, focused on infrastructure policy, transmission planning and energy markets, while Thursday featured discussions on the Biden administration's agenda.

RTO Insider had coverage of much of the first day last week. (See related stories, *Castor: House Democrats '100% United' on Clean Energy Transition* and *DERs and Clean, Firm Power Needed to Decarbonize Grid*.) Here's more of what we heard.

Christie: Tech Outpacing Regulatory Structures


FERC Commissioner Mark Christie | *ACORE*

FERC Commissioner Mark Christie on Wednesday compared the transition to clean resources in the electricity industry to the transition to mobile devices in telecommunications.

The former chair of the Virginia State Corporation Commission, Christie also taught regulatory law at the University of Virginia School of Law. Every year he would ask his students how many of them had a landline telephone, and every year fewer of them would raise their hands, until the last couple of years, during which not one hand would go up.

But the very last year he taught, one student did raise their hand.

"'So you have a land line?'" Christie said he asked. "And the student said, 'Well, what is a land line?'"

Regulating the telephone industry is very similar to regulating electric utilities, going by Christie's description: Smaller companies would file complaints against the incumbent utilities because they were not interconnecting their services. Meanwhile, the utilities need to file rate cases with the state commission for approval.

By the end of his career at the SCC, however, the commission had not reviewed a telephone utility's rate case in years. "The law hadn't changed; the technology had changed," he said. "Wireless technology eliminated" the natural, networked monopolies held by telephone utilities. "And it didn't happen because of smart regulators. It happened because smart engineers in a lab figured out how to transmit [voice data] wirelessly on a mass scale at a cost that consumers could afford."

Distributed energy resources — particularly battery storage combined with rooftop solar — could do the same thing in the electricity space. Disputes over net metering rates would "all go away," Christie said.

"These are the kinds of technologies [that] I'm really optimistic will be transformative. And the challenge is to make sure the regulatory structures are either not behind or not ahead but try to get a rational connection to this transformational technology that I know we're going to see."

ANOPR

Rob Gramlich, president of Grid Strategies, moderated a panel on FERC's Advance Notice of Proposed Rulemaking on transmission planning.

The panelists reiterated a consensus among many commenters in the ANOPR docket that transmission planning in the U.S. is reactive to generator interconnection requests, the queues for which are backlogged because transmission construction is not keeping up. The ANOPR presents an opportunity for FERC to create a forward-looking approach, they said. (See *Transmission Industry Hoping for Landmark Order(s) out of FERC ANOPR*.)

"We're not really planning for the future now, which sort of raises [the question of] why do we even call it transmission 'planning' if it's not about the future generation," Gramlich said.

He asked Danielle Fidler, senior attorney with Earthjustice, how she would respond if the D.C. Circuit Court of Appeals questions FERC's authority "to require these plans and allocate these costs so broadly" under a potential final rule. "Where does that come from?"

"Congress in 1935," Fidler responded laughing. "The Federal Power Act gives FERC really broad authority ... and not just authority but obligation to regulate the transmission system. ... So in our view, FERC not only should act; it must act."

An attendee asked about the timeline of the proceeding, specifically whether the commission would wait for the findings of a joint task force with the National Association of Regulatory Utility Commissioners.

Elizabeth Salerno, FERC's lead for transmission and technology initiatives, could not say when the commission would act, but she did say that "there's a sense of urgency to start chipping away at the block. The scope of the ANOPR is huge. I think it's possible we can't solve all this in one go. There is a consideration of [if we] try to break these up into pieces and tackle them in a logical order. I'm not sure that's how we'll go, but I think that option is on the table."

Gramlich concluded the panel by speaking to the high expectations of the transmission

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industry for the proceeding. "I spent a couple years of my life on another major rulemaking that never got finalized, so the last thing I want is for all this work to go in" and nothing to come out of it, he said.

Western RTO, SEEM Face Headwinds

A panel Wednesday devoted to the expansion of wholesale markets in the West and the Southeast shared their thoughts on the possibility of future RTOs but had few answers.

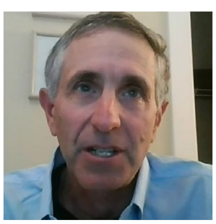
Rebecca Wagner, Wagner Consultants | *ACORE*

Consultant Rebecca Wagner, a former member of the Nevada Public Utilities Commission, noted the alphabet soup of Western markets and organizations, including CAISO's EIM and proposed EDAM, SPP's WEIS market and RTO West, the Northwest Power Pool's WRAP and the Western Markets Exploratory Group (WMEG). (See *Western Utilities to Explore Market Options*.)

"There's always something going on in the West," she said. "There's a lot of places to plug in to."

Wagner said she hopes that, given Western states' climate and clean-energy policies, a clean, reliable and affordable grid of the future can be built that unlocks resource diversity and maximizes customer benefits.

"There's a lot of movement. I'm not sure how it's going to shake out," she said.



Colorado PUC Chair Eric Blank | *ACORE*

Colorado Public Utilities Commission Chair Eric Blank said an incremental approach makes the most sense for his state in the near term. The legislature has directed the state's utilities to join an RTO by 2030 — similar to Nevada legislation — and a regulatory study found that participation in a regional market could yield a 5% cost reduction off $6 billion in revenues, or about $300 million a year, he said.

"There are significant unresolved concerns with RTOs: struggles to ration rare interconnects for resources; fights over cost allocation limiting new transmission; challenging governance structures," Blank said, pointing to SPP's four-year backlog in its generator interconnection queue. "For us, we need to see either CAISO's governance improve or SPP solve its interconnection and cost allocation problems."

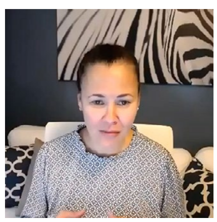
The Southern Alliance for Clean Energy's Maggie Shober said her organization has issues with the proposed *Southeast Energy Exchange Market* agreement, which went into effect after FERC deadlocked over its approval. (See *SEEM to Move Ahead, Minus FERC Approval*.)

She said SEEM is "closer to a bilateral market than anything else," lacks transparency and is not open to independent power producers.

"It's being pitched as a software upgrade, rather than physically calling people on the phone," she said. "It's not a stepping-stone to competition like we're seeing in Nevada and Colorado."

In a *report* on market design and the Southeast, ACORE said, "Absent many traditional market benefits, SEEM is not necessarily a step toward a wholesale power market, but its introduction provides a helpful lens through which to assess energy market design and the Southeast."

Biden's Agenda



Kelly Speakes-Backman, DOE | *ACORE*

On Thursday, Kelly Speakes-Backman, principal deputy assistant secretary for the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) spoke with ACORE CEO Gregory Wetstone about the Biden administration's clean energy goals.

Speakes-Backman, previously CEO of the Energy Storage Association, oversees her office's $2.8 billion portfolio of research and development, demonstration and deployment activities in energy efficiency, renewable energy, and sustainable transportation.

"We're focused on supporting President Biden's clean energy goals of ... achieving a carbon-free electric sector by 2035 and [a] clean-energy economy with net-zero emissions no later than 2050. ...

"President Biden placed this particular goal at the center of his agenda, and we know that we are kind of the tip of the spear, if you will, for that. So in order to really sort of support that, in driving research and development, but even more so the demonstration and the deployment of these technologies, we're really underscoring the fact that this is going to create jobs and economic opportunity. Yes, the climate crisis is an enormous challenge. ... But we also see this as a huge opportunity to create millions of good-paying, middle-class jobs, to ensure that there's clean, affordable, reliable energy options for all Americans."

Environmental Justice

Thursday's first panel, "Centering Environmental Justice in the 21st Century Grid," dealt with the impact of grid investments on low- and moderate-income communities.

Yvonne McIntyre, NRDC | *ACORE*

Yvonne McIntyre, director of federal electricity and utility policy for the Natural Resource Defense Council, moderated a panel that included Jahi Wise, senior adviser for climate policy and finance in the White House Office of Domestic Climate Policy.

McIntyre asked Wise about Biden's executive orders to implement his *Justice40 Initiative*, intended to ensure federal agencies work with state and local governments to "make good on President Biden's promise to deliver at least 40% of the overall benefits from federal investments in climate and clean energy to disadvantaged communities," according to the White House.

"It's historic in its scope and scale and trying to orient the federal government around equitable investment in climate and clean energy infrastructure," Wise said. "Folks who are in this space for a while know that's not the way that things have historically gone, so the intentionality there is unprecedented."

About 20 federal government programs are covered by the initiative, he said, "and right now those programs are working through their stakeholder engagement plan, their initial implementation and kind of paving the way for the rest of the federal government to begin this investment process. And so we expect in the next few months to see even more programs join that cohort but also more from the initial set of programs."

He said that Biden "directed a number of White House components and agencies to put out environmental justice scorecards, and so those scorecards are supposed to be like our first accounting of whether or not we're actually meeting our targets on environmental justice as a component of climate policy. And that will look at everything from Justice40 to the different environmental justice offices at the agencies. So there's kind of a really robust, whole-of-government effort on this topic." ■

— Michael Brooks, Tom Kleckner and Hudson Sangree

FERC/Federal News

Senate Energy Committee Advances Phillips

By Michael Brooks

The Senate Energy and Natural Resources Committee on Nov. 2 unanimously voted to advance D.C. Public Service Commission Chair Willie Phillips' nomination to FERC to the Senate floor.

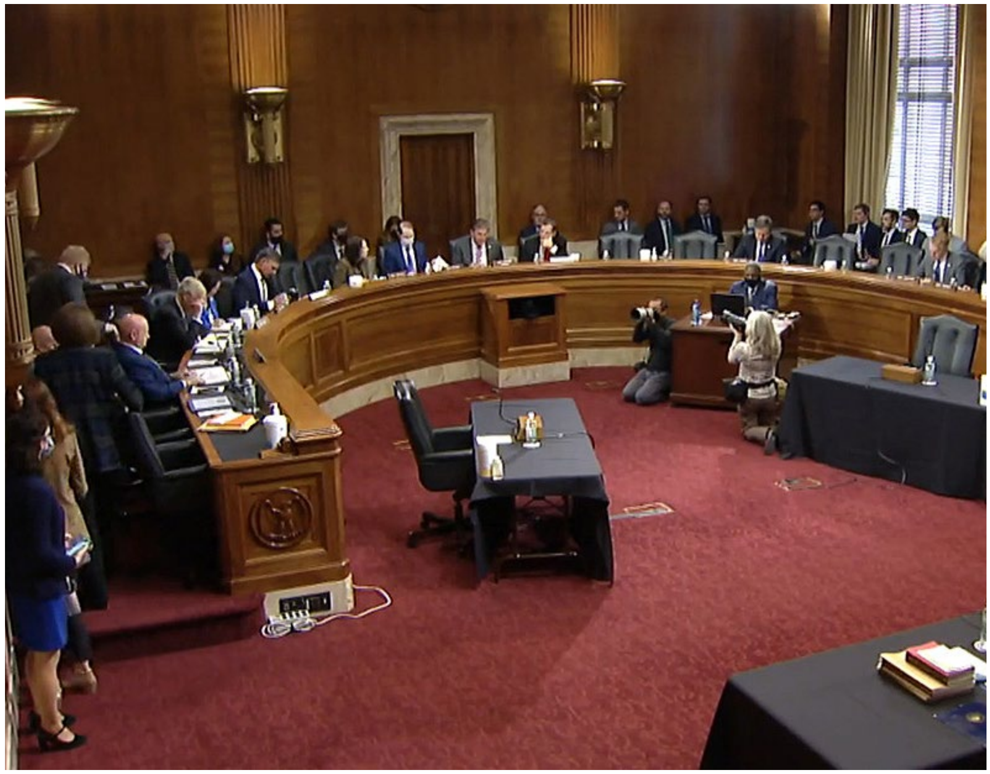
Phillips was advanced as part of a slate of five nominees, including Charles Sams to be director of the National Park Service and Brad Crabtree to be assistant secretary of energy for fossil energy and carbon management. The committee held a confirmation hearing for the three Oct. 19. (See *Phillips, FERC Get Little Attention at Confirmation Hearing*.)

"I believe Mr. Phillips will bring a wealth of expertise in safeguarding reliability and affordability to" FERC, Ranking Member John Barrasso (R-Wyo.) said in praising each of the five nominees last week. "While I don't necessarily agree with all of their views, I do believe they are well qualified and deserving of support."

The committee also advanced separately by a 12-8 roll call vote the nomination of Asmeret Berhe to be director of the Department of Energy's Office of Science, with most Republicans opposed.

If confirmed, Phillips would join Chairman Richard Glick and Commissioner Allison Clements to give Democrats a 3-2 edge on the panel.

Organizations swiftly praised the committee for acting and called on the Senate to confirm Phillips as soon as possible.



The Senate Energy and Natural Resources Committee swiftly advanced Willie Phillips' nomination to be a FERC commissioner to the Senate floor Nov. 2. | *Senate ENR Committee*

"Given the significant transmission and power market reforms necessary to unlock America's growing renewable energy economy, a full complement of five FERC commissioners is critical for accelerating the clean energy transition," American Council on Renewable Energy CEO Gregory Wetstone said in a statement.

"We need strong, swift action from FERC to update existing organized market designs and rules, improve competition in regions without organized markets, and support efficient and cost-effective expansion of the transmission grid to harness the full potential of advanced energy technologies," said Jeff Dennis, managing director and general counsel at Advanced Energy Economy, which represents companies that provide grid-scale and distributed technologies and services. ■

FERC/Federal News

Energy Groups Quick to Praise Infrastructure Bill Passage

Energy Provisions Provide Billions for Efficiency, Transmission, Battery Supply Chains

Continued from page 1

energy-efficiency upgrades, she said.

The final vote Friday was 228-206, with 13 Republicans joining all but six Democrats in support. The latter are progressives who had wanted a simultaneous vote on the budget. The trade-off to get the vote on the infrastructure bill was a subsequent procedural vote setting up the budget vote for mid-November, pending an analysis from the Congressional Budget Office that some moderate Democrats had held out for to ensure the bill is completely paid for.

Speaking on Saturday, Biden framed the infrastructure bill's passage as a big step for the U.S. to deliver on its carbon reduction and commitments made at the U.N.'s 26th Conference of the Parties (COP26) in Glasgow, Scotland, last week, and to assert its leadership in global clean energy markets.

"It will get America off the sidelines on manufacturing — manufacturing of solar panels, wind turbines, battery storage, energy and power for electric vehicles from school buses to automobiles," he said.

Biden also noted he had not signed the bill immediately over the weekend because he wants to have the Democratic and Republican lawmakers who negotiated the package at the ceremony. It should occur "soon," he said.

The top line figures for the bill, as reported by Axios' Sarah Mucha and Andrew Solender, include $73 billion for grid infrastructure, and $7.5 transportation electrification split evenly between EVs and chargers, low-emission buses and ferries.

A major portion of the bill's spending covers more traditional infrastructure, for example, to fix the country's aging roads and bridges ($110 billion), water infrastructure ($55 billion) and rail ($66 billion).

On the more nontraditional side, broadband gets $65 billion, while $47 billion in "resiliency" spending targets flooding, wildfires and coasts.

Getting 'Steel Underwater'

While $73 billion in grid infrastructure spending looks impressive, Rob Gramlich, president of Grid Strategies, cautioned that the bill's allocations for new transmission are considerably less, with most of the money going to upgrades and improvements on existing lines.

The U.S. Capitol | *David Maiolo, CC BY-SA-3.0, via Wikimedia*

For new construction, the Department of Energy gets $2.5 billion to support new, non-federal transmission projects by entering into capacity contracts or providing loans to developers, according to Gramlich's analysis of the bill. DOE's Smart Grid Investment Matching Grant Program gets $3 billion, which can be used for the purchase and installation of grid-enhancing technologies.

Another key provision requires DOE to consider the integration of renewable energy resources and lower costs to consumers when designating transmission corridors of national interest. It also allows FERC to issue permits for construction or modification of certain interstate transmission facilities if a state commission denies or fails to process an application seeking approval for the siting of such transmission facilities.

The 30% transmission investment tax credit in the Build Back Better bill is probably going to be the main catalyst for new projects, Gramlich said. But he said the funding in the infrastructure bill is a strong signal to developers to begin planning for the buildout of transmission, including for offshore wind.

"With some of these loans and grants, we could go to … the states from Mid-Atlantic through New England and say, 'Hey, you have 30 GW of offshore wind [planned], but nowhere near the transmission needed to collect it [and] bring it to shore. How about we use some of these new loans and grants?'" Gramlich said in a phone interview with *RTO Insider*. "We'll pay for some of it through federal dollars if the states and RTOs can agree on land for the rest of it."

While getting to "steel underwater" might take a while, he said, the funding "might be the critical link needed to get everybody together to do what's needed by the end of the decade."

Urgency to Decarbonize

A sampling of other energy provisions in the

FERC/Federal News

2,740-page bill includes:

- $500 million through 2026 to help states develop energy conservation plans that incorporate transmission and distribution planning, as well as broad vehicle electrification to reduce carbon emissions in transportation sector.
- $140 million for a demonstration project for the mining and refining of rare-earth minerals, using feedstock from mine wastes and drainage, and another $3 billion to be used for grants to support advanced battery manufacturing and recycling. This section also calls the departments of the Interior and Agriculture to work on streamlining permitting for the mining of rare-earth minerals on federal land.
- more than $300 million through 2026 for grants to carbon-utilization projects, and another $100 million in the same time frame to support the design and development of carbon transport systems.
- more than $3.2 billion for DOE's advanced nuclear demonstration projects through 2027, and $6 billion, split over five years, to support continued operations at existing nuclear plants threatened with closure.

"As the urgency to decarbonize grows, the next generation of nuclear reactors is essential to reaching our ambitious climate goals," said Maria Korsnick, president and CEO of the Nuclear Energy Institute. "Through continued support for nuclear energy innovation and funding of the Advanced Reactor Demonstration Program, Congress has signaled its commitment to accelerating the deployment of innovative reactor technologies over the next decade while bolstering U.S. technological leadership globally."

Similarly, Madelyn Morrison, external affairs manager for the Carbon Capture Coalition, said the bill's carbon capture provisions mark "a major step forward in fostering economy-wide deployment of carbon management technologies to achieve net-zero emissions by midcentury, while ensuring the long-term viability of key domestic industries and safeguarding high-wage jobs that sustain families and communities."

The bill's support for offshore wind is more indirect, according to Liz Burdock, CEO and president of the Business Network for Offshore Wind, pointing to its investments in the grid, ports and innovation research. But, Burdock said, "achieving the ambitious offshore wind goals set by the Biden administration requires accelerating the development of a local supply chain as explosive growth in global markets draws investors' attention away from the American market."

The next step is passage of Build Back Better, she said, "which includes mission-critical investments in U.S. manufacturing and component development, further port investment and expanded transmission funding. All elements are critical for the full deployment of offshore wind in the U.S."

Despite the House vote on Friday setting up possible passage for mid-November, the budget bill must still navigate continued in-fighting among House Democrats and further trims and revisions by conservative Democrats in the Senate. But the Democrats' electoral losses last week in Virginia and narrow gubernatorial victory in New Jersey have increased the pressure for action. (See related story, *GOP Wins in Va. Raise Questions About State's Climate Policy*.)

Answering a reporter's question Saturday on the elections, Biden said, "The one message that came across was: 'Get something done. It's time to get something done. You all stop talking. Get something done.'" ■

Southeast

Duke Touts Clean Energy Progress, Strong Earnings in Q3

Post-pandemic Bounce-back in Electricity Is Driving Growth

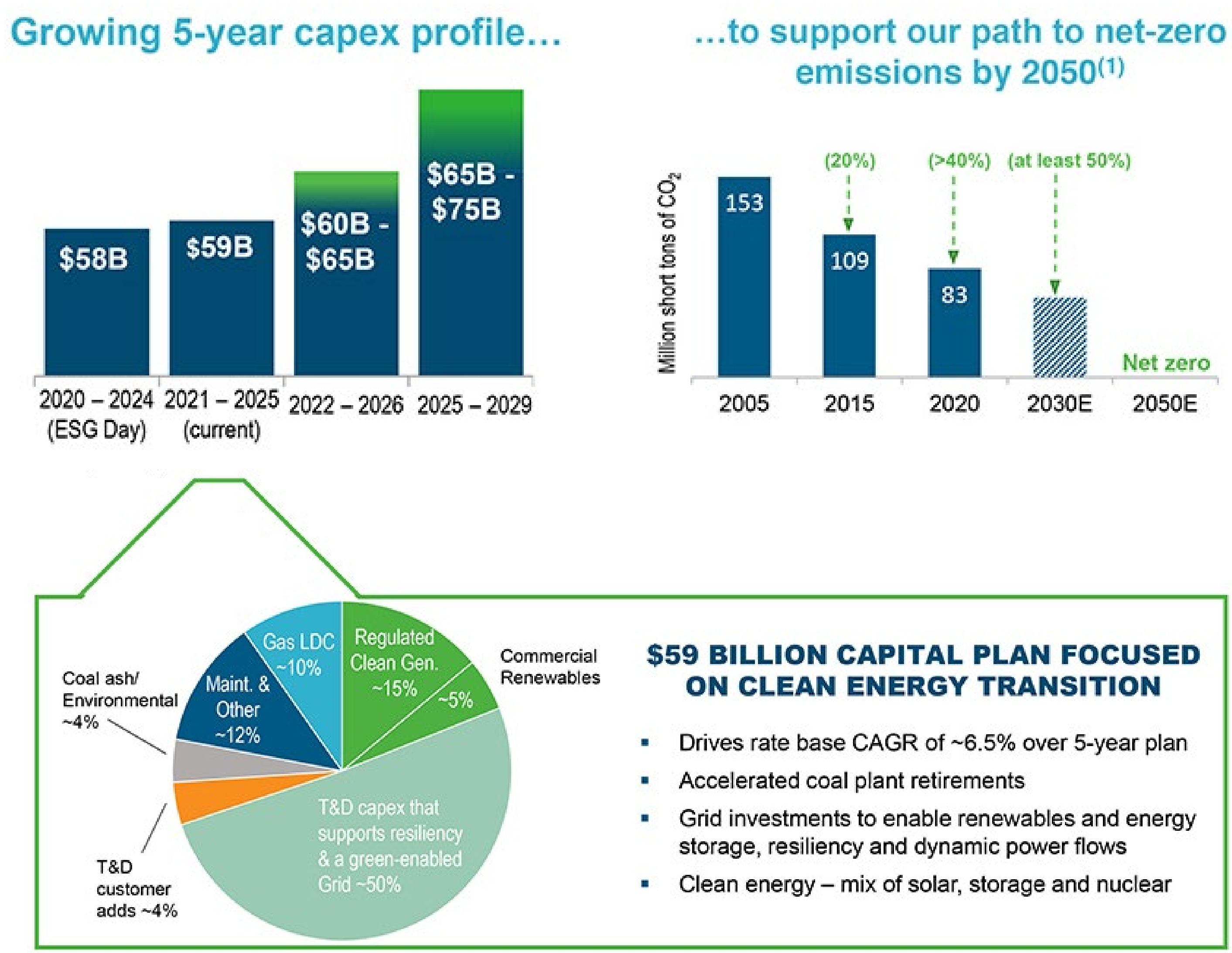
By K Kaufmann

Duke Energy CEO Lynn Good spent most of Thursday's third-quarter earnings call talking about the progress the utility has made on its climate goals and clean energy transformation, such as cutting emissions more than 40%, accelerating the closure of coal plants and launching a new sustainable financing initiative for "green and social projects."

Duke will finance a range of clean energy projects — non-hydro renewables, energy efficiency and storage — via bonds, loans or commercial paper, according to a *report* on the initiative released Nov. 2. Nuclear projects will not be eligible, and the utility has pledged to provide transparency with a website that will track the money it allocates to projects and their environmental impacts.

Spokesperson Meredith Archie said Duke has financed $2.3 billion in projects with green bonds since 2018, but the utility has not committed to any specific spending targets for the new initiative. Rather, the initiative will be part of Duke's capital expenditures, which, Good said, are expected to grow from $59 billion for 2021-2025 to $65 billion to $75 billion by 2029.

"As we look ahead, our pace of change will accelerate as we work toward our carbon reduction goals and the broader clean energy transformation across all of our jurisdictions," Good said.



Capital plan focused on clean energy transition | *Duke Energy*

Southeast

According to information in the slide deck for the call, the utility sees 50% of its capital spending going to transmission and distribution investments in resiliency and a "green-enabled" grid and another 20% to renewable projects.

The passage of *House Bill 951* in North Carolina in October has upped the ante for Duke, which had originally committed to cutting its carbon emissions 50% by 2030, on the way to achieving net zero by 2050. A bipartisan compromise, the new law mandates a cut of 70% over 2005 levels by 2030, while keeping the 2050 goal for net-zero. (See *NC Compromise Energy Bill Passes Senate, Heads Back to House*.)

The law gives the North Carolina Utilities Commission (NCUC) the primary responsibility for developing a carbon reduction plan, to be reviewed every two years, with utility and stakeholder input. But Good clearly sees Duke as having a major role in shaping the plan, which she said will be "approved" by the commission and will draw on "the conversations that have been ongoing over the last several years.

"We anticipate the active involvement of South Carolina in this process as they have been over the decades in developing and retiring assets that serve both states," Good said.

The law also gave Duke a major win with its authorization of performance-based regulation and multiyear rate plans. Under the law, Duke will have to hit certain performance targets, to be set by the NCUC, but will be able to file a three-year rate plan under which, once approved, the utility will be able raise rates up to 4% in each of the subsequent two years without submitting an annual rate case, as it does now.

CFO Steve Young cited the multiyear rate plan as one of several growth drivers for Duke, and he said 2022 would be a "key year" for the rule making needed to implement HB 951 and the carbon reduction plan.

Young reported third-quarter unadjusted earnings of about $1.37 billion ($1.79/share), up from $1.27 billion ($1.74/share) a year earlier. Adjusted earnings per share were $1.88, a penny over the adjusted earnings of $1.87 per share a year ago.

Another growth driver in the quarter was a bounce-back in electricity demand, especially in the commercial and industrial sectors as the economy recovers from the COVID-19 pandemic and people return to offices, Young said. Residential retail sales took a small 0.2% dip, but overall electricity sales were up 3.4% for the quarter, he said.

Shift Away from Coal

Other green initiatives highlighted by Good included a "low-income collaborative to propose new low-income programs to further help our customers." Archie said the initiative would bring in consumer advocates and other stakeholders to look at rate design, energy efficiency programs and other measures to cut bills for low-income customers.

Good also talked about Duke's accelerated coal retirements, as laid out in the utility's revised integrated resource plans for Duke Energy Carolinas and Duke Energy Progress, submitted to the South Carolina Public Service Commission in August. The commission earlier this year rejected Duke's original plan, which kept more than 3,000 MW of coal-fired generation online through 2038; the revised plan would retire all coal by 2035.

In North Carolina, the utility has retirements planned for three units totaling 677 MW at its Allen Steam Station, one already offline and the other two by the end of the year, Archie said. Another 280-MW of coal fired-generation in Indiana has also come offline this year, she said.

Good expects the revised plans for South Carolina to be approved by the end of the year; the utility's IRPs are still pending before the NCUC. She also noted that Duke Indiana will be submitting its IRP by a Nov. 30 filing deadline. While she said the IRP "will continue to advance efforts to shift away from coal," she did not provide further details. Information on the utility's website sets 2048 as the retirement date for Duke's final coal plant in Indiana.

Responding to an analyst question, Good also aligned Duke's clean energy transition with the clean energy provisions in the bipartisan infrastructure plan and the budget reconciliation bill still in negotiation in Congress.

The utility is seeing "conversation" around the clean energy transition across its service territories in the Carolinas, Indiana and Florida, she said. "You see increasing opportunities for renewable investment, for storage investment, energy efficiency, demand response investment … some of our states also have a keen interest in getting a base amount of electric vehicle infrastructure in place."

Although not mentioned during the call, Duke and Honeywell *recently announced* that the utility will be testing a new, long-duration flow battery technology developed by the tech company to provide flexibility and backup power for renewables. ■

CAISO/West News

Siting Council Endorses Central Wash. Solar Farm

By John Stang

A Washington state board has recommended that Gov. Jay Inslee approve the *application* for a proposed 80-MW solar project in the center of the state.

The Washington Energy Facility Site Evaluation Council (EFSEC) unanimously made the recommendation with little discussion on Oct. 20 and sent its guidance to Inslee the following day. Inslee has until Dec. 19 to make this decision.

The project by OneEnergy Renewables (OER) of Seattle would be located near the town of Moxee in Yakima County.

"The council concludes that Goose Prairie Solar will provide the state and the region with important alternative energy supply and will not cause significant unmitigated environmental impacts or substantial negative effect on the broad public interest," EFSEC's report to Inslee said.

"I thought [the proposal] was very thorough and well-prepared," Chair Kathleen Drew said at the group's meeting Oct. 20. Robert Dengel, the council's Washington Department of Ecology representative, agreed that approval was "straightforward."

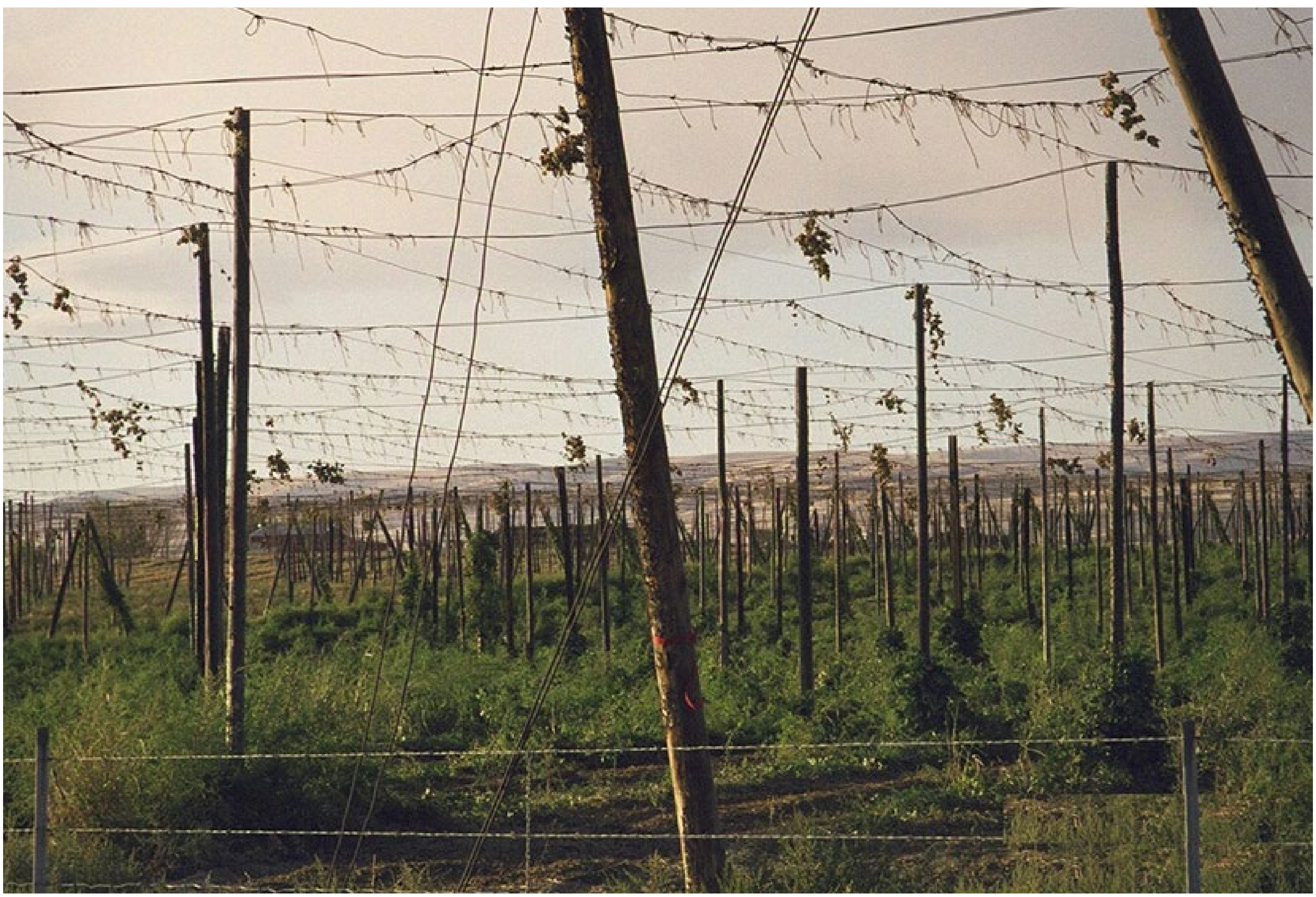
Goose Prairie's application states that the 625-acre solar farm would interconnect with the Bonneville Power Administration's 115-kV Midway-to-Moxee transmission line, which bisects the facility. The document also notes that OER is holding out the option of installing a battery storage system that would not exceed the 80-MW capacity of the project.

The company did not respond to several phone messages from *RTO Insider* to discuss the project, including costs and a construction timetable.

If Inslee approves the application, OER must study the environmental impacts to any habitats for sensitive species and provide a mitigation plan, according to paperwork filed with the EFSEC. The council and the Washington Department of Fish and Wildlife would have to approve that plan.

An EFSEC public hearing on the project held March 16 showed no opposition.

Eastern Washington has four solar farms going through permitting, 28 on the drawing board, two under construction, and one in operation, according to state estimates. EFSEC is currently reviewing nine proposed wind and solar projects for the state. ■



The proposed Goose Prairie Solar project would be constructed east of Moxee, Wash., a hop-growing region. | *Robert Ashworth, CC BY-SA-2.0, via Wikimedia*

CAISO/West News

CPUC Approves More Gas at Aliso Canyon

Winter Reliability Concerns Drive Controversial Decision

Continued from page 1

gas into the atmosphere, leading to a blowout. The leak was contained after four months and multiple failed attempts.

"My family and I still suffer daily from the physical and mental health effects of the Aliso Canyon blowout," Dan Labudas, a resident of the adjacent Porter Ranch community, told the commissioners. "Back in 2015, when the leak occurred, we suffered from nosebleeds, stomach aches, headaches, nausea and other physical and mental ailments. The four months it took to seal the leak were some of the most stressful and devastating months for my family and community."

The ailments Labudas described were common to many residents living near the facility. In late September, SoCalGas and its parent company Sempra Energy agreed to pay $1.8 billion to settle the claims of 35,000 victims of the leak.

Labudas on Thursday urged the CPUC to deny any increase in storage limits and to shut down Southern California Gas' sprawling underground facility, a main gas supply for the Los Angeles Basin.

The CPUC's original proposed decision called for increasing Aliso Canyon's storage limits from 34 Bcf to nearly 69 Bcf. Commissioner Martha Guzman Aceves offered an alternative that would allow an increase to just over 41 Bcf, enough to ensure reliability this winter for ratepayers in Southern California, she said.

The decision is "very limited to the winter interim storage levels," Guzman Aceves said.

The SS-25 well at Aliso Canyon spewed 107,000 tons of natural gas over four months. | *Blade Energy Partners/ CPUC*

Unpredictable weather and a strained gas supply this year made the measure necessary, she said.

"For a good year-and-a-half now, we have seen the very high fluctuations in our changing climate that many of us thought would be unlikely in the past," Guzman Aceves said. "The extreme weather events have become more and more likely. The extreme heat in the state and the continued drought has greatly impacted the availability of hydroelectricity and, unfortunately, has created greater short-term dependency on natural gas generation. And of course, in addition to extreme heat, there's the potential for the other extreme, and that is the cold winter."

Some public commentors mentioned February's Texas deep freeze and widespread power outages, Guzman Aceves noted. California was fortunate to be having a warm winter at the time but "if we were to get one of those events again this winter, and California was experiencing cold winter days at the same time as the rest of the West," it could create reliability concerns and the possibility of curtailments, she said.

The CPUC is in a multiphase process of studying the effects of closing Aliso Canyon and the alternative resources needed to compensate; the latest in a series of *workshops* was held Wednesday. Guzman Aceves, the assigned commissioner in the effort, said the CPUC remains committed to decommissioning Aliso Canyon or limiting its role.

"Our decision today helps ensure energy reliability for the Los Angeles Basin this winter in a safe and reliable manner," she said in a statement following the vote. "We continue to move forward on planning how to reduce or eliminate the use of Aliso Canyon, and to ultimately reduce our reliance entirely on such natural gas infrastructure as we transition to a clean energy economy."

California's two Democratic senators, Dianne Feinstein and Alex Padilla, last week called for the permanent closure of Aliso Canyon "to protect the safety of Californians."

"It is critical that the California Public Utility Commission outline concrete steps to close this facility while ensuring the reliability of our power grid as we continue the transition to cleaner electricity, heating and cooling," Feinstein and Padilla said in a joint statement. ■

CAISO/West News

CPUC Applies New Safety Metrics to PG&E

Can be Used in Enhanced Oversight and Enforcement Process

By Hudson Sangree

The California Public Utilities Commission adopted criteria Thursday allowing it to hold Pacific Gas and Electric more accountable for starting wildfires or undermining reliability with public safety power shutoffs.

PG&E's failure to meet the 32 new safety and operational metrics can serve as triggering events in the CPUC's enhanced oversight and enforcement process. Established as a condition of the utility's bankruptcy reorganization last year, the six-step process involves increasing oversight and penalties, potentially culminating in the revocation of PG&E's operating license.

"Each step is triggered by a specific finding or specific events, and the triggering mechanisms include a failure to make specific, sufficient progress on the metrics that we're adopting today," Commissioner Clifford Rechtschaffen said of the plan. "It's a very important part of making sure that we can implement this unique six-step enforcement framework, which we think is very important to holding PG&E accountable."

PG&E is currently in the first step of the process for failing to prioritize vegetation management around power lines in high-risk fire areas. A tree falling on a PG&E line is suspected of this summer's immense Dixie Fire. (See *CPUC Applies Stricter Oversight to PG&E*.)

In August, CPUC President Marybel Batjer warned PG&E it could face additional oversight.

"I have directed California Public Utilities Commission staff to conduct a fact-finding review regarding a pattern of self-reported missed inspections and other self-reported safety incidents to determine whether a recommendation to advance [PG&E] further within the [CPUC's] enhanced oversight and enforcement process is warranted," Batjer said in a letter to PG&E CEO Patti Poppe. (See *CPUC, Judge Pressure PG&E to Clear High-Risk Lines*.)

The new and updated metrics adopted Thursday include injuries and deaths among members of the public caused by PG&E operations, the frequency and duration of unplanned outages, and the number of fire ignitions in high-risk fire areas.

Another factor is the impact on reliability of PG&E's public safety power shutoffs (PSPS). The intentional blackouts are meant to prevent fires, but PG&E has been criticized recently for using PSPS too often and without warning customers. (See *PG&E Expects $1B in Costs from Dixie Fire*.)

Starting in March, PG&E must file reports every six months with the CPUC that include data for each metric, a description of progress toward its safety targets and proposed methods for remedying deficiencies.

The measures are part of the CPUC's Safety Model Assessment Proceeding (S-MAP), a means of applying risk-based, outcome-driven criteria to large investor-owned utilities through their general rate cases. The CPUC on Thursday added metrics for Southern California Edison, San Diego Gas & Electric and Southern California Gas to consider when investing in infrastructure and operations.

"Transparent, risk-based investment decision-making approaches better inform the CPUC and interested parties in evaluating how energy utilities assess, manage, mitigate and minimize safety risks," the commission said in a statement. ■

A photo filed in federal court shows a tree suspected of starting the nearly 1-million-acre Dixie Fire. | *PG&E*

ERCOT News

Vistra Recovering from Winter Storm's Costs

CenterPoint Profit Surges; OGE Earnings Flat

Vistra CEO Curt Morgan | © *RTO Insider LLC*

Vistra CEO Curt Morgan on Friday celebrated his organization's recovery from the *$1.6 billion in losses* suffered in the wake of February's Winter Storm Uri by saying he was excited to share details of the long-term capital allocation plan.

"It's hard to believe we are still in the same year where we experienced the significant effects from Winter Storm Uri," Morgan said during a conference call with financial analysts. "We are beginning to execute on our strategic priorities … that have begun prior to Uri but accelerated greatly immediately on the heels of the storm."

Vistra plans to strengthen its business model, which includes both generation and retail sales, through investments in its fleet and fuel supply and improved risk management practices. Morgan said that involves $2 billion in share repurchases through next year, just over 60% of its market capitalization, "for as long as our stock remains at what we believe is such a meaningful discount to its fundamental value."

The company's quarterly results excluded a net $10 million "benefit" related to Uri, including in ERCOT resettlements and revenue true-up of $43 million net of $33 million in bill credits applied to large commercial and industrial customers that curtailed during the storm. Vistra also expects to receive about $500 million in proceeds when the grid operator begins securitizing the market's uplift balance in the first quarter of 2021.

Morgan said the company has already completed about 85% of the $500 million "self-help" initiatives it announced after Uri, including monetizing certain commercial positions, generation savings from lower operations and maintenance project work, retail savings, and reduced administrative expenses. "All of that done without really impacting any future periods," he said.

Vistra *reported* third-quarter ongoing operations of adjusted earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.177 billion, down slightly from last year's third quarter of $1.183 billion.

The company uses adjusted EBITDA as a performance measure because it believes that external analysis of its business is improved by visibility to both adjusted EBITDA and net income prepared in accordance with generally accepted accounting principles.

Vistra's share price gained $1.25 Friday and closed the week at $20.46. It dropped to $17.25 in February after the company's Uri losses were disclosed. (See *Vistra Stock Plunges After Market Losses*.)

CenterPoint Profits Surge

Another Texas company hammered by the winter storm, Houston's CenterPoint Energy, said its profits surged during the third quarter.

The utility *delivered* third-quarter earnings of $195 million ($0.32/diluted share), nearly triple 2020's third-quarter performance of $69 million ($0.13/diluted share). That beat analysts' expectations of $0.28/diluted share compiled by Thomson Reuters.

"We now have six quarters of meeting or exceeding expectations, but we believe that there is much more to come," CEO Dave Lesar said.

He said the company has mechanisms in place to recover the storm's gas costs in its various jurisdictions and recently reached a settlement on prudence proceedings supporting securitization of 100% of gas costs in Texas.

CenterPoint has also begun recovery in Minnesota and is "working with stakeholders … to reduce the impact on our customers," Lesar said.

The utility's share price finished the week at $26.67, a 40-cent gain following the earnings announcement.

OGE Energy Maintains Status Quo

OGE Energy **released** quarterly earnings Thursday of $252 million ($1.26/share) as compared to $177 million ($0.89/share) in the third quarter last year. The utility narrowed its year-end guidance to $1.79-$1.83/share.

Oklahoma City-based OGE has reached a joint settlement that would, with regulatory approval, allowing it to securitize $875 million over 13 years and recover 99% of the fuel and purchased power costs incurred during Uri.

The company's share price gained a penny over its per-earnings close, finishing the week at $34.60. ■

— Tom Kleckner

OG&E service crew works on restoring service following Winter Storm Uri. | *OG&E*

ERCOT News

ERCOT Briefs

Texas Comptroller: Winter Storm Uri's Losses at $80B-130B

The Texas comptroller's office said last week the financial fallout from February's Winter Storm Uri could be as high as $130 billion, as *earlier estimated* by the Federal Reserve Bank of Dallas.

Texas Comptroller Glenn Hegar said in October's Fiscal Notes *report* that the storm resulted in between $80 billion and $130 billion in financial losses to the state's economy.

Glen Hegar | *Texas Comptroller*

The Dallas Fed estimated the losses based on "a result of power loss, physical infrastructure damage and forgone economic opportunities."

The storm knocked out power for nearly 70% percent of Texans and disrupted water utilities, leaving many Texans without heat or running water for extended periods. The state has also attributed 210 deaths to the storm.

"The exact impact on Texas energy customers is still difficult to discern," the comptroller's report said. "What we do know is that all major sources of energy in the state experienced failures."

According to the report, the Texas A&M AgriLife Extension Service assessed agricultural losses at more than $608 million and ranchers' economic losses at nearly $228 million. The service also estimated citrus farmers' losses of at least $230 million.

500 MW to Depart Market

ERCOT will lose almost 500 MW of capacity if the cities of Austin and Garland suspend operations at two aging resources.

Austin Energy said last week it will retire its 44-year-old Decker Creek 2 natural gas-powered generator after the winter season. The utility *said* the unit has "aged past its useful life" and has become more expensive to operate. It *submitted* a notice of suspension of operations (NSO), effective March 31, 2022, to ERCOT on Nov. 1.

The Austin City Council in 2017 approved Decker 2's retirement as part of a comprehensive resource plan and reaffirmed that decision in March 2020. The plant's four 50-MW peaking gas turbines will continue to operate.

On Thursday, Garland Power & Light also *filed* an NSO notifying ERCOT that the utility will indefinitely suspend operations at a 78-MW gas turbine at its Ray Olinger power plant. The unit dates to 1967.

Market participants have until Nov. 29 to submit comments before the ISO makes a final decision on the NSOs. ■

— Tom Kleckner

Decker Creek Power Station | *Austin Energy*

ERCOT News

PUC Spins its Wheels on New ERCOT Market Design

By Tom Kleckner

The clock continues to tick on the Texas Public Utility Commission's self-imposed December deadline for the ERCOT market redesign, with the regulators no closer to consensus than they were during their last design work session.

During the PUC's fifth work session on a new market design Thursday, PUC Chair Peter Lake again brought up a *load-serving entity obligation* as a means to provide firm dispatchable generation in a market flush with renewable resources. Again, he faced pushback from the other three commissioners concerned over the mechanism's effect on ERCOT's "crown jewel" of a retail market. (See *Texas PUC Nears Market Redesign's Finish Line*.)

Lori Cobos, who was CEO of the consumer-oriented Office of Public Utility Counsel before being appointed to the PUC, reminded the commission that ERCOT's market was deregulated more than 20 years ago to take investment risk away from consumers served by regulated utilities and place it on investors.

"I feel that we're taking that risk and putting it right back on the consumers and steering away from the reliability principles of [the *1999 legislation*]," she said. "We must be vigilant and ensure we're not weakening the market and putting the risk back on consumers. I continue to believe we need to move in a strategic, targeted manner while we take the time to thoughtfully, deliberatively, holistically evaluate all long-term options that must be fully evaluated and considered before pulling the trigger."

"I'm trigger happy. The grid is demanding we be trigger happy," said Lake, who often refers to legislation passed earlier this year in the wake of February's Winter Storm Uri and the compliance burden it places on the PUC.

The LSE obligation addresses resource adequacy concerns by introducing a formal reliability standard and a mechanism to ensure sufficient resources meet this standard. (See *Study Suggests Texas LSEs Can Provide Reliability*.)

In an October *memo*, Lake suggested parameters for the LSEs' obligation. They would need to have firm resources to meet 50% of their forecast net peak load three years out, 70% two years out, 90% one year out and 100% one month out.

"I'm worried about suppressing the animal spirits of the real-time market," Commissioner Will McAdams said, calling for market flexibility to price-responsive behavior.

"We've been asking for ideas and gotten a very narrow scope of ideas," Lake said. "An LSE obligation is not a risk on consumers; it's a risk on companies that have promised to provide power to those consumers. Those retail companies also have investors. In no way would an LSE obligation move risk to consumers."

To back up his point, Lake recounted a recent meeting he had with a retailer, who said "we don't provide power; we sell things," Lake said. "Which is not, in my mind, providing reliable power to our consumers or businesses."

"I have no problem adding some risk [on LSEs]," he said.

Capacity Market in Disguise

Attorney Catherine Webking, general counsel for the electric retailer lobbying group Texas Energy Association for Marketers, said her constituents have "very grave concerns" about the LSE obligation's capacity requirements.

"That's not to say that [retail electric providers] don't hedge and buy firm power … they do, today," she said. "It still looks to the LSE to demonstrate a capacity procurement, specific to a physical resource, which is not how it's done today."

Webking said that qualified scheduling entities (QSEs) procure resources on behalf of the retail electric providers (REPs) in ERCOT's market.

"Ultimately, a physical obligation is there, but the individual REP does not necessarily have to demonstrate which unit and which megawatts at that resource are being procured," she said. "As I understand the proposal, the LSE would have to say I understand these physical resources are where I'm buying power. It's still tied to physical generation and physical capacity of that unit. There's no revenue stream with that forward capacity purchase."

Independent consultant Alison Silverstein, who advocates for demand response and energy efficiency measures, said the LSE obligation "looks pretty much like a capacity market" in disguise.

"It also requires both the commission and ERCOT do a significantly better job of planning and forecasting than either of them have shown the capability of doing to date," she said.


PUC Chair Peter Lake | *Texas PUC*

Stoic Energy's Doug Lewin, who has been *live tweeting* the PUC's recent work sessions, lamented other solutions that have been sidelined in favor of the LSE obligation's discussion.

"They've spent so much time talking about the [LSE obligation], which won't make a difference for a couple of years anyway," he told *RTO Insider*. "They could have implemented some of the other things that could have been implemented much faster, like demand response and targeted energy efficiency."

In drawing the discussion to a close, Lake said, "It's clear we still have a lot of work to do."

He asked the commissioners to "put pen to paper" before the next work session and provide their thoughts on firming mechanisms, a reliability adder, and other market changes.

The PUC delayed decisions on revisions to the operating reserve demand curve and other changes until The Brattle Group completes an assessment of alternative ORDCs. An *overview of the study* dropped Friday.

Brattle suggested a $10/MWh adder to cover start-up costs of marginal resources could be imposed around 5,550 to 5,800 of online reserves to encourage self-commits and reduce the need for reliability unit commitments.

The commission tabled a *rulemaking* that will lower the high system-wide offer cap (HCAP) from its current $9,000/MWh to $4,500/MWh to time its publication with changes to the ORDC. The HCAP was dropped to $2,000/MWh after February's winter storm and is set by rule to revert back to $9,000/MWh on Jan. 1 (*52631*). ■

ISO-NE News

Eversource Warns of Higher Winter Bills as Gas Prices Bounce Back

By Jason York

Eversource Energy on Wednesday warned that customers will likely see a spike in their electricity and gas bills this winter compared to last year's, as natural gas prices surge nationwide.

During a call with investors to *discuss* its third-quarter earnings, Eversource CFO Philip Lembo said that starting in January ratepayers in Connecticut and Massachusetts will likely see a 2- to 3-cent/kWh rate increase on their bills, which translates to an additional $20 to $25/month on a typical bill. Gas customers can expect an increase of about $30. New Hampshire rates remain in effect until February.

Energy prices hit 10-year lows in 2020 amid the COVID-19 pandemic. Because of wintertime natural gas constraints in New England, ratepayers usually see up to a 2-cent/kWh increase in January that often reverses by the summer, but gas prices have risen significantly since the beginning of the year, driven by an increase in global demand during the ongoing economic recovery and a significant drop in U.S. gas supply. Between Oct. 20 and 27, natural gas spot prices rose from $4.79/MMBtu to $5.86/MMBtu, according to the most recent weekly *report* from the U.S. Energy Information Administration. At the Algonquin Citygate, which serves Boston-area consumers, the price went up from $4.52/MMBtu to $5.65/MMBtu.

Isaias Settlement

The earnings results came on the heels of last month's announcement of an approved settlement over penalties and return on equity reductions levied on the utility for its handling of Tropical Storm Isaias in August 2020. The settlement will provide $65 million in bill credits and $10 million for low-income assistance programs.

"Settling critical regulatory and legal disputes was a necessity to reset our relationship with key Connecticut stakeholders," Eversource CEO Joe Nolan said. "We all want the state to move ahead on addressing critical energy and climate issues, and the outstanding disputes have the potential to delay some of this important work."

Before the settlement, Eversource would have been set to lose more than $150 million based on the penalties and ROE cuts thanks to the *Take Back Our Grid Act*, which directed the Public Utilities Regulatory Authority to develop and implement performance-based regulations including financial penalties and ROE reductions.

In a rare *dissent*, PURA Chair Marissa Gillett said that "more devastating storms" like Isaias "will come to pass," and tools such as an ROE reduction "would more acutely encourage Eversource's executives to properly prepare for and respond to such storms." Gillett also said she was "apprehensive of a future where we still do not have a court-backed interpretation of PURA's regulatory authority in holding utilities accountable following a storm event."

State Rep. David Arconti (D), co-chair of the General Assembly's Energy and Technology Committee, told *RTO Insider* that Eversource "may want to move forward, but I'm not necessarily there yet."

Arconti said the Lamont administration, like previous administrations, had a predisposition to settle, but "there are some cases where I think it's worth it to go to the mat."

"I do think the settlement is just more par for the course and kind of perpetuates some of the norms on how we've gotten to where with certain things," Arconti said.

When the average person looks at the settlement, they will not understand why specific rates are frozen and other areas are increasing on their bills, he said. "It doesn't help us do our job when the people see stuff like that."

Earnings

Eversource reported earnings of $283.2 million ($0.82/share), down from $346.3 million ($1.01/share) for the same period in 2020. The company's transmission segment earned $139.4 million in the quarter, nearly $14 million more than last year's. Eversource attributed the increase to higher level of investment in its infrastructure. ■

Call transcript courtesy of Seeking Alpha.

Eversource Energy's Berlin, Conn., campus | © *RTO Insider LLC*

ISO-NE News

Northeast RTOs Asked to Run Offshore Tx Studies

Continued from page 1

of Concerned Scientists and New York Offshore Wind Alliance.

"No one has really kicked the tires on this, so we felt like [IPSAC] was the place that could do it," Howe said.

Shell Offshore Wind also made a *presentation* from a developer's perspective, saying that that the lack of planning is really hindering it, Howe said.

"Timing is a key consideration given that states will proceed with clean energy initiatives before FERC resolves issues in its" Advance Notice of Proposed Rulemaking, Shell said. (See *Transmission Industry Hoping for Landmark Order(s) out of FERC ANOPR*.)

The Joint ISO/RTO Planning Committee and IPSAC, through the Northeastern ISO/RTO Planning Coordination Protocol, are positioned to provide policymakers with analyses and information in the near term on benefits that may be obtained with enhanced interregional coordination, Shell said.

Federal Backing

Because of the way that interregional projects work generally, it's hard to get regions to agree on any solution, Howe said.

"Effectively all regions — in this case three regions — would have to agree not just that an interregional solution is the way to go, but exactly what that interregional solution would be, and that often doesn't happen," Howe said. "So one of the reasons you don't see a lot of interregional projects is because ... [the parties] often can't come to an agreement on what a particular solution might look like."

The group has a powerful ally in Amanda Lefton, director of the Bureau of Ocean Energy Management. Speaking at a conference in New York last month, Lefton said a planned approach to offshore transmission is going to be critical, and "something that's been incredibly clear is that we need a strong collaborative effort between states and the federal government." (See "Powering NYC with Renewables," *New York Writing Ending to Tale of Two Grids*.)

The U.S. Department of Energy last month released a *report* on the gaps that will need to be filled to build enough transmission to interconnect electricity from turbines in the Atlantic to power grids along the East Coast. (See *DOE: Atlantic Coast Needs Integrated Transmission Planning for OSW*.) The DOE report cited a lack of comprehensive evaluation across all the necessary aspects of transmission planning to support offshore wind energy development at scale.

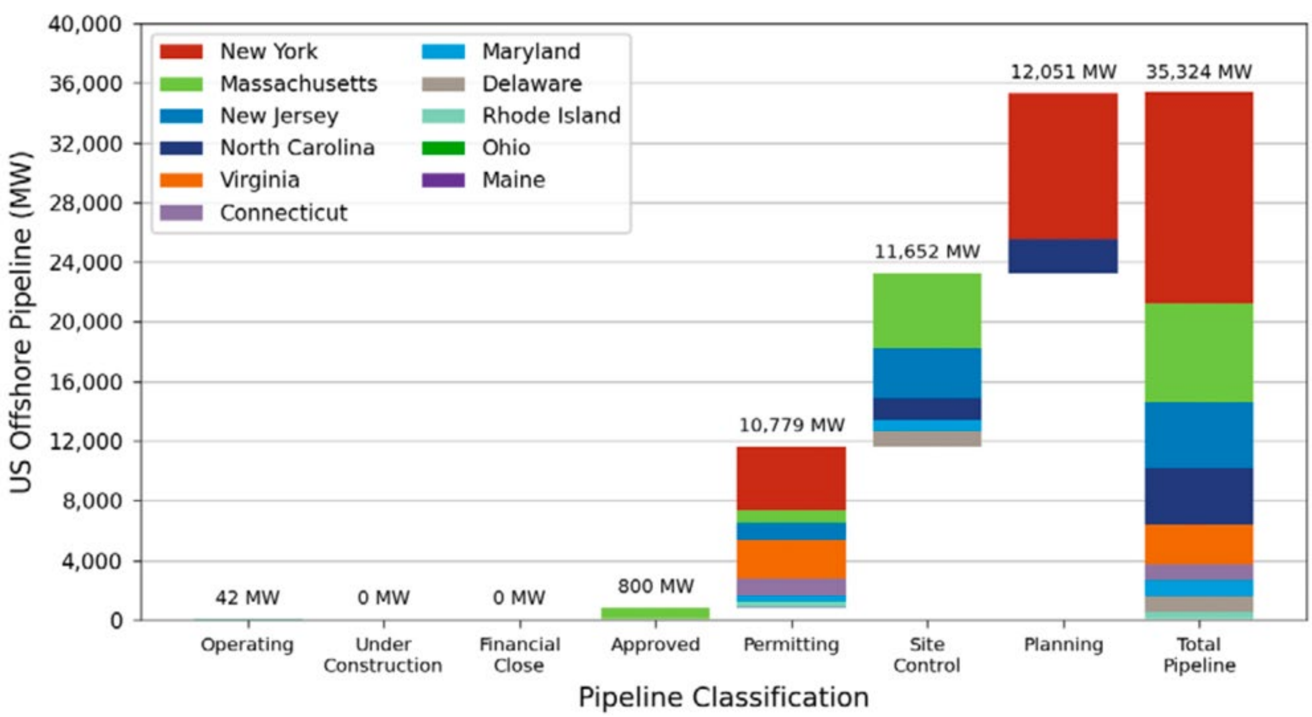
"Current reactive processes that evaluate individual offshore wind projects may not optimize benefits to support deployment of 30 GW by 2030 and beyond. As a result, comprehensive interregional studies of possible offshore wind transmission options are needed," the report said.

If RTOs/ISOs are worried about who will pay for the analysis, there is a provision in the Build Back Better bill, passed by the U.S. House of Representatives on Friday, to allocate $100 million for offshore wind planning.

"To do this study right now seems to be a no-brainer because it does seem like you could identify a lot of efficiencies by looking at how [this could] be built out in a way that takes into account limited interconnection points on land, what's the best way that we can do this, and thinking beyond just one state at a time or even one region at a time," Howe said.

At some point in the next 20 to 30 years, the U.S. will have a lot of offshore wind projects out in the ocean and operating, he said, so it seems like planners would want to say right now what is the most efficient way to build the needed transmission grid.

The next IPSAC meeting is scheduled for Dec. 4. ■



DOE 2021 graph provides the breakdown of development phase by state to meet demand for offshore wind, with projects at various stages. | *DOE*

ISO-NE News

ISO-NE Seeks to Terminate CSO for Conn. Power Plant

By Jason York

ISO-NE put the future of a 650-MW natural gas power plant in eastern Connecticut into potential regulatory doubt when it asked FERC on Thursday to terminate the project's capacity supply obligation (CSO) in the next 60 days.

In a heavily redacted *filing to the commission*, ISO-NE said it is exercising its right to seek termination of the CSO for the Killingly Energy Center after consulting with NTE Energy, the Florida-based developer of the project. If FERC accepts the termination, NTE must forfeit any financial assurance associated with the terminated megawatts. Terminated resources also lose their associated CSO and rights to any related payments. It would also make Killingly ineligible for the 16th Forward Capacity Auction in early February 2022.

ISO-NE spokesperson Matt Kakley told *RTO Insider* that Killingly, which initially secured a CSO in 2019's FCA 13 for the 2022/23 capacity commitment period, was required to meet several development milestones such as financing, permitting, major equipment orders and commercial operation. Developers facing delays in meeting milestones can find other resources to cover their obligations for up to two years. But if a project is still unable to meet its milestone deadlines after two years, ISO-NE has the right to seek termination of the resource's CSO through FERC.

"The ISO is exercising this right with regard to the Killingly Energy Center," Kakley said.

NTE Managing Partner for Development Tim Eves said in a statement to *RTO Insider* that "while we appreciate all of the work that ISO-NE does, we are disappointed that it has not chosen to come down on our side of this equation."

"ISO-NE's determination is based on an incorrect assumption regarding a financing milestone date. Financing for the Killingly Energy Center is imminent, and this filing will only further delay this much needed source of cleaner, more affordable energy," Eves said. "Killingly is the much needed bridge to the clean energy future, and we will exercise all options available to show FERC that Killingly has not only already commenced its construction schedule but also will be online in time to meet its capacity supply obligation."

A spokesperson for the Connecticut Department of Energy and Environmental Protection said the agency has long heard "that there have been questions regarding the viability of this project."

ISO-NE headquarters in Holyoke, Mass. | *ISO-NE*

"Clearly, ISO-NE identified things that called into question the project's ability to reach required project milestones and made their determination to file a resource termination," the DEEP spokesperson said.

Killingly Opponents React

A divided Connecticut Supreme Court in September *upheld* a lower court decision to dismiss a complaint from local environmental group Not Another Power Plant that the Connecticut Siting Council acted "improperly" in its decision when it did not account for potential environmental damage from a needed expansion of a pipeline to deliver fuel. The decision was a legal victory for NTE and Eversource Energy, the latter of which was expected to rebuild an existing pipeline to deliver gas to the facility. (See *Conn. Supreme Court Affirms Lower Court Decision on Power Plant Approval*.)

Opponents of the plant welcomed Thursday's action by ISO-NE.

"People from all over Connecticut have recognized that dirty power generation conflicts with the future we all want and need to avoid the worst impacts of climate change," Samantha Dynowski, director of Sierra Club's Connecticut chapter, said in a *press release* that also captured similar sentiments from other groups opposed to Killingly. "Sierra Club is very hopeful that FERC will accept ISO-NE's request for termination of the capacity contract for the fracked gas power plant proposed for Killingly and that Connecticut can focus on a clean and climate-friendly future. This is a major step in the right direction for clean air and a livable planet."

Kate Donnelly, a member of Killingly, Conn.-based No More Dirty Power, said the plant would increase the pollution in a town "with high asthma rates that already houses a fracked gas power plant."

"Its construction would make it impossible to meet Connecticut's goals to address the climate crisis, [and] the energy from this plant wouldn't even be used in our state," Donnelly said. "For these reasons, people have been fighting construction of the power plant since it was first approved. Even though we were repeatedly told it was a 'done deal,' we fought on. With this news, we are hopeful that it is the beginning of the end of the Killingly Energy Center, and we can all focus on meeting our climate goals through energy-efficiency programs and the development of renewable resources."

Leah Ralls, president of NAACP's Windham-Willimantic branch, said its membership unanimously passed a resolution opposing the construction of the power plant in April.

"Environmental racism and economic injustice can be defeated when we stand together and work toward development and construction of clean, renewable energy sources," Ralls said. "Today's news of ISO-NE's termination filing for [Killingly] brings us closer to that outcome." ■

ISO-NE News

Overheard at NECBC Energy Conference: NECEC Line 'Will be Built'

BOSTON — Ideas to build out the energy infrastructure in New England are plentiful. Still, concerns remain about the execution of potential projects to address the region's ambitious climate change goals in addition to reliability.

American and Canadian business and government officials addressed the ideas-to-execution paradox during the New England-Canada Business Council's 29th Annual Executive Energy Conference on Nov. 4-5.

The recent referendum rejection by Maine voters of the New England Clean Energy Connect transmission line was top on attendees' minds.

The following is some of what we heard during the two-day event.

From left: Paul Hibbard, Analysis Group; Dennis Arriola, Avangrid, Badar Khan, National Grid; Arun Banskota, Algonquin Power and Utilities; and Dave Rhéaume, Hydro-Quebec. | *© RTO Insider LLC*

NECEC Project Vote

Voters in Maine went to the polls on Nov. 2, and a majority of them cast ballots to block construction of NECEC'S 145-mile transmission line through western Maine to deliver 1,200 MW of hydropower from Quebec to Massachusetts. However, on Nov. 3, Avangrid, the parent company of project developer Central Maine Power, filed a *lawsuit* in Maine Superior Court challenging the constitutionality of the referendum. (See *Maine, NY Voters Prioritize Conservation on Election Day*.)

Speaking on a panel Friday, Avangrid CEO Dennis Arriola did not pull any punches about the future of the $1 billion project, which he said will be built on existing rights-of-way and commercial logging lands. NECEC, Arriola said, is good for the economy and environment and is "respectful of the local lands where the transmission lines are going to go."

"The arguments that this project is doing really bad things to the forest, and everything, is totally false," Arriola said. "I think that the narrative has been manipulated by, candidly, some characters that will be on the losing end of the energy transition."

Avangrid CEO Dennis Arriola | *© RTO Insider LLC*

Arriola did not mention any specific "characters" by name.

More baseload fuels are needed to complement the intermittent electricity from offshore wind and solar, according to Arriola. It is essential to understand, he added, that "especially here in the Northeast," projects specific to transmission have been blocked by companies that only care about "the bottom line."

"When you look at what we need in this country, we don't just need the renewables, we don't just need more battery storage, we don't just need more green hydrogen, we need a lot of transmission to be able to transport that clean energy to where it's needed," Arriola said.

If the U.S. and New England are serious about hitting "bold, audacious goals for carbon reduction" and getting to net-zero emissions in the next 15-30 years, he said, it will not happen without transmission.

Kathleen Kelly, Daymark Energy Advisors (left); and Dan Dolan, New England Power Generators Association | *© RTO Insider LLC*

"We've got to stop just talking about things," Arriola said. "We got to put things into action."

Government policymakers must "stand up and help push these projects along when they're done right by the rules" established by them, he said.

Hydro-Québec can be "part of the solution in the Northeast," Dave Rhéaume, senior director of development, strategy and commercial relations outside Québec, said during the panel discussion. He recognizes that whenever Hydro-Québec develops new deals, "obviously they come with very expensive transmission projects" like NECEC. As a renewable energy supplier, Hydro-Québec finds a market that requires renewables and sees the value proposition in building transmission lines that take energy in one direction … for now, Rhéaume said.

"We believe that in the long run, these lines won't be unidirectional anymore," he said. "They will be used to reduce the amount of curtailment periods in neighboring markets."

From left on stage: Gordon van Welie, ISO-NE; John Gulliver, Pierce Atwood Bill Quinlan, Eversource. On video: Richard Dewey, NYISO; Francis Bradley, Canada Electricity Association; Doreen Harris, NYSERDA. | *© RTO Insider LLC*

Speaking of Tx

The referendum in Maine should be "sobering," according to NERC CEO Jim Robb. He believes it put a "stick in the spokes of progress."

There is a "robust transmission system" in New England, according to ISO-NE CEO Gordon van Welie. Still, there is more work to be done ahead of the integration of more renewable energy.

Eversource Energy operates about 50% of the transmission assets in the region, and Bill Quinlan, president of transmission and OSW projects for the utility, said that despite some of the headwinds for extensive energy infrastructure, "there are some paths forward."

Quinlan cited Eversource's $49 million project with National Grid in Boston, the first competitive transmission solicitation under FERC Order 1000. ISO-NE issued the RFP to address transmission violations expected after the retirement of Exelon Mystic Units 8 and 9, whose closing was extended to May 2024, under a two-year, $400 million cost-of-service contract. The Eversource-National Grid project has a projected in-service date of Oct. 1, 2023, eight months before the end of the contract. (See *ISO-NE Chooses Incumbent as Boston RFP Winner*.)

Quinlan said the retirement of a significant fossil-fuel asset like Mystic would help with decarbonization efforts.

"I know there are challenges, but I think if you're creative and you deal effectively with stakeholders, you can build infrastructure, and that is going to be the challenge of the future," Quinlan said. ■

— Jason York

MISO News

Despite Ida, Entergy Reports Strong Quarter

By Tom Kleckner

Entergy said Wednesday that it delivered "another strong quarter" over the summer, despite the electricity grid damage wrought by Hurricane Ida when it made landfall along Louisiana's Gulf Coast in August.

The company *reported* third-quarter earnings of $531 million ($2.63/share), compared with $521 million ($2.59/share) a year earlier. That beat an Investing.com's poll of analysts who had expected earnings of $2.40/share.

Ida was the second most destructive storm to hit Louisiana, after only Katrina in 2005, and inflicted an estimated $2.1 billion to $2.5 billion in damages to Entergy facilities. The company said that resulted in a $75 million to $80 million loss in non-fuel revenue.

CEO Leo Denault said during a conference call with financial analysts that Entergy had invested about $10 billion over the last five years to strengthen its system. He said the newer infrastructure performed well "under the most challenging situations."

"The wind damage was almost exclusively to aging structures built prior to the new standards," Denault said. "The increasing severity of storms is compelling us to take a fresh look at how we can make our system more resilient."

Entergy's restoration force of employees, contractors and mutual assistance crews from 41 states numbered about 27,000, its largest ever, Denault said. Customer outages reached 1 million at their peak, he said, but were less than half that in little more than a week.

"We're committed to minimizing the effect of Ida on customer bills," he said.

The New Orleans-based company plans to securitize its Ida costs, even as costs from 2008 hurricanes Ike and Gustav are about to roll off.

Entergy narrowed its 2021 adjusted EPS guidance range to $5.90 to $6.10 and said it is on track for EPS growth of 5 to 7% through 2024.

The company's shares were trading at $103.36 following the market's close, a 44-cent drop from the previous close. ■

Hurricane Ida damage in New Orleans on Aug. 30 | *Entergy*

MISO News

Last-minute Unease over MISO's Seasonal Accreditation

By Amanda Durish Cook

MISO stakeholders remain apprehensive about the RTO's plan to hold four seasonal capacity auctions with separate reserve margins before the 2023/24 planning year, less than a month before it gets FERC scrutiny.

Nearly all their concerns can be traced to a seasonal capacity accreditation based on a generating unit's past performance during tight conditions.

During a Resource Adequacy Subcommittee call Wednesday, Entergy's Wyatt Ellertson said the accreditation design seems poised to raise several of MISO's local resource zones to the cost of new entry (CONE), which currently stands around $257/MW-day. He asked the grid operator to give members more time to prepare for the changes.

"What I haven't heard you say is this proposal doesn't reflect reality," MISO Director of Resource Adequacy Coordination Zakaria Joundi responded. He said staff is not trying to avoid or achieve CONE pricing in its capacity auction.

In September, MISO leaders gave stakeholders an extra 60 days to digest the proposal. Several stakeholders have said they're incredulous that a seasonal paradigm will improve system reliability. (See *MISO Extends Seasonal Auction Discussions*.)

Staff has said a FERC filing will be made no later than Dec. 1.

Kevin Vannoy, MISO's director of market design, said awarding a greater accredited capacity value to generators that consistently show up when they're needed the most should boost reliability.

"Over time, that will incentivize resources to be available during the time of tightest needs, so that in turn incentivizes reliability," he said.

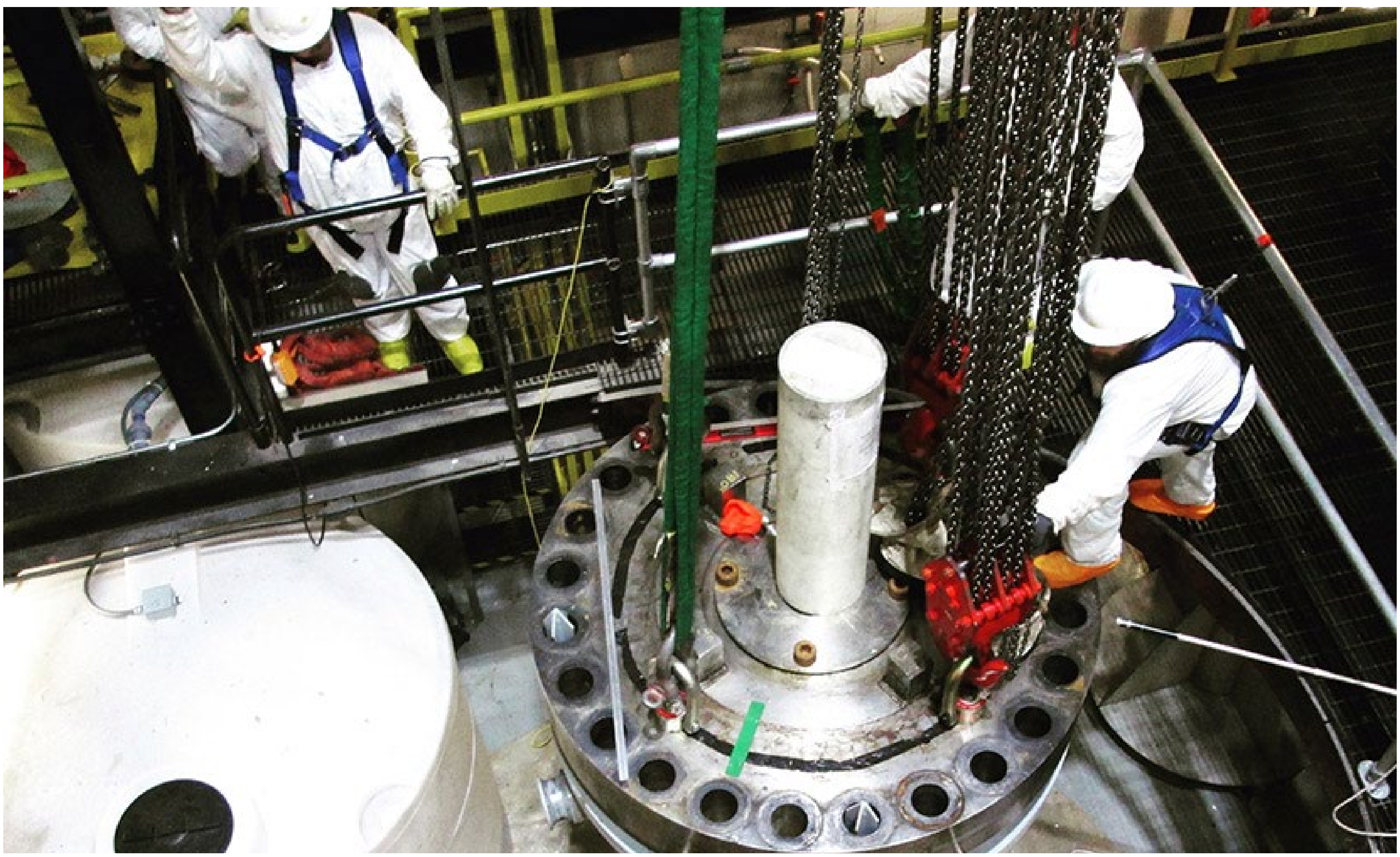
Independent Market Monitor Michael Chiasson said it's only appropriate for a local resource zone stocked with slow, inflexible resources to receive lower accreditations and force the zone to procure additional resources.

Stakeholders asked whether MISO has a plan to alter its accreditation if its resource adequacy outlook improves and it is again flush with reserves. Some said staff was pessimistic to assume that the RTO would always have tight operating conditions as a basis for capacity accreditation.

"We may have to add provisions if we never have less than a 25% reserve margin," Vannoy said. However, he said even three years without a single maximum generation event isn't a guarantee that MISO won't experience tight operating conditions during an upcoming year.

"That's a high-class problem to have," MISO's Scott Wright said.

Coalition of Midwest Power Producers representative Travis Stewart said the RTO's sustained increase in maximum generation events and emergency actions in "mild system



Work at an Xcel Energy nuclear power station | *Xcel Energy*

MISO News

conditions" means that utilities might need to update integrated resource plans and prioritize some generation projects.

"There's indication of a big issue even if the Planning Resource Auction is printing low prices," Stewart said.

He pointed out that MISO's Monitor has long maintained that the capacity auction doesn't reflect the true marginal value of capacity.

Staff has warned that threat of a maximum generation emergency exists on any given day due to increased use of intermittent resources and an aging baseload fleet that's more prone to outages. In spite of system load around 70 GW and mild weather, MISO *entered* conservative operations and a maximum generation alert Oct. 4 in its Midwest region because of planned and unplanned generation outages.

Bill Booth, consultant to the Mississippi Public Service Commission, asked whether MISO is furnishing specific accreditation numbers for individual generators.

Joundi said staff has reached out to members about certain generators' value. He cautioned that MISO doesn't have the resources to produce outputs for a large load-serving entity's entire fleet.

The grid operator will also impose a 31-day limit on planned generation outages in any season before capacity resources must procure replacement capacity. The IMM will also consider requests from generators to be excluded from auction participation, even if it will be uneconomic for units to offer into the auctions.

Ellertson asked MISO to provide the numbers of generators not participating in the auctions due to the 31-day outage threshold.

Minimum Capacity Requirement Exits Filing

MISO will file separately with FERC a minimum capacity requirement request in which members must demonstrate that at least 50% of capacity needed to meet their peak load is secured ahead of the voluntary capacity auction.

MISO had originally intended to include the rule in its seasonal capacity filing.

"We've been receiving a lot of feedback from stakeholders indicating that we need to separate [a capacity demonstration] from seasonal accreditation," MISO counsel Michael Kessler told stakeholders during an October Resource Adequacy Subcommittee meeting. "We've had a lot of internal discussions regarding our best chances for success at FERC."

The Organization of MISO States said it supported removing a minimum capacity obligation from MISO's first filing.

Members Ask for 3 Filings

Some MISO members don't think the filing split goes far enough. DTE Energy *asked* staff to further divide the plan into three separate filings for the seasonal auctions, minimum capacity requirement, and the availability-based accreditation. DTE also asked that the RTO hold off on the accreditation component until it more fully addresses stakeholder concerns.

The utility maintains that the auction and accreditation design hasn't been fleshed out with stakeholders and continues to evolve late in the process.

Members Consumers Energy, Entergy, Madison Gas and Electric, Michigan Public Power Agency, Southern Minnesota Public Power Agency and WPPI Energy joined DTE in the ask.

"Now that it's been split once, it's doable to split it again," DTE's Eric Bidlingmaier said. "Doing so will allow stakeholders to better support or oppose any component of the filing and allow each aspect of the proposal to be evaluated on its own merits."

Bidlingmaier said MISO is attempting to "fundamentally re-engineer nearly every aspect of its resource adequacy construct in a way that no other U.S. RTO has ever undertaken."

Some stakeholders said a three-way split of the filing would provide greater assurance that MISO could implement parts of the plan, instead of having a comprehensive design rejected by FERC.

Customized Energy Solutions' Ted Kuhn said he didn't view the members' ask as "obstructionist," but rather as a plea for staff to propose a better accreditation design.

Wright said he didn't see the request as obstructionist either, but he said MISO views the seasonal auction and accreditation as going hand-in-hand. He noted that the RTO has already granted a delay request by stakeholders and will move ahead with the filing at the end of the month.

During OMS' annual meeting Oct. 28, North Dakota Commissioner Julie Fedorchak said she was at odds with her state's utilities for her support of "starting to hold resources accountable" for their availability.

"I personally am comfortable with this," Indiana Utility Regulatory Commissioner Sarah Freeman said, adding it was imperative that MISO values a resource's contribution accordingly. ■

MISO News

MISO Stakeholders Skeptical of Revamped Meeting Schedule

By Amanda Durish Cook

MISO stakeholders on the Resource Adequacy Subcommittee are chafing at the RTO's new slimmed-down meeting schedule that calls for eight "super weeks" of in-person meetings.

Stakeholders on Wednesday pushed back on MISO's plan to group all stakeholder meetings of its main parent entities into eight separate weeks during the year. That would mean five all-day meetings will be packed into a single week. (See *MISO Wants Abridged Stakeholder Meeting Schedule*.)

The grid operator has promised that while it is reducing the number of meetings, the amount of information it conveys will remain the same. The RASC, Market Subcommittee, Reliability Subcommittee, Planning Advisory Committee, and Regional Expansion Criteria and Benefits Working Group are all affected.

RASC Chair Chris Plante said stakeholders have "relevant" concerns about how information that used to be delivered monthly will be communicated just eight times per year.

"I'm very interested in hearing from stakeholders how these gaps might occur," Plante said.

Travis Stewart, representing the Coalition of Midwest Power Producers, said he and his customers found monthly RASC meetings helpful during the leadup to the April Planning Resource Auction. He asked staff to devise a way to update stakeholders on capacity auction deadlines and developments.

WPPI Energy's Joe Greene asked that meeting dates, which have not yet been set, be finalized as quickly as possible.

MISO's Carmel headquarters | © *RTO Insider LLC*

"I personally don't see this proposal as coming from the stakeholders," Customized Energy Solutions' Ted Kuhn said. He said he had not heard stakeholders asking for fewer or shorter meetings and said the new seasonal auction design is evidence that monthly meetups may still be required.

Plante said the RASC "has the prerogative to establish its own meeting schedule" per the Stakeholder Governance Guide and could add more meetings to the calendar. He said the subcommittee could "pencil in" monthly meetings, noting it's easier to scratch plans than try to organize a last-minute meeting.

"We can always cancel the meeting if there's nothing to talk about," he told stakeholders. "In some respects, this is being driven by the Advisory Committee, so I would encourage all of you to approach your sector representatives."

Consumers Energy's Mary Long said the new schedule's uncertainty is disrupting business travel plans and snarling stakeholders' vacation plans.

"I think this is perhaps convenient for MISO employees, but it's not convenient for stakeholders," she said. "What I've heard is stakeholder committees have the power to determine the cadence and content of the meetings, rather than MISO forcing a cadence."

Cleco Cajun's Tia Elliott said MISO should have held a stakeholder discussion to gather feedback rather than announcing the schedule change through an email to committee chairs.

Bob Kuzman, the RTO's customer affairs director, said the move doesn't have to be permanent, but it does represent the grid operator's return to in-person meetings as the COVID-19 pandemic eases up.

He said the new schedule will give MISO staff and stakeholders a breather between monthly meetings to prepare discussions.

"We get in the cycle of present, get ready for meetings, present, get ready for meetings," Kuzman said. "What I ask for is patience at this time to look, evaluate … and see if this works. If it doesn't, we're happy to reassess."

Customized Energy Solutions' David Sapper said the new meeting schedule might again put the onus on stakeholders to prepare discussions and presentations. He said stakeholders have lately been relying on staff to come up with all discussion points. ■

MISO News

Conservation Groups Win Injunction vs. Cardinal-Hickory Creek

By Amanda Durish Cook

A federal judge on Nov. 1 put on hold the hotly contested Cardinal-Hickory Creek transmission project slated to cut through southwestern Wisconsin after he determined that environmental destruction is likely to occur.

U.S. District Judge William Conley, with the Western District of Wisconsin, said right-of-way deforestation along portions of the route will destroy the Driftless Area's federally protected wetlands and issued a preliminary injunction (*21-cv-096-wmc*).

Project developers American Transmission Co. (ATC), ITC Midwest and Dairyland Power Cooperative had planned to begin clear-cutting the Wisconsin portion of the nearly $500 million, 101-mile 345-kV line from Dubuque County, Iowa, to Dane County, Wisconsin.

Conservation groups Wisconsin Wildlife Federation, Driftless Area Land Conservancy (DALC), National Wildlife Refuge Association, and Defenders of Wildlife argued in May that the developers and the U.S. Army Corps of Engineers had ignored adverse environmental impacts. They argued that the line's environmental impact statement, prepared by the U.S. Department of Agriculture's Rural Utilities Service, did not comply with the National Environmental Policy Act (NEPA) and that its right-of-way permitting violated the National Wildlife Refuge System Improvement Act.

The groups also said the corps ran afoul of NEPA, the Endangered Species Act and the Clean Water Act by issuing permits for line construction despite known environmental harms. They said the corps failed to meaningfully address project alternatives.

Conley agreed that irreversible environmental damage was likely to occur if the deforestation went ahead as scheduled on wooded wetland areas.

"While defendants assure the court that best construction practices and mitigation will be used, that does not change the fact that some harm will come to the environment," he wrote. "Specifically, even the first stage of construction will involve ground clearing, which in and of itself causes harms that are acknowledged in the environmental impact statement, which the corps signed."

Conley said that the potential damage in this case "relates to the destruction of ecosystems, wetlands, and habitats, and simply awarding damages cannot repair fragile ecosystems that are harmed." He added that "money cannot reverse soil erosion or reintegrate fragmented habitats."

He said the corps's Utility Regional General Permit contains "no evidence of even cursory analysis of the cumulative impact" if the line is built near federal waters.

Conley acknowledged that developers have been clearcutting a 15-mile stretch of the route in northeastern Iowa since April.

But he said ATC, ITC and Dairyland should not have acted as if the line were an inevitability and taken for granted that they would sail through a permitting process. Conley said the developers don't yet have permission to clear or build in the Upper Mississippi River National Fish and Wildlife Refuge, where the line's Iowa and Wisconsin portions meet, and he said the refuge's protected status likely represents the conservation groups' best defense against some line construction.

Conley said developers could have paused their timeline rather than give the groups the minimum 30-day notice of their intent to begin work. He said the "limited" monetary damages of a preliminary injunction "are unlikely to outweigh the permanent damage threatened."

ATC, ITC and Dairyland estimated that a 30-day injunction would lead to $3.1 million in damages and a 60-day injunction would cause them $12.72 million in damages.

Environmental Law and Policy Center attorney Howard Learner, representing the conservation groups, said the injunction halts developers from damaging more than 100 wetlands along the line's path.

He said he was encouraged by Conley's opinion that the Upper Mississippi River Wildlife Refuge is probably an inappropriate backdrop for 20-story transmission towers.

"That will require the federal government agencies to robustly explore and objectively evaluate better, less expensive and less environmentally damaging alternatives. That should have been done before, and, if the District Court's final decision is aligned with the preliminary injunction opinion, then it will be required soon," he said in a statement. "The court's preliminary injunction decision is well-grounded in both law and common sense. It is in the public interest and can better protect both the environment and ratepayers."

The Upper Mississippi River National Wildlife and Fish Refuge | *Driftless Area Land Conservancy*

Learner said ATC and ITC "should hit the pause button" while the court readies a final opinion over the next 30 to 60 days.

In a joint statement, ATC, ITC and Dairyland said while they were "disappointed" with the injunction, it affects fewer than 16 acres of the 87-mile Wisconsin route. The trio said they "voluntarily agreed to avoid construction in these wetlands until Nov. 29 as a showing of good faith and cooperation to the court and other parties," but they also said they would continue project construction on the land unaffected by the injunction.

They said they remain convinced the project stands on its merits and said more than 17 GW of renewable generation is dependent on its construction.

"The Cardinal-Hickory Creek project is needed more today than when initially approved by the Public Service Commission of Wisconsin in 2019," the developers said. "The utilities are committed to completing this project, which will reduce energy costs, improve electric grid reliability, relieve congestion on the transmission system, support decarbonization goals and help support the interconnection of renewable generation in the Upper Midwest."

The Cardinal-Hickory Creek project is the last of MISO's 2011 Multi-Value Projects in line for a ribbon-cutting ceremony. ATC, ITC and Dairyland have been trying since 2012 to build the line; DALC and the Wisconsin Wildlife Federation have been fighting in court for years against the line. (See *Environmental Groups Divided on Cardinal-Hickory Creek Line*.)

The project suffered a separate setback earlier this year when developers ATC and ITC uncovered evidence of encrypted messages between their employees and former Wisconsin Commissioner Mike Huebsch. (See *Former Wisc. Commissioner's Texts Imperil Cardinal-Hickory Creek Line*.) The incident forced the companies to redo the project's certificate of public convenience and necessity. ■

MISO News

MISO Says IMM's Market Recommendations Fair

By Amanda Durish Cook

MISO last week said its Independent Market Monitor was reasonable in proposing four market changes in the 2020 State of the Market report, though two improvements must wait years for the RTO's new market platform to be brought online.

IMM David Patton, Potomac Economics' president, suggested four changes:

- Creating a new uncertainty capacity product that can be deployed instead of out-of-market commitments;
- better matching emergency procedures and pricing of transmission versus capacity emergencies;
- disqualifying wind generation from providing ramping services; and
- developing individual effective load carrying capabilities (ELCCs) for more specific capacity accreditations for distributed resources, load-modifying resources (LMRs), solar generation, and battery storage.

Patton in June underscored transmission congestion, heightened ramping needs, and undervalued capacity prices as areas of concern. (See *MISO Monitor Warns of Ramping Needs, Tx Congestion*.)

MISO Director of Market Design Kevin Vannoy said some of the recommendations were already in MISO's five-year plan and market redefinition outline.

He said uncertainty management is a high priority at MISO, evidenced by the grid operator's development of a 30-minute short-term reserve product and work on a better ramping product. Vannoy said staff will continue to work on a look-ahead commitment tool for generators.

"We're looking at how we can leverage and align our existing products to manage uncertainty," he told stakeholders during a Thursday Market Subcommittee meeting.

However, Vannoy said additional market products to temper uncertainty would probably need to wait four years so that they can be hosted on MISO's new market platform. Staff has repeatedly said the RTO is severely limited on market offerings in the current platform's 1990s era technology.

Vannoy also said MISO will likely have to wait until 2025 to remove wind generation's eligibility to provide ramping services. He said the change is dependent on MISO moving its market operations to the new platform.

The grid operator has already drawn a clearer distinction between pricing during capacity emergencies and transmission emergencies,

MISO IMM David Patton | *APPrO*

Vannoy said, pointing to an August FERC filing that specifies its $3,500/MWh value of lost load applies to capacity emergencies only, not those caused by felled transmission towers (*ER21-2801*).

MISO agreed that it could use more tailored ELCCs for its non-traditional resources.

"MISO agrees with further evaluation and development of accreditation methodologies for [LMRs], intermittent resources and other resource types with high level of variability and uncertainty," Senior Manager Lynn Hecker said.

The RTO said it will probably file with FERC sometime next year to create more specific ELCCs. ■

NYISO News

NYISO Looks at Capacity Market Change Cost Impacts

By Michael Kuser

The cost impacts of proposed wholesale capacity market changes topped the agenda of NYISO's Installed Capacity (ICAP) Market Issues Working Group on Nov. 2.

NYISO discussed the *methodology* used to measure the market impacts of implementing changes to buyer-side mitigation (BSM) rules, while the ISO's Market Monitor, Potomac Economics, *presented* an analysis of the effects of capacity accreditation on consumers.

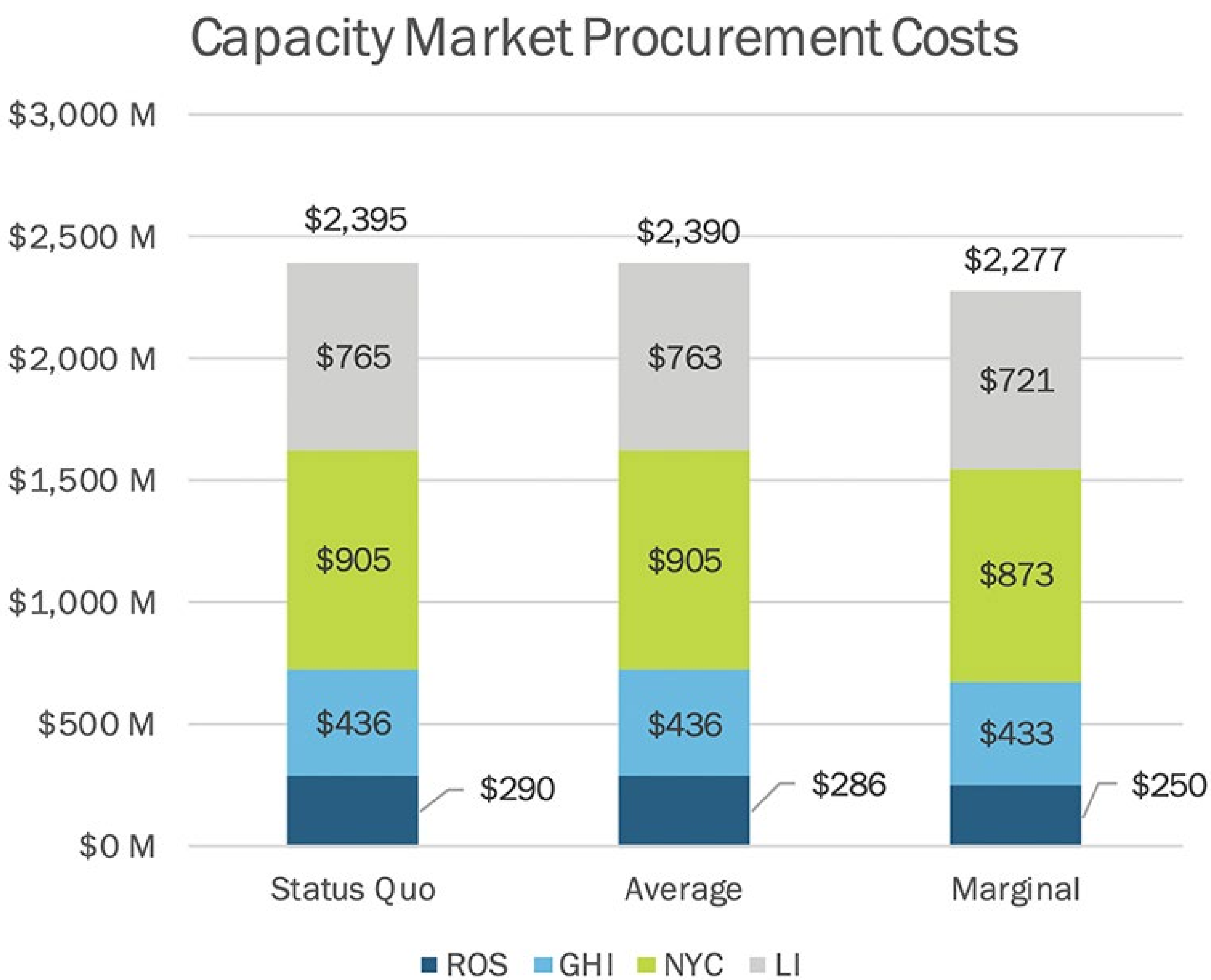
In 2026, capacity market procurement costs would be approximately $5 million below the status quo case using an average accreditation approach, while costs would be $119 million lower using the marginal accreditation approach proposed by the NYISO, Tariq N. Niazi, NYISO senior manager for consumer impact analysis, told the ICAP group.

The ISO is developing a proposal to help keep the capacity market just and reasonable as thousands of megawatts of state-solicited resources come online in New York. The Climate Leadership and Community Protection Act (CLCPA) requires the state to procure large amounts of renewable energy to get to zero-emission electricity by 2040, forcing the wholesale electricity market to adapt.

Several stakeholders forced some new business to the top of the agenda regarding BSM, asking the ISO to explain a request from the Price Responsive Load Working Group for information from demand response curtailment providers.

The issue stems from NERC and FERC analysis focused on the effect of load-management and load-shed programs on fuel supply infrastructure.

The NERC Standards Committee last month voted to delay approving the draft standard authorization request (SAR) developed in response to a preliminary joint report with FERC on the catastrophic winter storm events in Texas last February until after the final report is published. (See *NERC Standards Committee Delays Action on Cold Weather SAR*.)



Cost savings may be greater than shown because of the use of Equivalent Demand Forced Outage Rate (EFOR) to determine fossil unforced capacity in all cases. | *NYISO*

NYISO News

The ISO is working on the issue, said Zachary Smith, manager for capacity market design.

One stakeholder asked whether NYISO considers the study assumptions for DR differently from special case resources, which require a 21-hour notice before dispatch.

"I think we're looking for false precision in the analysis that we're doing," Michael DeSocio, NYISO director of market design, said. "We're not running an economic expansion analysis here. The analysis is intended to indicate directionally what would happen. The analysis we'll see from Potomac goes a step further, but again there are limitations on how granular we're able to get in these analyses."

Accreditation: Consumer Impact

A marginal accreditation approach results in more efficient signals for investment and lower consumer costs than the status quo or an average approach, Joe Coscia of Potomac Economics said.

Capacity market signals can help guide investment in policy resources at the lowest cost to consumers when renewable energy credits supplement wholesale market revenues, the analysis said.

Efficient accreditation will have more impact as the CLCPA requires larger quantities of investment, and the Monitor supports NYISO's proposal to apply a marginal accreditation approach to all resources, Coscia said.

"You can't look at these capacity credit numbers in a vacuum. They are always a product of the resource mix in the case being studied," he said.

Stakeholders have asked about the period beyond 2030 that Potomac was not able to model explicitly in this study, prompting Coscia to share thoughts on factors that would intuitively tend to affect the results going forward, given the logic of the model.

"All of these things in the context of our model would tend to increase the divergence between accreditation methods going forward," Coscia said. "Those include larger renewable and storage targets, and the reason would be that with more investment decisions that need to be made, the cost of making inefficient investment decisions is larger."

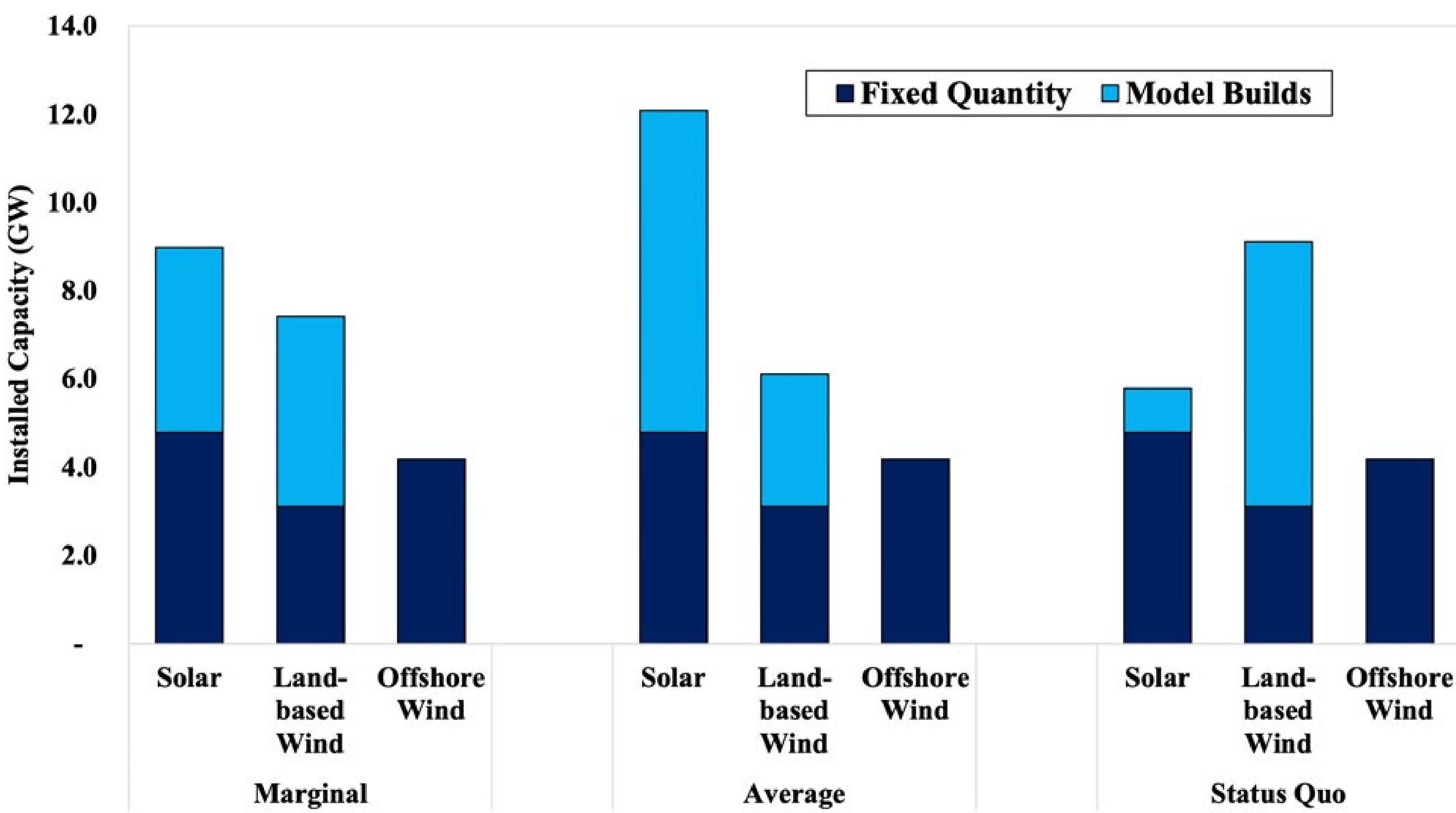
Any policy requiring replacement of a larger measure of peaking resources would tend to increase the importance of accreditation, he said.

Consumer savings under a marginal approach would be greater at higher capacity prices because the differences in capacity payments would be magnified, which affects both the incentive effects as well as the total payment differences between methods, Coscia said.

"Higher load growth or changes in load pattern would tend to increase the importance of efficient accreditation, whether that's just high load going forward or maybe something like a shift towards a winter peaking system," he said.

Finally, application of enhanced accreditation methods to other technologies such as gas-only units or inflexible units would tend to produce values for those resource types that would decline more under a marginal approach than under an average approach or the status quo, which doesn't apply any discount to those resources — also increasing the consumer savings under a marginal approach.

"For these reasons we believe that the advantage of marginal accreditation over other methods is likely to increase beyond 2030, and so the numbers that we presented here likely are conservative," Coscia said. ■



Marginal accreditation encourages a balanced mix of intermittent.renewables compared to other approaches. | *Potomac Economics*

Con Edison Q3 Earnings up on Clean Energy Growth

By Michael Kuser

Consolidated Edison on Thursday reported 2021 third-quarter net income of $538 million ($1.52/share), up 9.1% compared with $493 million ($1.47/share) in the same period a year ago, citing strong performance in its Clean Energy Businesses unit.

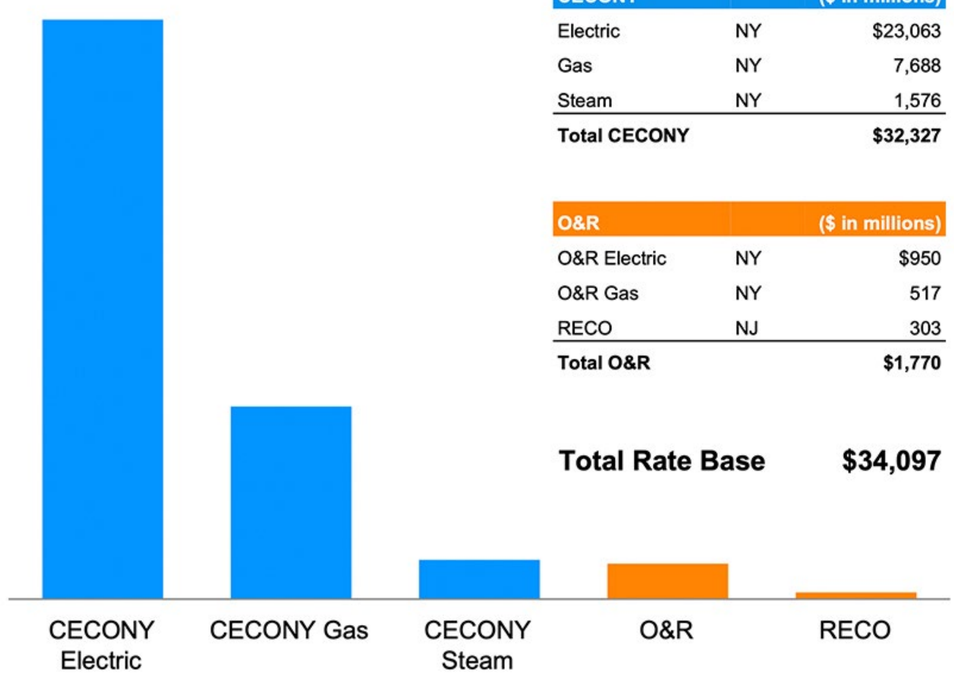
For the first nine months of 2021, net income for common stock was $1.122 billion ($3.23/share), an increase of 6% compared with $1.058 million ($3.17/share) over 2020.

"Our energy systems delivered world-class reliability this summer. In response to several storm events and heat waves, our team efficiently restored affected customers and are managing the costs of these efforts," CEO Timothy Cawley said in a *statement*.

Protecting customers from climate change makes the company's integrated planning and clean energy investments more critical than ever, he said.

"We continue to lead the transition to a clean energy future, evidenced during the quarter by our solicitation for large energy storage projects, which will allow our customers to maximize the benefits of renewable energy," Cawley said.

The company *reported* its Clean Energy Businesses having 3,004 MW of utility-scale renewable energy production projects in service (2,988 MW) or in construction (16 MW), and 72 MW of such projects behind the meter in service (62 MW) or in construction



CECONY		($ in millions)
Electric	NY	$23,063
Gas	NY	7,688
Steam	NY	1,576
Total CECONY		**$32,327**

O&R		($ in millions)
O&R Electric	NY	$950
O&R Gas	NY	517
RECO	NJ	303
Total O&R		**$1,770**

Total Rate Base $34,097

Composition of Con Edison's regulatory rate base as of Sept. 30. | *Con Edison*

(10 MW). The business unit generated 1,932 kWh of electricity from solar projects for the three months ending Sept. 30, up nearly 16% compared to 1,667 kWh for the same period in 2020.

Rate plans for investor-owned utilities in New York allow them to defer costs resulting from a change in legislation, regulation and related actions that have taken effect during the term of the plans once the costs exceed a specified threshold. The total reserve increases to the allowance for uncollectible accounts from Jan. 1, 2020, through Sept. 30 — reflecting the impact of the COVID-19 pandemic for Consolidated Edison Company of New York (CECONY) electric and gas operations and Orange and Rockland Utilities (O&R) electric and gas operations — were $235 million and $7 million, respectively.

Dominion's OSW Project to Cost $9.8B, up from $8B

Load Returning to Pre-pandemic Level, Company Says in Earnings Call

By Martin Berman-Gorvine

Dominion Energy *said* Friday the projected cost of its 2.6-GW Coastal Virginia Offshore Wind (*CVOW*) project has increased by more than 20% to $9.8 billion, citing "commodity and general cost pressures."

The company announced the projected cost increase on the day it reported a near doubling of third quarter profits and filed a request for approval and certification of the CVOW project with the Virginia State Corporation Commission.

In September 2019 Dominion announced a "pre-engineering" estimated cost of about $8 billion.

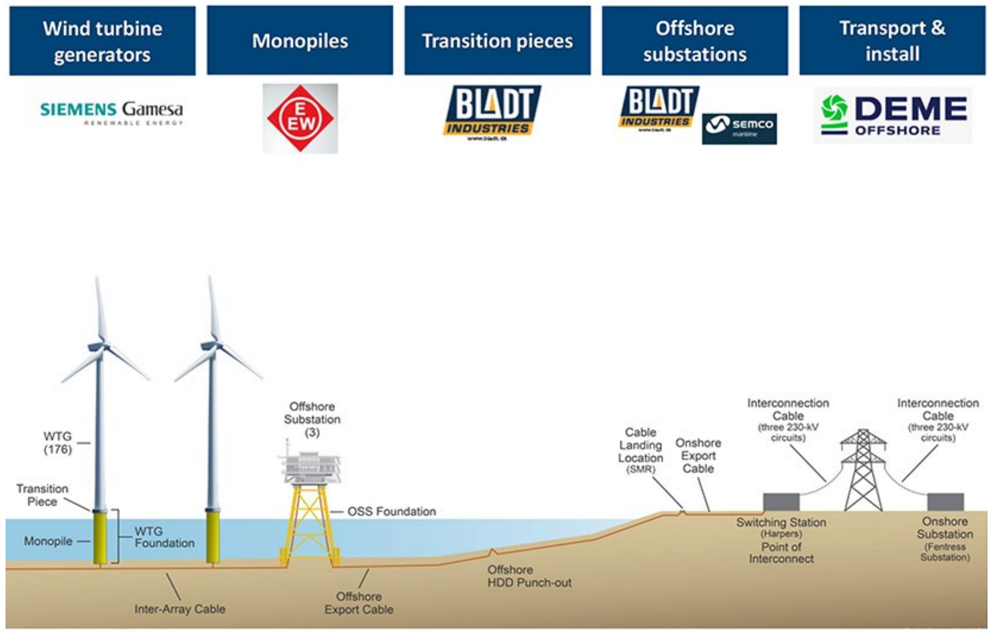
"Since that time through the process of detailed engineering and, most importantly, through competitive solicitations for all components and services, we've now developed a detailed budget of approximately $10 billion," CEO Bob Blue told analysts during the third quarter earnings call. "The cost increase can be attributed to, among other things, commodity and general cost pressures — as seems to be the case across a number of industries right now — and the completion of the conceptual design phase for the onshore transmission route."

Blue said the company has meet the three tests required for Dominion to qualify for cost recovery via a rider on customers' bills: using competitive procurements; a projected levelized cost of energy (LCOE) below the $125/MWh maximum set in the Virginia Clean Economy Act (VCEA), and a projected start to construction before 2024.

Dominion asked the SCC to classify many of the details of its filing as "extraordinarily sensitive," citing the commercial value of its negotiated contracts and terms with vendors. The filing includes information on "costs, contractor selection, project components, transmission routing, capacity factors and permitting."

The company said the filing keeps it on its scheduled timeline to leap from its current two-turbine, 12-MW pilot project in federal waters off Virginia Beach to the planned 2.6 GW wind farm.

Last December, Dominion submitted the plans for the larger project to the Bureau of Ocean



Dominion Energy's contractors for its 2.6-GW Coastal Virginia Offshore Wind project | *Dominion Energy*

Energy Management, which is expected to complete an environmental study and reach a decision by June 2023. The company is also expecting a final order approving the project from the SCC in the third quarter of next year. If all goes as planned, onshore construction will begin in the third quarter of 2023, followed by offshore construction in the second quarter of 2024 with construction finished in late 2026.

The company says the project will create approximately 900 jobs and have $143 million in economic impact annually during construction, increasing to approximately 1,100 jobs and almost $210 million in economic impact annually during its operation. On Oct. 25, Siemens Gamesa held a ceremony at the Portsmouth Marine Terminal celebrating the launch of the first offshore wind turbine OEM blade manufacturing facility in the U.S. The plant's initial output will go to the Dominion project. (See *Virginia Builds out OSW Supply Chain with Turbine Blade Plant*.)

News of CVOW's $1.8 billion cost increase sparked criticism on social media. A ProPublica-Richmond Times-Dispatch investigation last year *reported* that Dominion lobbied for changes to the VCEA that increased the maximum cost of CVOW from $7.3 to $9.8 billion.

"Dominion lobbyists snuck in an extra $2 billion on the wind cost cap in the VCEA at the last minute. Now all of the sudden their costs include an extra $2 billion…?" tweeted Brennan Gilmore, executive director of *Clean Virginia*.

"Lo and behold: The ceiling for rate base is the price of the project," responded former Montana regulator Travis Kavulla, now vice president of regulation for NRG Energy.

Blue said the LCOE of the offshore wind farm is estimated at $87/MWh but could be reduced to $80/MWh if Congress approved proposed OSW tax credits included in the $1.8 trillion spending bill pending before the House. (See related story, Infrastructure bill recap and reaction.)

Although construction costs are higher than anticipated, Blue said that — based on data from the pilot turbines — the company now assumes a lifetime capacity factor of 41.5% for CVOW, up from an earlier estimate of 43.3%. When asked about the potential impact of the Republican victory in last week's Virginia elections on these plans, Blue said Dominion Energy "has maintained constructive relationships with members of both parties," and that there is "a bipartisan commitment to jobs and

PJM News

economic growth." Referring to the Siemens Gamesa announcement, he added: "Both parties deserve credit for that kind of job creation in Tidewater Virginia. We would expect that that's going to continue going forward."

Dominion Energy also recently filed a rider with the Virginia SCC that included about 1,000 MW of solar and battery storage, Blue said. The company expects a final order from the agency for this project, with its planned $1.4 billion capital investment, by the second quarter of next year.

Q3 Results

In addition to highlighting its offshore wind and solar projects during the earnings call, Dominion officials said that the utility company is nearing its pre-pandemic normal in electricity sales.

The company expects to see electric sales in its Virginia and South Carolina service territories rise by 1% to 1.5% per year, similar to growth rates before COVID-19 struck, CFO Jim Chapman said.

Dominion Energy *reported* $654 million ($0.79/share) in net income, nearly double the $356 million ($0.41/share) in the third quarter of 2020.

Chapman said the company expects to grow its earnings per share at a rate of at least 6.5% annually through 2025, thanks to a $32 billion, five-year growth capital plan, more than 80% of which is focused on decarbonization. Going forward, he added, investors should expect to see "compelling earnings and dividend growth combined with the largest regulated decarbonization opportunity in the industry, and an unyielding focus on extending our track record of successful projects, regulatory and financial performance."

Assuming normal weather for the rest of 2021, the company says, it expects full-year results to be above the $3.85/ share midpoint of its 2021 estimated guidance.

The SCC is due to review a comprehensive settlement agreement in the company's pending triennial base rate case, now that stakeholders have weighed in. Blue said a decision is expected by the end of the year. If the commission approves it, the agreement will resolve the ongoing review of the company's earnings over the past four years, while generating $330 million in one-time refunds on customer bills, a $309 million offset as part of the Customer Credit Reinvestment Offset (CCRO) mechanism, and a $50 million rate reduction going forward. The CCRO "offsets the customer bill credit amount that the utility has invested or will invest in new solar or wind generation facilities or electric distribution grid transformation projects for the benefit of customers," according to Virginia statute. ■

FirstEnergy Announces $3.4 Billion in New Equity Financing

Sets Long-term Earnings Growth Rate of 6-8%

By John Funk

FirstEnergy on Sunday announced $3.4 billion in new equity financing from two global investors that the company believes will position it for a long-term earnings-per-share growth rate of 6 to 8%.

The company announced that it will issue $1 billion in common equity to New York City-based Blackstone Infrastructure Partners at $39.08/share and appoint a Blackstone representative to its board of directors no later than its next annual meeting.

FirstEnergy further announced that it had agreed to sell a 19.9% minority interest in its transmission subsidiary First Energy Transmission (FET) to Toronto-based Brookfield Super-Core Infrastructure Partners for $2.4 billion in cash.

FET is a holding company for FirstEnergy's three FERC-regulated transmission subsidiaries that operate 24,000 miles of high-voltage power lines across six states. The sale of a minority interest in FET to raise cash has been under discussion for several months.

Under questioning from analysts at FirstEnergy's third-quarter earnings call two weeks ago, CFO Jon Taylor described the interest in FET as "very strong, and preliminary indications are very supportive of our financial plan and targets."

The sale, subject to FERC approval and review by the Committee on Foreign Investments in the U.S., is expected to close in the first half of 2022, FirstEnergy said.

The company believes the transactions will enhance its credit profile, which was recently returned to investment-grade, and provide enough cash to address all of its needs for new equity now and in the near future. The company is planning major grid upgrades.

In a statement accompanying the news of the equity sale and minority interest sale, FirstEnergy CEO Steven Strah called the two agreements "key catalysts to fulfill our long-term strategy and drive smart grid and clean energy initiatives for our customers and communities."

Donald T. Misheff, non-executive chairman of FirstEnergy's board, said, "The entire board, including our voting and non-voting members, unanimously supports these important actions.

"This represents a pivotal moment in the company's trajectory and positions FirstEnergy to drive shareholder value." ■

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PSEG Eyes Federal Tax Credits for Nuclear Plants

Izzo: Plans for Offshore Wind Transmission Links Submitted to BPU

By Hugh R. Morley

PSEG is hoping that an eight-year energy tax credit in President Biden's Build Back Better legislation will support the company's three nuclear plants while New Jersey's offshore wind industry — and the utility's place in it — develops and the sector begins supplying clean energy.

On the utility's third quarter earnings call Nov. 2, CEO Ralph Izzo said that the company is "hopeful" that Congress will pass the budget reconciliation legislation soon. The bill would provide a production tax credit of $15/MWh, with the value declining over time, he said.

"Moving forward, there needs to be broad recognition at both the state and federal level of the value of nuclear's zero-carbon attributes, both for the quality of air today and the climate tomorrow," Izzo told the call. "To avoid backsliding for decades to come, we need to ensure that the long-term viability of New Jersey's nuclear generation is preserved as we bring more clean energy resources into the mix."

Biden has struggled to secure the votes for passage of the legislation, a spending package of about $1.75 trillion, in large part because of differences between Democratic moderates and progressives about how big the bill should be and which elements should take priority. A press conference Nov. 1 by Sen. Joe Manchin (D-W.Va.) once again put the bill's passage in doubt, but at a press conference in Glasgow the next day, Biden said he believes Manchin will sign on.

If enacted, the subsidies would support Hope Creek nuclear power plant, which PSEG owns and operates, and the Salem 1 and Salem 2 plants, which the utility operates and co-owns with Exelon. All three plants are located in South Jersey.

The state's Board of Public Utilities (BPU) in April awarded the company $300 million in subsidies for the three facilities at $10 MWh under the state's Zero-Emission Certificate (ZEC) program. (See *NJ Nukes Awarded $300 Million in ZECs*.) Program rules state that if federal subsidies are awarded to the plants, the state subsidies would be reduced, Izzo said.

New Jersey is looking to cut its emissions 80% from 2006 levels by 2050; Izzo said, "There's widespread recognition that if we're going to make progress, it's got to be based upon the existing nuclear fleet still being around."

Building Offshore Transmission Lines

To advance the state's uptake of clean energy, Izzo also reported that PSEG recently submitted proposals to PJM and the BPU for several potential transmission solutions to deliver electricity generated by offshore wind projects to the power grid. The company announced last month that it had submitted nine proposals, collectively called Coastal Wind Link, under a competitive solicitation opened by the BPU in April. The solicitation is expected to be concluded late next year. (See *New Jersey Seeks OSW Transmission Ideas*.)

The proposals include ways to "create a grid out in the ocean" and suggestions on how to tie it to the grid on land in New Jersey, Izzo said. The package also outlines the "upgrades that are needed on land to support this injection of new supply" of energy, Izzo said.

The utility submitted the proposals with Danish offshore wind developer Ørsted, PSEG's partner in Ocean Wind 1, one of three offshore wind projects approved so far by the BPU. The approved projects total 3,758 MW, and the BPU expects to hold three more solicitations, with a target of deploying 7,500 MW of offshore wind by 2035.

PSEG *reported a net loss of $1,564 million* ($3.10/share), a year-over-year decline from net income of $575 million ($1.14/share) in the third quarter of 2020. Non-GAAP operating earnings for the second quarter of 2021 were $495 million, ($0.98/share), compared to non-GAAP operating earnings of $488 million ($0.96/share) for the third quarter of 2020.

The loss is the result of a "pre-tax impairment loss" of $2.17 billion that stemmed from the announced sale of the company's fossil generating fleet, Izzo said. (See *PSEG Close to Fossil Asset Sale*.) ■

PSEG hopes to receive production tax credits for its Hope Creek and Salem nuclear plants. | *Public Service Enterprise Group*

PJM PC/TEAC Briefs

Planning Committee

Winter Weekly Reserve Target Endorsed

PJM stakeholders unanimously endorsed the results of the 2021/22 winter weekly reserve target analysis at the Planning Committee's meeting Nov. 2.

Patricio Rocha Garrido, PJM | © RTO Insider LLC

Patricio Rocha Garrido, of PJM's resource adequacy planning department, *reviewed* the results of the analysis, saying the numbers differed slightly from 2020/21 because of more uncertainty in the modeling. Rocha Garrido first presented the analysis numbers at last month's PC and Operating Committee meetings. (See "Winter Weekly Reserve Target Update," *PJM Operating Committee Briefs: Oct. 7, 2021*.)

Members also unanimously endorsed the analysis at Thursday's OC meeting. (See related story, *PJM Operating Committee Briefs: Nov. 4, 2021*.)

The targets for December, January and February are 24%, 27% and 21% respectively, compared to 23%, 27% and 23% last year. Rocha Garrido said the December value increased slightly because PJM sees more load uncertainty in the modeling, while February's decrease is a result of less load uncertainty.

PJM staff use the targets, which are part of the *reserve requirement study*, to help coordinate planned generator maintenance scheduling over the winter months. Rocha Garrido said the purpose of the targets is to "cover against uncertainties" related to load and forced outages, ensuring that the loss-of-load expectation (LOLE) for winter is "practically at zero."

The winter weekly reserve target for each month is the highest weekly reserve percentage, rounded up to the next integer value. Rocha Garrido said the targets are only recommendations to PJM's operations department.

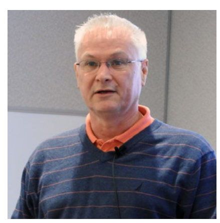
Manual Endorsements

Several manual updates stemming from the biennial cover-to-cover review also won unanimous stakeholder endorsement. The updates were first presented at the October PC meeting. (See "Manual First Reads," *PJM PC/TEAC Briefs: Oct. 5, 2021*.)

Michael Herman, PJM | © RTO Insider LLC

Michael Herman, of PJM's transmission planning department, *provided* a review of *Manual 14B: PJM Region Transmission Planning Process Update*, including the addition of a new section that features details around the incorporation of end-of-life (EOL) needs in the Regional Transmission Expansion Plan, which were part of the tariff attachment M-3 discussions.

FERC in December rejected a stakeholder proposal to move EOL projects under PJM's planning authority, siding with transmission owners who argued that it would violate their rights. (See *FERC Rejects PJM Stakeholder EOL Proposal*.) The commission also accepted the TO sector's tariff amendments concerning EOL projects in August 2020, rejecting arguments in rehearing requests by more than a dozen load-side stakeholders. (See *FERC Accepts PJM TOs' End-of-life Revisions*.)



John Reynolds, PJM | © RTO Insider LLC

John Reynolds, of PJM's resource adequacy planning department, *reviewed* minor changes to *Manual 19: Load Forecasting and Analysis*. Reynolds said the most significant change was adding battery storage to the list of forecasted items in the load forecast model overview in Section 3.1, which already includes distributed solar generation, plug-in electric vehicles and historical weather patterns to estimate growth in peak load and energy use.

Joseph Hay, of PJM's infrastructure coordination department, *reviewed* the updates to *Manual 14F: Competitive Planning Process*, saying the changes were necessary to correct the proposal fee structure in the manual to conform to the Operating Agreement.

Hay said the language in Manual 14F was not in agreement with the latest changes to the OA, which states, "All proposals in any RTEP window are subject to a nonrefundable deposit of $5,000, except for project proposals submitted with cost estimates of $5 million or less. In addition to the $5,000 nonrefundable deposit, the proposing entity must pay all actual costs incurred by PJM to evaluate the submitted project proposal."

The manual changes now go to the Nov. 17 Markets and Reliability Committee meeting for endorsement.

Transmission Expansion Advisory Committee

Generation Deactivation Notification

Phil Yum of PJM *provided* an update on recent generation deactivation notifications.

PJM has received a "good amount" of deactivation requests in the last month in the PPL transmission zone, he said. Those requests include:

- Williamsport CT 1 and 2 oil-fired units, with a total of 26.6 MW of generation;
- West Shore CT 1 and 2 oil-fired units, 28 MW;
- Lock Haven CT 1 oil-fired unit, 14 MW;
- Jenkins CT 1 and 2 oil-fired units, 27.6 MW; and
- Fishbach CT 1 and 2 oil-fired units, 28 MW.

The requested deactivation date for these units is April 1, 2022.

Several other units in the PPL transmission zone have a requested deactivation date of June 1, 2022. Those units include:

- Martins Creek CT 1, 2 and 3 oil-fired units, 57.3 MW;
- Harrisburg CT 1, 2 and 3 oil-fired units, 41.1 MW; and
- Allentown CT 1, 2, 3 and 4 oil-fired units, 56 MW.

Four different units in the Dominion transmission zone were also added to the deactivation list, with a requested date of June 1, 2023. They include:

- Rockville CT diesel unit, 4 MW;
- Lanier CT 1 diesel unit, 7 MW;
- Dinwiddie CT 1 diesel unit, 3 MW; and
- Weakley CT diesel unit, 7 MW.

A reliability analysis was completed for all units, and no violations were identified. ■

— *Michael Yoder*

PJM News

PJM MIC Briefs

RTO to Propose Review of Regulation Market

Stakeholders at last week's Market Implementation Committee meeting heard PJM's plan to win endorsement of a solution to deal with its regulation mileage ratio calculation problem after two proposals failed last month.

Adam Keech, PJM | © *RTO Insider LLC*

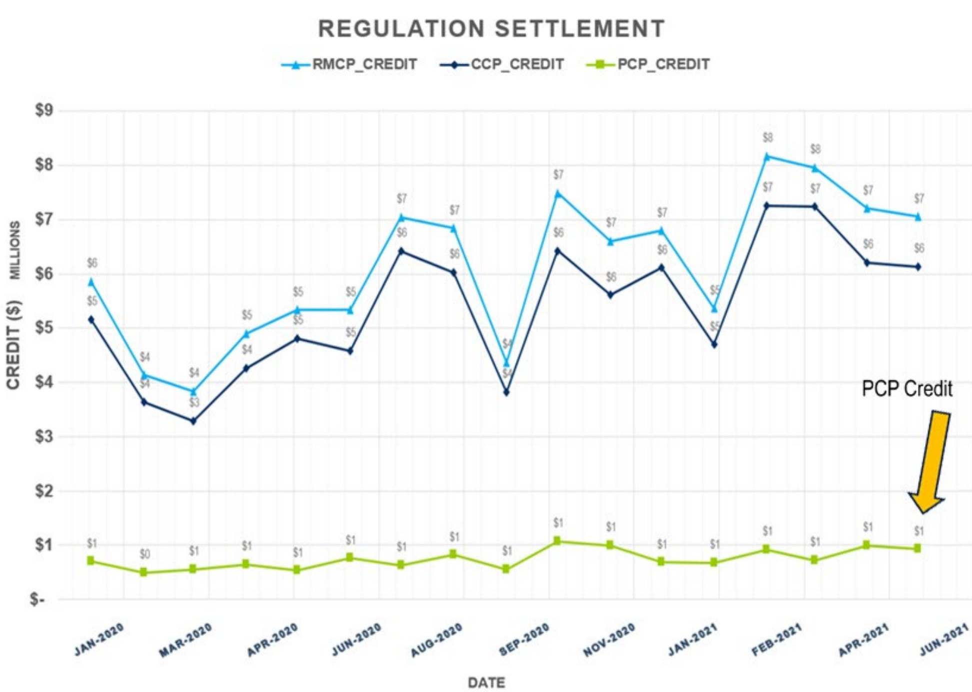
Adam Keech, PJM's vice president of market design and economics, discussed the "logical next steps" of the proposal, which seeks to fix the calculation of the ratio to prevent an undefined condition.

PJM's performance-based regulation market splits the dispatch signal in two: RegA for slower-moving, longer-running units; and RegD for faster-responding units like batteries that operate for shorter periods. If a signal is "pegged" high or low for an entire operating hour, the corresponding mileage would be zero for that hour. There has been an increased frequency of RegA signal pegging and times the RegA signal is pegged for extended periods, creating a divide-by-zero error in the calculation of the mileage ratio.

The RTO's proposal, which called for setting the RegA dispatch mileage floor at 0.1 instead of zero, failed in a sector-weighted vote of 2.12 (42.4%) at the October Markets and Reliability Committee meeting, short of the 3.33 (66.6%) threshold for endorsement. A separate proposal from the Independent Market Monitor, which called for a cap of 5.5 instead of 0.1, also failed, receiving a sector-weighted vote of 3.07 (61.4%). (See "Regulation Mileage Ratio Fails," *PJM MRC/MC Briefs: Oct. 20, 2021*.)

Keech said PJM heard stakeholders' desire during the voting process to discuss "more systemic issues" with the regulation market and to examine those issues more closely, so it brought forward a proposal to begin a broader market review. Danielle Croop, senior lead market design specialist at PJM, reviewed the *problem statement* and *issue charge*. Keech said they were similar to the ones endorsed and created the former *Regulation Market Issues Senior Task Force* that last met in 2017.

The key work activities include regulation market education, evaluating the benefits factor curve and proscribed RegA/RegD commitment percentages, and proposing any modifications to the regulation market to address issues raised in the evaluation.



PJM's regulation market clearing price credit since January 2020 | *PJM*

Keech said the review would utilize a new senior task force reporting directly to the MRC. PJM plans on conducting a first read of the problem statement and issue charge at the Nov. 17 MRC meeting.

Once the problem statement and issue charge are approved, Keech said, another vote would take place on the short-term solution proposals from PJM and the Monitor that were not endorsed.

"We could go for a vote of the short-term solutions knowing we have the larger regulation market review that we are going to commence," Keech said.

Fuel-cost Policy Standards and Penalties

Melissa Pilong of PJM *provided* a first read of an RTO/Monitor *proposal* addressing clarifications to fuel-cost policy standards in *Manual 15* and *Operating Agreement Schedule 2* penalty language developed through the Cost Development Subcommittee.

Pilong said the proposal includes a combination of clarifications and language for more elaboration on PJM's fuel-cost policies that resulted after the RTO examined the fallout from the February winter storm in Texas and other parts of the South and Midwest.

The proposal calls for market sellers of generation units to verify that all intraday offer triggers are specified in the unit's fuel-cost policy. Market sellers will also have to verify that weekend or holiday natural gas estimation practices match either the default assumptions in the PJM *Fuel Cost Policy Guidelines* contained in Manual 15 or specify estimation practices in the unit's policy.

The Manual 15 updates include changes to the intraday update triggers. In order to opt into intraday offers, Pilong said, market sellers need to have a one-time trigger to update the maximum allowable cost offer.

The committee will be asked to endorse the proposal at its next meeting. PJM is seeking final endorsement by the Members Committee in February and a FERC filing following approval by the Board of Managers.

Manual 6 Revisions

Emmy Messina, senior engineer with the PJM market simulation department, *presented* a first read of conforming changes to *Manual 6* resulting from the endorsement of a proposal to address the RTO's auction revenue rights and

PJM News

financial transmission rights at the October MRC meeting. (See *Stakeholders Endorse PJM ARR/FTR Market Changes*.)

Messina said the changes would only impact Manual 6 and include language for bid limits and the network model user guide. They would update section 6.6 to reflect an increase of bid limits from 10,000 to 15,000 per corporate entity, auction round and period in FTR auctions. Section 9.1 would also be updated to direct stakeholders to a new network model user guide on the FTR section of the PJM website to get additional information on the auction.

The committee will be asked to endorse the revisions at its next meeting.

Regulation for Virtual Combined Cycles

Michael Olaleye, senior engineer with PJM's real-time market operations, *provided* a first read of a *proposal* by Vistra to revise to *Manual 12* addressing regulation for virtual combined cycle units.

The issue charge was originally endorsed at the May MIC meeting. (See "Virtual Combined Cycle Regulation Issue Charge Endorsed," *PJM MIC Briefs: May 13, 2021*.)

Units that are modeled virtually by PJM can sometimes receive regulation awards from the market clearing engine that vary, Olaleye said, which Vistra has been experiencing with some of its units. When a combined cycle unit is modeled as multiple virtual units, there is a possibility for unbalanced or unequal regulation awards to each unit by the engine.

Vistra's proposed enhancement to performance group scoring calls for calculating the "hourly" score and extending it to each market resource with an assigned regulation for the given hour. It also calls for PJM to also calculate the "historic" performance score and extend it to each market resource in the performance group.

Olaleye said the enhancements would ensure that all resources of the performance group have the same historic performance score, which should fix the regulation clearing calculation problem in the software.

The committee will be asked to endorse the proposals at its next meeting. ■

— Michael Yoder

pjm

Fuel Cost Policy Guidelines

Review Date_______________ Fuel Cost Policy ID # _______________ Replacement FCP ID # ________

☐ OPTIONAL: Contact Information (Name, phone number, email, unit information including ID and name)

Unit Name: ______________________ Unit ID #: ______________________

Unit type: ______________________ Fuel Type: ______________________

☐ $0 Cost Policy (Section VII) As of September, 2020, true $0 cost offers no longer require a policy. Negative cost offers must still submit a policy outlining the use of RECs and/or PTCs.

☐ Fuel Costs (Section II)
- ☐ Power Purchase Agreement (PPA)
- ☐ Affiliate Supplier(s)______________________
- ☐ Inventory (AND/OR) ☐ Replacement Cost
- ☐ Spot (AND/OR) ☐ Contract
- ☐ Transportation
- ☐ Natural Gas – Define Liquidity, GD1/GD2 regardless of IDO optionality
- ☐ Wind – RECs and PTCs information must be included
- ☐ Hydro – Pumped Storage Cost may be > $0 / Run of River Hydro Cost =$0
- ☐ Solid Waste, Biomass, Landfill Gas – Cost includes negative fuel prices if applicable

☐ Offer update methodology and triggers (Section II)
- ☐ Day-Ahead ☐ Re-bid
- ☐ Intra-day ☐ Multi-day

☐ Intraday Optionality (Section III)
- ☐ Opt-out ☐ Opt-in
- ☐ Intra-day validation (required)
- ☐ Secondary trigger (optional)

☐ Start-up, No-load, and Incremental Heat Input Value (Section IV)
- ☐ Source of values
- ☐ Frequency of update
- ☐ Unit-specific Performance Factor (value other than 1)

☐ Emissions Rates and Allowances - for all non-zero polices, state if included (Section V)
- ☐ Not Utilized ☐ Source and update frequency of rates
- ☐ Source and update frequency of allowances

☐ Numerical Example – not required for $0 offers (Section VIII)

☐ Documentation Language

The following information was previously required to be included in fuel cost policies. If a policy is being edited for other reasons, please remove all references to the following items. However, if no other edits are being made to the policy, these sections may remain in place.

☐ Maintenance Adders and Operating Costs (VOM)
☐ 10% Adder

PJM © 2021 www.pjm.com 1 | Page

PJM's fuel cost policy form. | *PJM*

Scenario 1: Both units provided regulation service but different hourly integrated performance score

	Unit 1	Unit 2
Reg MW	10	10
Unit Hourly Performance Score	0.95	0.85
Performance Group Historic Performance Score	0.9	0.9

Scenario 2: Unit 2 is on outage but unit 1 provided regulation

	Unit 1	Unit 2
Reg MW	10	0
Unit Hourly Performance Score	0.95	Null
Performance Group Historic Performance Score	0.95	0.95

PJM's examples of proposed performance group scoring using the historic performance score calculation. | *PJM*

PJM News

PJM Operating Committee Briefs

Synchronous Reserve Deployment Endorsed

Stakeholders at last week's Operating Committee meeting endorsed a *PJM* proposal seeking to improve the deployment of synchronized reserves during a spin event.

The proposal, which was developed from discussions in the Synchronized Reserve Deployment Task Force (SRDTF), was endorsed with 164 members voting in favor (72%). PJM first presented the proposal at last month's OC meeting. (See "Synchronous Reserve Deployment Initiative," *PJM Operating Committee Briefs: Oct. 7, 2021*.)

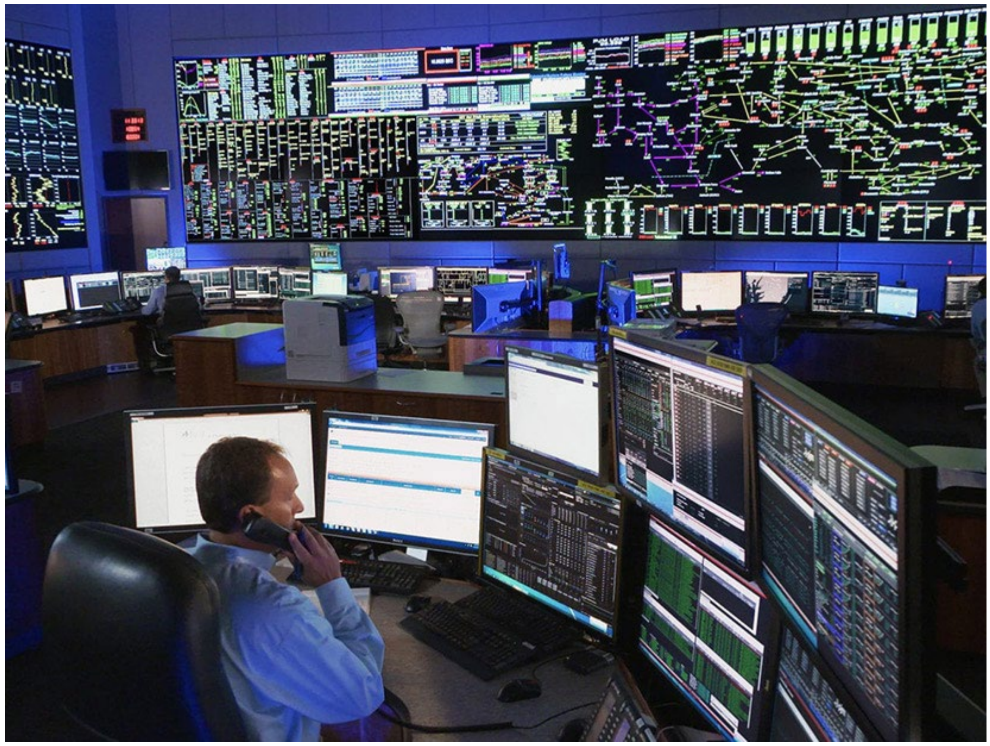
Ilyana Dropkin, an engineer in PJM's performance compliance department, *provided* a review of the task force initiative endorsed at the March OC meeting. Stakeholders were educated about synchronized reserves and created a *matrix* to develop proposals through the task force. (See *PJM OC Endorses Synchronized Reserve Discussion*.)

Synchronized reserve events are emergency procedures triggered by PJM to maintain grid reliability in accordance with *NERC*'s Resource and Demand Balancing (BAL) standards. PJM invokes those procedures under conditions such as the simultaneous loss of multiple generating units or a sudden influx of load.

The SRDTF examined ways to secure controlled deployment of synchronized reserves throughout emergency events by using tools such as real-time security-constrained economic dispatch (RT SCED) to maintain consistent pricing and dispatch signals. The goal was to ensure BAL compliance during the recovery process and maintain a reliable transition in and out of emergency events and to define clear rules and expectations that address how PJM operators approve RT SCED cases around a synchronized reserve event.

The task force developed two different proposals: PJM's intelligent reserve deployment (IRD) proposal, and another by the Independent Market Monitor. In a nonbinding poll taken by stakeholders, PJM's proposal received 75% support, while the IMM's received 9% support. Sixteen percent of stakeholders preferred the status quo.

Michael Zhang, senior lead engineer in PJM's markets coordination department, *reviewed* the PJM proposal. Zhang said no changes were made to the proposal since it was first presented at the October OC meeting.



PJM control room | *PJM*

The IRD proposal is a SCED case that simulates the loss of the largest generation contingency on the system and for which approval of the case will trigger a spin event, Zhang said.

The PJM proposal calls for taking the megawatts of the largest generation contingency and adding them to the RTO forecast to simulate the unit loss, Zhang said. PJM would then be allowed to flip condensers and other inflexible synchronized resources cleared for reserves to energy megawatts and procure additional reserves to meet the next largest contingency.

Zhang said some of the significant changes over the status quo in the proposal include updating the economic basepoints to replace all-call instructions and having active constraints controlled by IRD so that deployed resources don't have negative impacts on the constraints.

PJM is looking to conduct a phased approach of IRD with the initial phase of 6 to 12 months beginning in early 2022, Zhang said, possibly by March. The RTO will reconvene the SRDTF toward the conclusion of the initial phase to review performance metrics, solicit stakeholder feedback and adjust and finalize deployment approach and adapt to market changes.

"IRD is production ready," Zhang said. "It's been designed to be highly flexible and customizable so we can make changes on the fly as needed."

Siva Josyula, Monitoring Analytics | *© RTO Insider LLC*

Siva Josyula of Monitoring Analytics asked what changes could be made "on the fly" by PJM.

Zhang said one of the major changes is the use of the largest contingency, which was a major focus of the effort. Zhang said the development of using the largest contingency was driven by fears of both over- and under-deployment of resources.

Josyula *reviewed* the IMM proposal, saying the concept was to ensure reserves are deployed in proportion to the cause of the spin event. He said the resources deployed during a spin event would be those that clear and are being compensated for providing synchronized reserves.

The proposal called for using a reserve deployment tool that generates new dispatch signals, and the total megawatts to deploy would be equal to those lost or required for area control

PJM News

error recovery.

Stakeholders voted down the IMM proposal, with 159 votes against (76%).

Brock Ondayko of AEP Energy questioned the effectiveness of both the PJM and IMM proposals, saying it wasn't clear what problems they solve. Ondayko said units will be forced into a market system that "doesn't model things correctly" and that will ultimately have ramifications for other market products and systems, opening a "pandora's box" of issues.

"You're trying to fix a problem with solutions that don't address the main issue while you're trying to force people to update things in a system that's not adequate for updating," Ondayko said.

The PJM proposal will go on to the Nov. 17 Markets and Reliability Committee meeting for a first read and a final endorsement vote at the January Members Committee meeting.

Day-ahead Schedule Reserve Endorsed

Members unanimously endorsed changes to the 2022 Day-ahead Scheduling Reserve (DASR) requirement.

David Kimmel, senior engineer in PJM's performance compliance department, *reviewed* the proposed changes to the DASR *requirement*, which is the sum of the requirements for all zones within the RTO and any additional reserves scheduled in response to a weather alert or other conservative operations. (See "Day-ahead Schedule Reserve (DASR)," *PJM Operating Committee Briefs: Oct. 7, 2021*.)

DASR is the sum of the three-year averages of both the under-forecasted load forecast error (LFE) and eDART forced outage rate component.

The final endorsed 2022 DASR requirement was 4.43%, Kimmel said, slightly lower than the 2021 requirement of 4.78%. Kimmel said the number comes from the LFE component of 2.04%, which is down 0.14% from last year, and the forced outage component of 2.39%, down 0.21%.

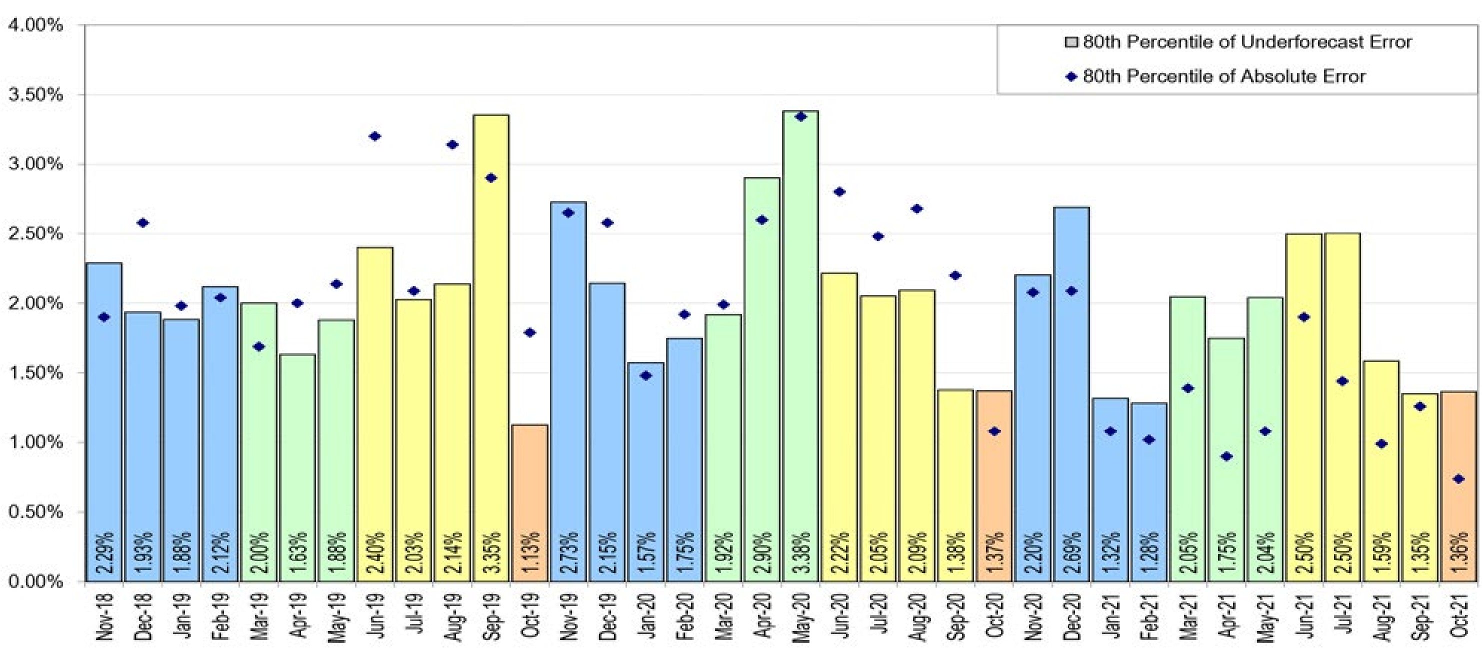
The value is incorporated into Manual 13 changes and effective through Sept. 30, 2022, after which it will be replaced with the day-ahead secondary reserves. Kimmel said the change is dependent on *FERC*'s review and action on reserve price formation and PJM's operating reserve demand curve (ORDC).

Manual Changes Endorsed

Several manual updates were unanimously endorsed. They included:

- Manual 14D — Vince Stefanowicz, senior lead engineer with PJM's generation department, *reviewed* updates to *Manual 14D: Generator Operational Requirements* as a part of the periodic review. The updates featured the addition of several new sections, including one describing eDART modeling requirements.
- Manual 10 — Stefanowicz also *reviewed* updates to *Manual 10: Pre-Scheduling Operations* as a part of the periodic review. The updates resulted from FERC's approval of changes to black start unit testing.
- Manual 3 — Dean Manno of PJM's transmissions operations department *reviewed* updates to *Manual 3: Transmission Operations* as a part of the periodic review. Updates included minor changes such as removing a reference to NERC standard PRC-001 because of its retirement.
- Manual 13 — Brian Oakes of PJM's dispatch department *reviewed* updates to *Manual 13: Emergency Operations* as part of the periodic review. Updates include notes to articulate the expectations of members' load shed plans.

The manual changes will be voted on at the November MRC.



PJM chart of under-forecasts of load forecast error from November 2018 to the present | *PJM*

PJM News

FERC Levies $242M in Fines on GreenHat, Owners

By Michael Yoder

FERC on Friday said it had determined that GreenHat Energy and its owners violated the Federal Power Act by "engaging in a manipulative scheme" in PJM's financial transmission rights market, issuing a total of $242 million in fines for the company's 890 million MWh default in 2018 (*IN18-9*).

The commission assessed civil penalties of $179 million on the company and $25 million each on owners John Bartholomew and Kevin Ziegenhorn. FERC also directed GreenHat, Bartholomew, Ziegenhorn and the estate of Andrew Kittell to disgorge more than $13 million in unjust profits, plus applicable interest.

GreenHat acquired the largest FTR portfolio in PJM between 2015 and 2018 but defaulted on the portfolio in June 2018, leaving PJM stakeholders to cover more than $179 million in the market to the present. When the company defaulted, FERC said, GreenHat had only $559,447 in collateral on deposit with PJM. (See *Doubling Down — with Other People's Money*.)

"Respondents, over several years, deliberately carried out one of the largest frauds in the history of organized energy markets, leading to the largest default in the history of those markets, resulting in losses of more than $179 million," FERC said in its ruling. "Staff notes that Bartholomew and Ziegenhorn showed no commitment to compliance, did not self-report their violations and provided limited cooperation."

FERC Findings

The commission found that GreenHat and its owners violated the FPA in four different ways, calling it a "classic fraud," similar to a "bust-out" scheme involving selling assets that one does not intend to pay for. The violations cited by the commission included:

- engaging in a manipulative scheme in PJM's FTR market to acquire a portfolio made up of primarily long-term FTRs with "virtually no supporting, upfront capital, planning not to pay for losses at settlement" and selling profitable FTRs to third parties at a discount to obtain cash for the owners;
- buying FTRs not based on market considerations but to accumulate as many FTRs as possible "with minimal collateral, thereby engaging in a course of conduct for the purpose of impairing, obstructing or defeating a well functioning market";
- making false statements to PJM concerning money supposedly owed by Shell Energy North America with the intent to convince the RTO not to proceed with a planned margin call; and
- submitting inflated bids into the PJM long-term FTR auction to "artificially raise the clearing price" of FTRs that Shell had purchased from GreenHat and offered for sale in the auction.

FERC said the Office of Enforcement found documents showing GreenHat's "continued reliance" on the PJM Credit Calculator, instead of "traditional market fundamentals," to purchase FTRs "despite multiple indications that such strategy was resulting in an increasingly negative portfolio for the firm." The office said the owners failed to provide any "reasonable economic rationale" for using the calculator.

The commission said staff also discovered emails during the investigation "demonstrating that GreenHat sought to sell its profitable FTRs to third parties using other valuation methodologies" rather than the calculator, while "continuing to grow its negative portfolio using the PJM Credit Calculator."

"Respondents intentionally misled PJM to enable GreenHat to buy FTRs that it otherwise would not have been able to afford to buy and extract profits from the PJM FTR market with the intent to default on their portfolio losses," FERC said.

Kittell Estate

The decision is slightly complicated by an ongoing investigation by the Department of Energy's Office of the Inspector General (OIG) into an email exchange between FERC Enforcement's Division of Investigations (DOI) lawyers Thomas Olson and Steven Tabackman regarding the GreenHat case. FERC *released* the emails in October after Olson, who is part of the litigation staff in the GreenHat proceeding, disclosed them to Enforcement management.

The estate of Kittell, who killed himself by jumping off the San Diego-Coronado Bridge in California on Jan. 6, made a filing for FERC to drop its enforcement action and investigate the two employees. (See *Estate of GreenHat's Kittell Lobbies FERC to End Enforcement Action*.)

The commission said the email exchange between Olson and Tabackman "addressed procedural matters that might arise under California probate law" in a proceeding addressing the Kittell estate, but it was not a conversation about the "issue currently before the commission in this proceeding."

FERC said with the OIG investigating the matter, it was not ruling on the Kittell estate motion "at this time" and will instead "address the merits of the motion" in a separate order once the OIG rules on the case.

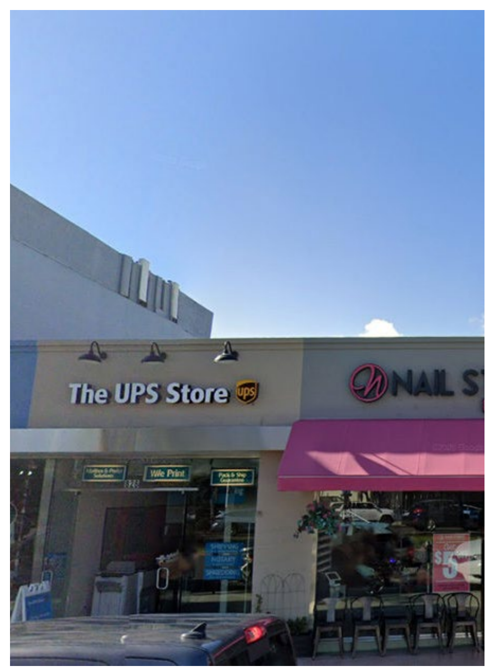
Danly Dissent

Danly dissented from the views of the commission, saying, "Enforcement failed to provide the proof necessary to meet its burden."

Having reviewed GreenHat's answer and Enforcement's reply, Danly said he remained "deeply skeptical" of GreenHat's explanations, but he said his skepticism is "irrelevant." He said it was not necessary for GreenHat to prove its innocence, but it was for Enforcement to "prove its case to a preponderance of the evidence."

Danly had harsh words for PJM, saying the RTO was partially to blame for the result of the default.

"While not the subject of the instant proceeding, we would do well to keep in mind the share of the blame that must rightly be assigned to PJM," Danly said. ■



GreenHat listed its address as 826 Orange Avenue, Suite 565, Coronado, Calif. — a UPS store between a nail salon and a RiteAid. | *Google*

SPP News

Southern Star Gas Pipeline Joins SPP

Southern Star Gas Pipeline has become the first gas transportation company to join SPP as a member. | *Southern Star*

SPP on Nov. 1 added Southern Star Central Gas Pipeline as its first pipeline company member in what the RTO says is part of its effort to "strategically align" with fuel resources and improve the coordination between the electric and gas industries.

The RTO said it has had an "effective working" relationship with Southern Star for nearly 10 years, as evidenced by the collaboration between the two during the February winter storm to address fuel supply issues in their shared footprint.

SPP's comprehensive review of the winter weather event identified gas supply issues as one of the primary reasons for forced generation outages that ultimately led to the grid operator's first load sheds in its 80-year history. The report included three recommendations related to improving gas-electric coordination. (See *SPP, Members Begin Response to February's Winter Storm*.)

"Southern Star has a similar corporate culture to SPP and is very customer-focused," C.J. Brown, SPP's director of systems operations, said in a *statement*. "We have helped educate both organizations' staff about our respective business, and that has been extremely helpful as we experienced operational issues."

Southern Star CEO Jimmy Staton said, "We look forward to building strategic initiatives to improve gas-electric harmonization across the country benefiting all stakeholders while finding efficiencies as energy providers."

The Kentucky-based company will be included in SPP's large-retail customer segment, increasing the grid operator's membership total to 107. It owns 5,800 miles of pipelines in Kansas, Oklahoma, Missouri, Wyoming, Colorado, Texas and Nebraska. ■

— Tom Kleckner

SPP News

FERC Accepts Tri-State's Exit Fee Calculation

Commission also Sets Hearing Procedures, Opens 206 Inquiry

By Tom Kleckner

Tri-State Generation and Transmission may finally have in place exit procedures for members leaving the cooperative, but regulatory roadblocks remain for the contract termination payment (CTP) methodology.

FERC issued an order Oct. 29 accepting the co-op's proposed methodology effective Nov. 1, subject to refund, and rejecting nearly a dozen protests from members. However, the commission said its preliminary analysis indicates that the methodology has not been shown to be just and reasonable and established hearing procedures to address issues not in the record (*ER21-2818*).

The commission also opened a Federal Power Act Section 206 proceeding so it can establish a just and reasonable CTP-calculation methodology and just-and-reasonable procedures for Tri-State's utility members to obtain the CTPs and withdraw in an orderly manner. It encouraged the hearing's presiding judge to expedite the hearing where feasible "to facilitate the … resolution of these longstanding disputes."

Tri-State's first CTP methodology filing was submitted in April 2020. FERC accepted it subject to refund but also established hearing and settlement judge procedures. The process was repeated several times as the co-op filed policies and other calculation methods in response to member protests.

In May, FERC rejected the CTP methodology without prejudice, leading to Tri-State's latest filing in September. Many of the complaints centered on members being able to see the calculations. (See *FERC Rejects Tri-State Exit Fee Proposal*.)

FERC said Tri-State's newly proposed procedures allowing members' access to the modified CTP methodology "appear to satisfy a number of the commission's concerns." The co-op proposed providing CTP calculations annually to all utility members at no charge by April 1, whether or not the member intended to withdraw from Tri-State.

Tri-State says it is doubling its renewable capacity. | *Tri-State Generation and Transmission*

Members seeking to terminate their wholesale electric service contracts (WESCs) and co-op membership must provide a two-year advance notice of their intention and pay its CTP to Tri-State on the withdrawal date.

"These procedures are clear and transparent," the commission wrote.

FERC, however, disagreed with Tri-State's claims that a CTP methodology must be based on a lost-revenues approach to be just and reasonable. It also said it shared protesters' concerns that additional mitigation efforts could be used to decrease revenues that the co-op would otherwise be losing upon a member's exit.

Tri-State CEO Duane Highley | *SPP*

"While we disagree with some of the positions being taken by select parties, we appreciate FERC providing the opportunity for broader participation by all interested members in the case," Tri-State CEO Duane Highley said in a *statement* last week. "We welcome the continued engagement of our membership, and we will continue to work to ensure that all members, large or small, have a voice that is heard on these important matters."

The co-op said the modified CTP tariff ensures remaining members are held harmless if another member decides to terminate its contract early and includes "clear, transparent and objective procedures."

"At the same time, we are mindful of the questions and concerns expressed by the commission … and will do our best to address them through the hearing process," Tri-State said.

Tri-State has 45 members, including 42 utility distribution cooperatives and public power district members in four states that supply power to more than 1 million electricity consumers across nearly 200,000 square miles of the West. ■

Company Briefs

Exelon Considering Hydrogen Production at Nine Mile Point

Exelon on Wednesday announced that it has received a grant from the U.S. Department of Energy to explore hydrogen production at its Nine Mile Point nuclear plant in New York.

"Hydrogen will be key in helping the nation address the climate crisis, and nuclear plants can play a vital role in this production," CEO Christopher Crane said during the company's third-quarter earnings call.

The company reported about $1.27 billion ($1.23/share) in net income for the quarter, a 140% jump over the same period in 2020. Adjusting for the mark-to-market impact of economic hedging activities, however, Exelon made about $1.07 billion ($1.09/share). Though higher than last year's $1.04/share, that still missed analyst expectations of $1.10.

The increase in earnings was primarily from higher rates at its regulated utilities, including Commonwealth Edison, PEPCO and Baltimore Gas & Electric.

More: *Exelon*

PPL Q3 Adjusted Earnings up

PPL on Thursday reported third-quarter net income of $207 million ($0.27/share), compared with $281 million ($0.37/share) last year. Adjusted for a $70 million charge related to the early extinguishment of debt, the company said earnings were up about 21% to $277 million.

The company is in a period of transition, as it recently sold its utility business in the U.K. and used some of the proceeds to purchase Narragansett Electric in Rhode Island. It expects to complete the latter transaction by March 2022 pending approval by the state's Division of Public Utilities and Carriers.

During a conference call with analysts, company officials said it plans to invest up to $1 billion over the next five years in its regulated utilities to "support grid modernization" and resilience.

More: *PPL*

EBA Honors Doot with Paul E. Nordstrom Service Award

The Energy Bar Association (EBA) last month honored David Doot with the 2021 Paul E. Nordstrom Service Award. The award recognizes exemplary long-term public service to the community through the EBA, the Charitable Foundation of the Energy Bar Association (CFEBA) or the Foundation of the Energy Law Journal (FELJ).

Doot, a partner and former chair of Day Pitney's Energy and Utilities industry group, is a former president of the EBA and has served in many leadership positions during his more than 30 years as an association member, including the EBA's board of directors, the CFEBA and the FELJ.

More: *EBA*

WEC Energy Group to Eliminate Coal Use by 2035

WEC Energy Group last week said it has set a goal of eliminating coal as a fuel source by 2035.

The company said it expects coal to provide less than 5% of its power supply by 2030. In a capital spending plan it shared with investors, WEC said it intends to invest $5.4 billion in renewable energy between 2022 and 2026.

WEC Energy reported net income of $290 million ($0.92/share) for the third quarter, up from $266.8 million ($0.84/share) reported in last year's third quarter.

More: *Milwaukee Journal Sentinel*

Xcel Unveils Goal of Carbon-neutral Natural Gas by 2050

Xcel Energy last week said it is aiming for "net-zero" carbon emissions from its natural gas system by 2050.

Xcel, Minnesota's second-largest gas utility and largest electricity provider, joined a handful of other gas utilities by announcing plans to extricate carbon in Minnesota and other states by replacing some gas with hydrogen. The utility's plan starts with measures that can be taken soon, including improving efforts to detect and stop leaks on its distribution system and purchasing gas from suppliers with "certified low emissions."

The company also plans to launch pilot programs to test both "green" hydrogen and renewable natural gas in its delivery system and has plans for five to eight hydrogen projects.

More: *Star Tribune*

Federal Briefs

DOE Aims to Slash Cost of Removing Carbon from Air

At the U.N. climate summit last week, Secretary of Energy Jennifer Granholm said the agency would invest in carbon removal research with the goal of pushing the cost under $100 per ton by 2030. That's far below the price tag for many current technologies, which can cost as much as $2,000 per ton.

The goal is to identify techniques that can remove billions of tons of carbon dioxide from the atmosphere and permanently store it.

The U.N.'s Intergovernmental Panel on Climate Change estimates that the world may need to remove 100 billion to one trillion tons of emissions this century to stay below 1.5 degrees Celsius of warming.

More: *The New York Times*

House Dems Subpoena Oil Companies over Climate Disinformation

The House of Representatives Committee on Oversight and Reform issued subpoenas last week for documents from ExxonMobil, Chevron, BP and Dutch Royal Shell concerning what Democratic lawmakers describe as a concerted effort by the industry to sow doubt about the scientific reality of global warming.

Two lobbying groups funded by fossil fuel firms, the American Petroleum Institute and U.S. Chamber of Commerce, were also given subpoenas.

Rep. Carolyn B. Maloney (D-N.Y.) said the entities failed to produce a "substantial portion" of the documents requested ahead of a hearing two weeks ago, at which top executives appeared before the House panel for questioning about climate change. In September, the panel asked the companies to voluntarily hand over documents related to their marketing and lobbying efforts and their funding of outside groups.

More: *The Washington Post*

Report: Global CO_2 Emissions to Rebound to Pre-pandemic High

Data compiled by the Global Carbon Project and published last week in Earth System Science Data suggests carbon dioxide emissions are expected to jump by 5% this year to roughly where they were in 2019 before the COVID-19 pandemic brought the global economy to a halt.

Emissions from coal are also expected to surge and surpass 2019 levels. Coal use had been declining since a peak in 2014, but the data suggests that trend may have stalled. Oil is the only fossil fuel for which emissions have yet to return to 2019 levels, largely because air and road travel remain lower.

More: *Inside Climate News*

State Briefs

ARIZONA

Corporation Commission Adopts New Shutoff Rules

New service termination rules adopted by the Corporation Commission will require utilities to follow one of two allowed shutoff guidelines:

1. when temperatures are forecasted to top 95 degrees or drop below 32 degrees or when the commission issues an order finding weather conditions are dangerous;
2. during a period from June 1 through Oct. 15 annually.

Tucson Electric Power and Arizona Public Service will adopt the June-October shutoff moratorium and continue to suspend shutoffs in temperatures of 32 degrees and below.

The new rules are expected to become effective around March, following a review by the attorney general and filing with the secretary of state.

More: *Arizona Daily Star*

Corporation Commission Cuts $119M from APS Revenue

The Corporation Commission last week approved a $119 million cut from Arizona Public Service's revenue after reviewing data that confirmed most customers would see their monthly bills reduced. APS said it will sue over the decision.

The commission decided major elements of the two-year rate case during meetings in October, deciding to slash the company's profitability and cut hundreds of millions from APS' request to charge customers for upgrades at a New Mexico coal plant. After the changes, APS will see a slight increase in revenue, largely because of adjustors that charge customers for specific items such as power plant fuel and renewable energy programs. Its "base rates" are declining by $119 million.

APS said about 69% of customers would see a bill reduction of 2% or less. About 21% will see an increase of less than 1%, while 7% are projected to see increases from 1-3%.

More: *Arizona Republic*

KENTUCKY

Solar Farm Granted Construction Certificate

The State Board on Electric Generation and Transmission Siting last week conditionally granted a construction certificate to McCracken County Solar for its proposed 60-MW solar farm.

The certificate is good, provided the company complies with 36 mitigation measures and conditions outlined in an Oct. 30 ruling.

The company still needs approval of its conditional use permit application by the county's Board of Adjustment. At a special meeting, the board stayed its previous vote to deny the permit with plans to reopen the public hearing on the matter Nov. 17.

More: *The Paducah Sun*

MICHIGAN

DTE Plans Investment in Grid, Tree Trimming

DTE Energy last week said it plans to invest $7 billion during the next five years to modernize southeast Michigan's grid and prepare for increasing demand from electric vehicles. The funds will help update and build new substations and add 700 MW of capacity.

The company is tripling its investment in tree trimming, which can increase reliability by as much as 70%. The Public Service Commission approved DTE's request to spend an additional $70 million on tree trimming through 2023 following power outages this summer from severe storms.

More: *The Detroit News*

MINNESOTA

Minnesota Power Requesting Rate Increase

Minnesota Power last week filed a request with the Public Utilities Commission to increase its annual operating revenue by $108 million.

The request would increase customers' monthly bills by 18% ($15). However, since the commission takes up to a year to approve a request, the company asked for an interim rate increase of 14% ($12). That rate would take effect in January and remain until a decision is made on the final rate.

The increase stems from investments Minnesota Power has made in its "EnergyForward" clean energy transition since 2016.

More: *Fox 21*

NEW MEXICO

Hearing Examiner Recommends Rejection of PNM-Avangrid Merger

Hearing examiner Ashley Schannauer, who serves as a quasi-judge for the New Mexico Public Regulation Commission, last week released a 445-page report that recommended against the merger of the Public Service Company of New Mexico and Avangrid.

Schannauer said his review of the proposal found the potential harms of the deal outweigh the benefits. He said there have been so many amendments to the proposed agreement that "there is no longer an agreement that can be approved." However, Schannauer said if the commission is inclined to approve the merger, he would recommend various modifications to a June 4 agreement the companies reached with numerous organizations that have an interest in the proceedings.

Schannauer only has the power to make recommendations to the PRC. If the commission agrees with him, PNM and its partners can appeal the decision to the New Mexico Supreme Court.

More: *Santa Fe New Mexican*

NEW YORK

Ithaca to Decarbonize Buildings

The Ithaca Common Council last week voted unanimously to electrify and decarbonize all of the city buildings. It is the first such initiative of its kind in the country.

The city of about 30,000 people consists of some 6,000 homes and buildings, which if electrified, would remove about 40% from the city's overall carbon footprint.

The move is part of a broader Green New Deal that the city approved in 2019, which calls for the city government to meet its electricity needs with renewable energy by 2025.

More: *The Washington Post*

OHIO

Issue 7, Mysterious Clean Energy 'Scam,' Fails

Voters last week rejected Issue 7, a ballot measure that would have put nearly 10% of Columbus' annual budget toward vague clean energy initiatives, by voting it down by a more than 6-to-1 margin (86.8%).

Issue 7 would have set aside $87 million of the city's general fund to "promote and fund" programs for "clean energy education and training," "energy conservation and energy efficiency initiatives," and others. However, Mayor Andrew Ginther called Issue 7 "one of the biggest scams in the city's history" because it would have set up four funds but given the city no control over the money.

Last week, NBC4 tried to track down the measure's six petitioners, but their listed addresses led to a home, which had been sold.

More: *WCMH*

TEXAS

Austin to Keep Running Fayette Coal Plant, Miss Climate Goal

Austin Energy last week announced it will not retire its stake in the Fayette coal-fired plant next year after failing to reach a closure agreement with co-owner Lower Colorado River Authority.

Closing the portion of the plant by 2022 was an important step to achieving carbon-reduction goals outlined in Austin Energy's Resource, Generation and Climate Protection Plan to 2030. The plan was also a cornerstone of the city's ambitious Climate Equity Plan, which aims to reach "net zero" emissions by 2040.

Five years ago, Austin's share of the plant was found to be responsible for "80% of the utility's greenhouse gas emissions and 28% of all Austin's greenhouse gas emissions," said council's Joint Sustainability Committee.

More: *KUT*

Broad Reach Power Brings 2 Battery Storage Plants Online

Independent power producer Broad Reach Power last week brought two 100-MW battery storage systems online that will participate in the ERCOT market.

Broad Reach Power, founded in 2019, first announced the two projects totaling $100 million in September 2020.

More: *Energy Storage News*

WISCONSIN

PSC Approves Natural Gas Storage Projects

The Public Service Commission last week approved plans for We Energies and Wisconsin Gas' $370 million natural gas storage project.

The companies say the dual facilities in Jefferson and Walworth counties are needed to improve reliability and resilience and estimate the cost will be at least $224 million less than other alternatives. The facilities, which would hold a billion cubic feet of gas, will chill natural gas to minus-260 degrees for times of high demand, when it will be heated and vaporized.

More: *Wisconsin State Journal*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