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COVER: House Speaker Kevin McCarthy (R-Calif.) answers questions about the debt ceiling deal at a Sunday press conference, with Rep. Patrick McHenry (R-N.C.) at his right. | *Speaker Kevin McCarthy*

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Debt Ceiling Bill Provides 'Mini-deal' on Permitting

Timelines for NEPA Reviews Limited, but 6-Year Window for Legal Challenges Remains

By K Kaufmann

The debt ceiling compromise hammered out between President Joe Biden and House Speaker Kevin McCarthy (R-Calif.) would cut the time allowed for reviews under the National Environmental Policy Act (NEPA) to two years for a full environmental impact study and one year for a less intensive environmental assessment.

The main text of the *Fiscal Responsibility Act* (FRA), released Sunday, would raise the debt limit through Jan. 1, 2025; claw back some federal funding, such as billions in unused COVID-19 funding; and cap federal spending at current levels through 2024.

But 27 pages of the 99-page bill are focused on streamlining and accelerating permitting, including the designation of a single lead federal agency for such reviews and an expansion of the use of "categorical exclusions," or waivers that would exempt projects from NEPA evaluations.

Speaking at press conference on Sunday, McCarthy called these changes "transformational."

NEPA "hasn't been reformed in 40 years," McCarthy said. "It's a frustration with people all across this country, on both sides of the aisle. [It] doesn't matter if you want to build a road [or] you want to build a renewable energy project. That all gets stopped and studied for years. It's a frustration. That's millions of dollars wasted. That is all changing now so we can build again in America. We can make America strong. We [can] compete with other countries."

Rep. Garret Graves (R-La.), one of the chief GOP negotiators, described the bill's NEPA provisions as "shrinking the scope" of federal environmental reviews.

"NEPA has grown to just study all these things that don't have anything to do with the environment, which I would argue … has worked against the protection of the environment," Graves said during the Sunday press conference. "So, we're trying to refocus the scope back on that, on the environmental impacts, and making sure we get the best environmental outcomes."

But the White House framed the permitting provisions as a win for the key climate provisions of the Inflation Reduction Act, which the Republicans' original debt ceiling package, the Limit, Save, Grow Act (*H.R. 2811*), had sought to roll back.

House Speaker Kevin McCarthy (R-Calif.) answers questions about the debt ceiling deal at a Sunday press conference, with Rep. Patrick McHenry (R-N.C.) at his right. | *Speaker Kevin McCarthy*

"We secured measures that will harness government efficiencies to accelerate construction projects across the country," a White House official said during a *background press call* Sunday. "Specifically, the agreement includes measures aimed at boosting the coordination, predictability and certainty associated with federal agency decision-making. …

"And the agreement, importantly, makes these changes without curtailing the substantive scope of the NEPA statute," the official said. "It doesn't cut down the statute of limitations, as was proposed in [the GOP bill], or impose barriers to standing, or taking away injunctive relief or other judicial remedies."

Republican proposals for changes to NEPA could have cut the window for judicial challenges from six years to as little as 60 days.

Both Biden and McCarthy emphasized that the bill is the result of negotiations in which neither side got everything they wanted. McCarthy also stressed that once the text of the bill was released, the House of Representatives would not vote on it for 72 hours to give lawmakers and the public time to review it.

Amid grumblings on both sides that concessions in the bill are too deep, questions remain on whether Republican and Democratic leaders in the House and Senate will be able to rally the votes they will need to pass it. Biden urged Democrats to pass it, and McCarthy expressed confidence that Republicans would fall in line and vote for the bill.

NEPA Reviews

With Graves as a key GOP negotiator, the FRA's permitting provisions incorporate many but not all the provisions from his *Building U.S. Infrastructure through Limited Delays & Efficient Reviews Act*, originally introduced in 2021.

In addition to the time limits on environmental reviews, the FRA would set a limit of 150 pages for EISes and 300 pages for projects of "extraordinary complexity … not including any citations or appendices." EAs would be similarly limited to 75 pages, plus citations and appendices.

It would also require the designation of a

FERC/Federal News

lead federal agency to coordinate and set a schedule for any environmental review. And state, local or tribal agencies could be enlisted as co-lead or cooperating agencies.

If a lead agency did not produce an environmental review within mandated deadlines, the bill would allow a deadline extension, "in consultation with the applicant … that provides only so much additional time as is necessary to complete such environmental impact statement or environmental assessment."

The bill specifies that the scope of such reviews should focus on "reasonably foreseeable environmental effects of the proposed agency action [or] any reasonably foreseeable adverse environmental effects which cannot be avoided should the proposal be implemented." A "reasonable range of alternatives" would have to be examined, including negative environmental impacts arising from not completing the project.

It would also expand the use of categorical exclusions by allowing one federal agency to use the categorial exclusion that another agency has issued for a specific project. It would allow the use of "programmatic environmental" reviews, which cover a specific region or corridor in which one or more projects are located. The programmatic review can be used in the permitting of individual projects in the area covered by the review for up to five years or longer, "unless there are substantial new circumstances or information about the significance of adverse effects that bear on the analysis."

The bill does not define what "reasonably foreseeable" environmental impacts are, and as noted by White House officials, it would not cut back the current six-year time frame for legal challenges to a NEPA environmental review.

More Changes in Offing?

In a major win for Sen. Joe Manchin (D-W. Va.), the bill calls for expedited completion of the embattled Mountain Valley natural gas pipeline (MVP), a provision also included in his permitting bill, the Building American Energy Security Act.

The FRA would declare the 303-mile project "in the national interest" and order the secretary of the Army to complete any final permitting on the pipeline within 21 days of the enactment of the law.

It would also prohibit any further litigation on the project, save for challenges to this provision itself, which could only be heard by the D.C. Circuit Court of Appeals.

This limit raises a question on whether passage of the FRA would retroactively nullify Friday's decision from the D.C. Circuit overturning FERC's decision to not perform a new EA of the pipeline. The decision requires FERC to perform the study but does not stop construction on the pipeline, which is 94% complete. (See related story, *DC Circuit Partly Vacates FERC Gas Pipeline Approval*.)

In a statement released Sunday, Manchin claimed credit for securing the Mountain Valley provisions. "I am pleased Speaker McCarthy and his leadership team see the tremendous value in completing the MVP to increase domestic energy production and drive down costs across America and especially in West Virginia," he said. "I am proud to have fought for this critical project and to have secured the bipartisan support necessary to get it across the finish line."

For transmission advocates, the FRA would authorize an "Interregional Transfer Capability Determination Study." It would task NERC with completing this study in 18 months, looking at current transfer capabilities between "neighboring transmission planning regions" and making recommendations for "prudent additions to transfer capability" to improve reliability. The completed study would be submitted to FERC, which would have another year, plus a public comment period, to finalize and submit the report to Congress.

Rob Gramlich, president of Grid Strategies, an industry consulting firm, said the FRA contained little of significance to accelerate the permitting and construction of interregional transmission. The study could "raise a lot of people's awareness about the benefits of transmission connecting regional grids," Gramlich said. "But there's still some debate about the details, like why does it take 2.5 years" for NERC and FERC to complete the report.

He also noted that FERC is already studying interregional transfers and recently ended a comment period following a technical conference on the subject. In general, stakeholders support the concept of expanding interregional transfer capability on the grid but differ on how to get there. (See *Minimum Transfer Capability Between Regions Debated at FERC*.)

The FRA would authorize another study to explore "the potential for online and digital technologies to address delays in reviews and improve public access." Such an "e-NEPA" portal would allow developers to submit and track the progress of permitting applications online and allow federal agencies to collaborate and edit documents in real time. The bill would appropriate $500,000 for the study, which the White House's Council on Environmental Quality would conduct and submit to Congress in a year.

The bill's inclusion of energy storage projects in the *FAST-41* process provides another small win for clean energy advocates. Originally set up under the Fixing America's Surface Transportation Act in 2015 and expanded by the Infrastructure Investment and Jobs Act, FAST-41 allows for expedited permitting of certain infrastructure projects and already has an *online dashboard* for tracking projects. The White House official said that while some of the FRA's provisions streamlining permitting do overlap with FAST-41, the processes are different.

Industry consultants ClearView Energy Partners characterized the FRA's permitting provisions as a "mini-deal" that will "not make the holistic changes Republicans laid out in multiple recent proposals or transmission reforms sought by Democrats."

The question now is whether the modest nature of the provisions will "mean more reforms [are] in the offing."

"A reopening of debate looks more likely than actual finalization, but we expect lawmakers to try," ClearView said. Prior to the deal, the Senate committees on Energy and Natural Resources and on Environment and Public Works had each committed to working on bipartisan permitting bills.

However, ClearView said, "the FRA mini-deal is more likely to undercut momentum for such efforts than to stoke it." ■

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FERC/Federal News

Report: Storage Projects Stymied at Distribution System Interconnection

Cost Allocation, Lack of Planning and Utilities' Misassumptions Delay and Discourage Developers

By K Kaufmann

All the Albuquerque Public Schools (APS) system wanted to do was put some solar panels and storage at its largest high school, which has a huge campus and, at times, five-figure electricity bills. And APS had federal and state grants to help pay for the project.

But, according to Tony Sparks, APS's HVAC and energy projects manager, the 850-kW solar system and accompanying battery storage have now been sitting at the school for close to a year, unable to connect to the distribution system, while school officials have struggled through a Kafkaesque interconnection process.

Beginning in September 2021, a yearlong initial review by APS's local utility required biweekly meetings with the utility's interconnection team and was followed by a series of requests for supplemental reviews, Sparks said Wednesday during a webinar on the bottlenecks that storage projects face at the distribution level.

"I didn't know there were so many supplemental reviews available — technical and grid risk and modification," he said. "They had a lot of names for them, but each time they would start a new one, they'd say, 'OK, it's going to take at least another 30 or 60 business days for this particular one.' … And I have to say, we felt like we were getting a bit of a runaround."

A meeting of all stakeholders last month finally resulted in a conditional approval, providing APS made specific upgrades to the distribution system, which, Sparks reported, have been delayed at least 20 weeks because of supply chain and labor issues. Beyond the extra expenses of the interconnection process and upgrades, the school system has lost a "couple hundred thousand dollars" in savings the solar and storage were expected to provide, he said.

"The challenges of this project on the interconnection side [could] greatly discourage development of this kind of project," Sparks said. "If we didn't have so much tenacity and enthusiasm, and so many people involved … I don't think we would have remained in there."

While overloaded queues for transmission interconnection have become a major focus for the electricity industry, regulators and policy makers, a new *report* from the Applied Economics Clinic and the Clean Energy Group shows that experiences like Albuquerque's may also be the norm on local distribution networks across the country. In Massachusetts, for example, the report found more than 1,600 storage or solar and storage projects had either incomplete or withdrawn interconnection applications in 2022, versus fewer than 400 complete or approved.

The 850-kW solar system, with storage, has been been complete but unable to interconnect to the local distribution system since August of 2022 because of a range of interconnection bottlenecks and supply chain and workforce delays. | *Alburquerque Public Schools*

The webinar, sponsored by the Clean Energy Group, dug into the reasons for such lopsided figures and explored potential solutions. Bottlenecks and other barriers are embedded in the interconnection process itself, said Chirag Lala, a researcher at Applied Economics, who worked on the report.

Key factors are a lack of system planning, the underlying, often mistaken assumptions many utilities make about storage, along with "cost causation," that is, how the costs of system upgrades are allocated, Lala said.

The need for distribution upgrades is determined based on the "hosting capacity" of specific lines in a system — how much renewable generation or storage they can integrate — on a case-by-case basis as interconnection applications are filed. "It creates a system where nobody is planning ahead of time for distribution-level hosting capacity upgrades," he said.

"There is not [a state-level] entity … that is able to say, 'We anticipate this much distributed energy resources will interconnect. We want to prepare for this much solar, this much storage, this much hybrid [solar and storage], and we should make these upgrades in advance,' Lala said.

In addition, as developers are usually responsible for paying for system upgrades, "it means those who are responsible for managing the distribution grid don't have a financial incentive to actually invest in hosting capacity more regularly," he said.

Potential solutions include the use of online maps some utilities — such as Con Edison and Green Mountain Power — are now providing for solar and storage developers to show where lines have adequate capacity for additional projects, and where they are already constrained.

Green Mountain Power's hosting capacity map allows users to drill down to the substation and

FERC/Federal News

line level so developers can be sure a potential site includes the three-phase lines needed for solar and storage projects, said Kirk Shields, the utility's director of development and risk management.

"It really helped the developers figure out where the best sites are going to be so that downstream, we run into fewer traps about upgrades or just not making [a project] feasible at all," Shields said. "It's not a cure-all for every problem, but it certainly has helped smooth out the upfront communication portion of the whole interconnection and build process."

'Worst-case' Studies

Just how much storage is sitting in distribution-level interconnection queues is unknown, but the latest *report* on transmission queues from the Lawrence Berkeley National Laboratory found close to 700 GW of storage now waiting to connect to the bulk power grid.

Getting storage online at the distribution level can have multiple benefits for customers and utilities. For school systems like Albuquerque's, a storage system linked to solar can charge up during off-peak hours, when power is cheap, and discharge during peak times, when power is expensive, which in turn can help trim demand charges.

The city's Atrisco Heritage Academy High School, where the still-unconnected solar and storage are located, is a 65-acre, multibuilding campus. Summertime electric bills are often in excess of $50,000 per month, more than half of which are demand charges, Sparks said.

For utilities, storage can be used as flexible, peaking power that can defer or even replace the need for system upgrades.

But, Lala said, many utilities are still unfamiliar with how storage operates at the distribution level, which can result in unrealistic studies on interconnection and requests for potentially unnecessary and expensive system upgrades.

"A lot of interconnection processes … don't define storage very well, or they insist on treating storage in the modeling as operating at the most extreme use cases," he said. A utility "might say, 'We want to model storage as if it will charge at peak times when everybody else is coming home and using electricity,' even if the project applicants say, 'We never would intend to charge storage around [those] times. We would want to discharge around them.'

"The interconnection processes just generally don't account for either the technologies or logistical processes that might help in preventing that," Lala said.

Schuyler Matteson, a senior adviser with the New York State Energy Research and Development Authority, described the tangled process storage developers face in his state, even with utility hosting capacity maps.

"The utilities still like to look at worst case scenarios because technically many of these projects are still uncontrolled; they're not dispatchable in terms of utility ownership and operation," Matteson said. "They are still doing two studies — one worst-case scenario [for] charging, one worst case scenario [for] discharging."

Further, while many New York utilities have tariffs and demand charges intended to send signals to encourage off-peak charging, Matteson said, "a lot of these interconnection studies are coming back with charging restrictions and discharging restrictions that don't align with the same utility's tariffs."

For example, he said, an interconnection agreement could limit storage developers to charging during peak rather than off-peak hours, resulting in high demand charges. "So, there's this conflict between real-time operational data that the utility has about usage on their system versus historical rates, and when they don't align, you end up having this really high cost burden borne by the developers," he said.

New York also has a "buy-back" demand charge that storage developers must pay for the power they discharge onto the grid during peak times when the power is needed, Matteson said. While the charge is a "historical anomaly" that could soon change — a new rate proposal is before the New York Public Service Commission — it can still be "as expensive as the value we're paying [developers] for the peak power, which makes absolutely no sense at all," Matteson said.

Flexible Interconnection

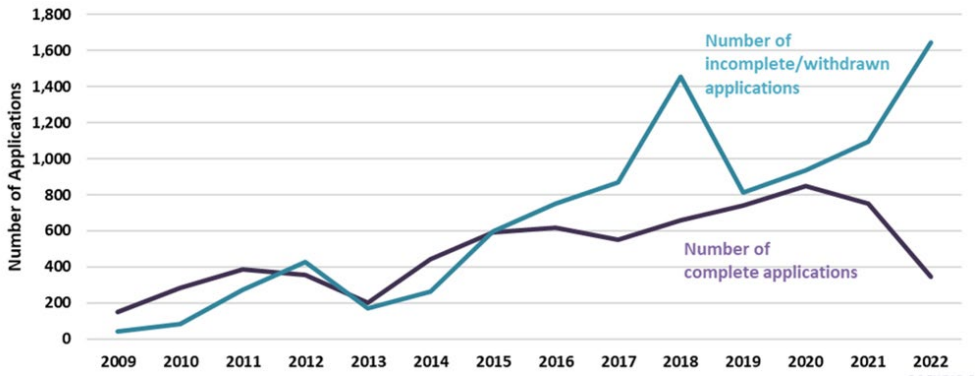
Cost causation is still another pitfall, as upgrades are generally paid for by the developer whose project is seen as tripping the need for system improvements or expansion, even if other projects will benefit, Lala said.

"It also creates an incentive then to jockey in the queue, or at least negotiate quite a bit over what those upgrades will be," he said. "If you are in the queue, it actually matters whether you are first, second, third, fourth or fifth … because if somebody in front of you happens to make upgrades that are useful to your project, you will never be responsible for paying."

This allocation of costs can also create incentives for utilities "to be extra, extra cautious in terms of the system impact modeling that they do in order to determine hosting capacity upgrades," Lala said. "If they're extra cautious and demand more upgrades, that will also raise interconnection costs."

The Advanced Economics report recommends "reforming cost allocation so that you incorporate more stakeholders than just the project … applying for interconnection," he said. Developers applying for interconnection in a cluster can help spread costs, providing they can agree on the individual allocations. If not, and "somebody leaves the group partway through the interconnection process, which can and does happen, then you may have to start the interconnection process all over again" Lala said.

Another possibility is that "a single entity can pay for interconnection-related grid upgrades up-front and be reimbursed by other stakeholders post-upgrade," the report says. For example, a utility could "pay for grid upgrades for smaller-sized projects in the interconnection queue and be reimbursed by customers with larger projects using a one-time pro-rated



Interconnection bottlenecks in Massachusetts last year resulted in more than 1,600 incomplete or withdrawn interconnection applications for solar and storage projects versus less than 400 complete or approved applications. | *Applied Economics Clinic*

FERC/Federal News

fee," he said.

Advanced system planning and pushing for utilities to treat storage "as much as possible based on how [it] will actually operate or function in practice" will also be needed, as well as advanced technologies such "smart inverters" that can help regulate when a storage project charges and discharges.

"Rather than assuming a DER system will export its full nameplate rating, the export capacity (which is equivalent to the nameplate rating or a lower amount when using an acceptable means of control) should be considered and evaluated for its impacts," the report says.

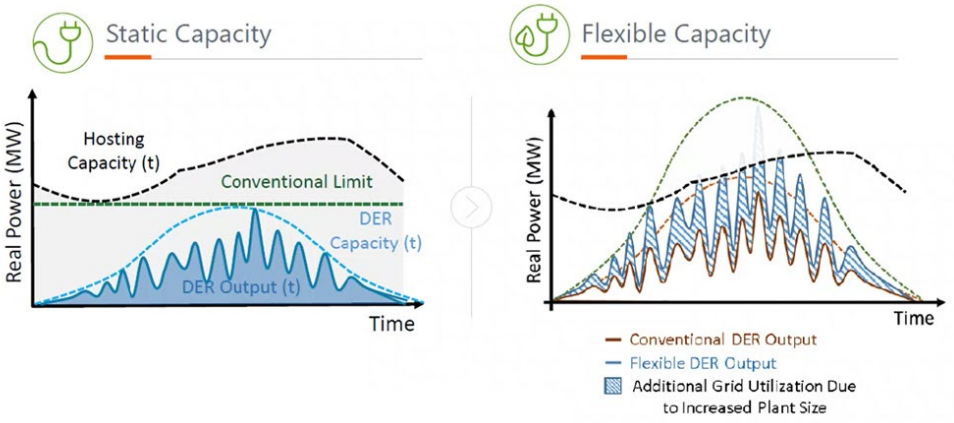
Smart inverters and distributed energy resource management systems (DERMS) form the core of still another option for improving solar and storage interconnection at the distribution level — "flexible interconnection," in which utilities have the ability to curtail or discharge power from a specific project.

The approach is widely used in the United Kingdom, where it is a "business as usual" solution for allowing interconnection while avoiding costly distribution system upgrades, said Robert MacDonald, executive vice president for U.K. sales at Smarter Grid Solutions, speaking at a U.S. Department of Energy webinar on Thursday.

The company provides advanced DERMS systems that can optimize distributed energy resource (DER) "hosting capacity by taking advantage of the latent grid capacity that's inherent within our network," MacDonald said.

In other words, utilities tend to make conservative estimates of hosting capacity, which can open opportunities for the flexible use of intermittent DERs.

"Rather than take conservative assumptions to the assignation of grid capacity to new DER sites, based on static, worst-case conditions, what we're trying to do here is, in real-time, reflect that real-time capacity that's available on the network," he said. "But, in times where that real-time grid capacity isn't available to generators with flexible interconnection, then we have the curtailment."



Static interconnection (left) versus flexible interconnection with DERMS, which allows increased integration of distributed energy resources, like storage. | *EPRI*

U.K. utilities use flexible interconnection as an interim method for getting new DERS, such as solar and storage, interconnected, but in some cases, it becomes a longer-term, permanent solution, MacDonald said. Two demonstration projects in upstate New York, both owned by Avangrid, have been using Smarter Grid's DERMS to flexibly interconnect solar projects for about a year and a half, he said.

Zachary Caruso, lead analyst for programs and projects at Avangrid, said the projects were part of New York's Reforming the Energy Vision initiative, aimed at spurring innovation and new investment in the state. The 2 MW Robinson solar project, located in Champlain, was sitting in an interconnection queue, waiting for system upgrades, Caruso recalled.

Recognizing the potential to defer the upgrades, "we sort of walked it right out of the queue, and the developer was on board, and we moved forward with it," he said.

The second project was a 15 MW installation spread over three sites in Spencerport, a suburb of Rochester, where the nearest substation did not have adequate capacity. Again, the projects were moved to the head of the queue and flexibly interconnected without costly upgrades, Caruso said.

The projects operate on both "static capacity," when the power they can put on the grid is limited, and flexible capacity, when they can increase output based on the time of day and time of year, Caruso said. The amount of curtailment necessary at both projects has been minimal, he said.

While both Avangrid projects are solar, flexible interconnection can also be used with standalone storage or hybrid solar and storage, said Karyn Boenker of the Pacific Northwest National Laboratory, who moderated the DOE webinar. Such projects would have to use "a grid-support, utility-interactive inverter with compliant certifications," such as *UL 1741 SA*, an advanced inverter safety standard, Boenker said.

Avangrid has not deployed any other flexible interconnection projects, Caruso said, but the utility sees it as "another tool in our toolbox. … It's not the be-all and end-all [that] will solve all of the DER interconnection issues that are out there, [it's] just that we've seen on some substations that there is value." ■

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FERC/Federal News

Former FERC Chair Richard Glick Sets up Consulting Shop

Partnering with Former Commission Chief of Staff on GQ New Energy Strategies

By James Downing

Former FERC Chair Richard Glick and commission staffer Pamela Quinlan announced Wednesday that they have launched a new consulting firm called GQ New Energy Strategies, which is focused on navigating customers through the clean energy transition.

Quinlan, who left FERC earlier this month, was most recently a senior policy adviser to acting Chair Willie Phillips and was the agency's chief of staff under Glick.

Glick stepped down from FERC early this year after his renomination for a new term was sunk because of opposition from Sen. Joe Manchin (D-W.Va.). After that, his job search included pursuing opportunities at law firms, but Glick told *RTO Insider* on Wednesday that setting up his own firm with Quinlan was a better fit.

"I get to work with Pamela," Glick said. "I always enjoyed working with her before. Secondly, as I got to talk with law firms, I realized that there's a lot of potential clients out there that I think might be interested in having us do work for them — and when you go to law firms, there's all sorts of conflicts with other clients and so on. You don't always get to work on the clients you want to work on."

The new consulting business avoids those conflicts and enables Glick and Quinlan to work with whom they want to on the issues they want to, he added.

Prior to joining the commission in 2017, Glick held senior positions with the Senate Energy and Natural Resources Committee, the U.S. Department of Energy and Avangrid. Quinlan has more than 18 years of experience in the sector, having previously worked at Consolidated Edison and Standard and Poor's.

GQ New Energy Strategies will provide market insights and strategy, analyze the impact of regulatory proposals on a client's business, advocate for beneficial policy and legislative outcomes, and help clients solve problems and identify opportunities as the energy business continues to change, Glick said.

He said he hopes to help clients navigate the energy transition in a way that ensures the grid remains reliable, the right investments are made, and the transition continues at a pace needed to avoid global warming. The Biden administration and other policymakers have set ambitious goals to make that transition happen in the next decade or two.

Former FERC Chairman Richard Glick | © *RTO Insider LLC*

"There's no doubt the goals are ambitious," Glick said. "Having said that, you know, and I always say this … what are your choices? Look at just extreme weather over the last five years. There's clearly a trend going on here that is very harmful to everything — our way of life, the economy, clearly our children's future and their children's futures."

The Biden administration recognizes that and is working as hard as it can under the confines of the law, he added. Some of the big challenges include greatly expanding the transmission grid, speeding up the interconnection queues and ensuring reliability as the grid takes on more intermittent, renewable resources.

"It's not going to be easy," Glick said. "But I don't think you can just throw up your hands and say you just can't do it. You have to basically go get to work and do what you can do to make to make it a reality."

The transmission agenda that Glick and Quinlan kicked off at FERC is a key part of that effort. Glick said he was hopeful their proposals would soon translate into some final rules, something Phillips has repeatedly said he wants to achieve.

The transition involves plenty of politics, which contributed to Glick needing a new job, and now Congress is paying closer attention to FERC than it has in the past.

"That has benefits, but it also has a downside," Glick said. "The downside is nominees are put through the wringer a little more vigorously than they have [been] in the past."

But Glick doesn't think any of his former colleagues on the commission are influenced by such political pressure.

"None of the four existing commissioners, I don't think they're sitting there saying, 'I better not do this because I won't be able to get another term.' That's not in their mindset; their mindset is they came to do a public service, and that's what they're doing," he said. ■

FERC/Federal News

Overheard at USEA's 2023 Public Policy Forum

WASHINGTON — The United States Energy Association saw a change of leadership and heard from speakers on the transition to clean energy at its Annual Membership Meeting and Public Policy Forum last week.

Acting USEA Executive Director Sheila Hollis, of Duane Morris, has run the organization since longtime Executive Director Barry Worthington died in 2020. She announced her term was coming to an end and that she would be replaced by former U.S. Deputy Energy Secretary Mark Menezes.

NARUC's White Speaks on the Role of the States

"We have an international programs department, and Sheila has heard me say this many, many times," said Greg White, executive director of the National Association of Regulatory Utility Commissioners. "I consider us to be a partner with USEA. USEA does training for the utilities around the world. And we go into those exact same countries, and we train the regulators."

NARUC has worked in more than 50 countries in its history and is currently helping 30 with their regulatory systems, he said. White's first overseas trip was to the country of Georgia, where he helped fix its creaky, post-Soviet grid.

"Everybody in the country was carrying a flashlight with them because in the Soviet-era buildings, the elevators usually didn't work," White said. "And so, people had to walk up many flights of stairs in the dark to get to their apartments."

Now the Georgian grid is reliable 24/7, and the days of always needing a flashlight are over, he said. That is what drives regulators here and abroad — bringing light to the world, he said. The challenge now is to make the grid's transition happen without major issues.

"We're trying to get cleaner energy that is sustainable, reliable, resilient and affordable," White said. "And we need to balance all those interests."

Most of the progress that has been made on clean energy in recent years is because of state and local policies, but now much of the conversation in D.C. on permitting reform would strip those states of at least some of their authority to site transmission lines.

"We've got some proposals in Congress right now that, quite frankly, would eviscerate the role of the states and permitting new infrastructure, especially as it pertains to the much needed electric transmission infrastructure," White said. "We believe that that would be a mistake because the states have considerably more success at siting infrastructure than the federal government."

NARUC's engagement with FERC has been more fruitful, with White highlighting the Joint Federal-State Task Force on Electric Transmission as helping to reach common policies needed to make the energy transition work.

The 'Materials Transition'

Another aspect of the clean energy transition that was not addressed much by major legislation last Congress is materials, said Michelle Foss, fellow at Rice University's Baker Institute for Public Policy.

"I'm going to take a modicum of credit for the phrase 'materials transition,'" Foss said. "The idea that the energy transition is a materials transition is because I pushed to get minerals on the agenda of an international meeting last year. And we were successful in that, and now I'm finding this phrasing is rolling around."

The conference was in Tokyo, and the Japanese government has been pushing the issue to the forefront. Foss said the G7 nations are now actively pursuing the issue.

"My own view on this is that you put materials first," Foss said. "But we didn't do that. We rolled out an enormous spending program, sending people off in all manner of directions trying to do things that they can't do, because we don't have the material supply chains to support them. And that ... is energy policy in the United States."

Foss is an alumna of the Colorado School of Mines. When she was there in the 1980s, the domestic mining industry was dying, and now it has essentially given up all of its capacity, she said. Labor and compliance with environmental laws, which brought benefits, have made the business generally too expensive here, so it moved overseas.

"China constitutes 44%, in our math, of total tonnage of nonfuel minerals in the world today, everything from metals to non-metals, to construction materials — they are it," she said. "This is not their fault; it's ours. We gave up our capacity, and China took a market share."

The U.S. is going to need secure supply chains of many minerals as it transitions to a clean economy, replacing equipment and infrastructure as they wear out, said Foss.

While much of the focus in the energy industry involves a shift away from carbon, Foss said that the element was going to be important forever because it is also used to make superior and cheaper materials that can replace metals.

"If I can displace metals with that, then I'm simply doing what humans have been doing for decades now, which is displacing metals with plastic, but a better form of it; a more advanced form of it," Foss said. ■

— James Downing

NARUC Executive Director Greg White addresses the USEA meeting with its acting executive director, Sheila Hollis, and Llewellyn King (right), host of "White House Chronicle." | *© RTO Insider LLC*

CAISO/West News

Newsom Stresses Role of Permitting in Calif. Energy Transition

Governor's Trailer Bills Cover Project Judicial Review, Animal Protections and More

By Hudson Sangree and Robert Mullin

California Gov. Gavin Newsom on Thursday released a clean energy transition plan that's long on ambition and congratulatory notes about the state's progress in meeting its renewable energy targets but short on specifics about how it will hit its aggressive decarbonization goals leading up to 2045.

Instead, the *plan* appears to be the opening salvo in a campaign to motivate California lawmakers to support Newsom's legislative package to streamline the permitting of clean energy projects across the state, including transmission lines, generating resources and factories to build clean technologies. (See *Calif. Governor, PUC Take Steps to Speed Project Development*.)

"The process-laden world we invented is now competing against us. We have to accelerate our transition," Newsom said in announcing the plan Thursday at an event at Moxion Power's first factory in the industrial city of Richmond. Founded in 2019, the company manufactures mobile batteries designed to replace diesel generators.

The plan's lengthy executive summary lauds California for a number of policy-related accomplishments, including generating 37.2% of its electricity from renewables in 2021, reaching 5,000 MW of battery storage capacity this spring and having zero-emission vehicles claim 21% of the state's automobile market.

It also outlines the state's three main challenges in implementing its energy transition: planning for high electrification, deploying clean energy resources and ensuring electric grid reliability during extreme events.

And buried within that outline is what looks to be Newsom's most concrete concern.

"Realizing California's clean electricity goals reliably, affordably and equitably requires an unprecedented scale of new clean, diverse electric resources to match electricity demand growth," the plan says. "This acceleration requires rethinking and updating permitting, procurement and project development processes to bring clean energy infrastructure online quickly."

The Agenda

Newsom's legislative proposals are contained in "trailer bills," so-called because they follow the governor's proposed *budget* for fiscal year 2023/24, which he issued in January and revised in May. Newsom must find lawmakers willing to introduce these bills.

One *bill* would establish a central procurement authority to ensure the state has sufficient electricity resources to avoid shortfalls as it struggles with extreme heat, tight supply and a changing resource mix across the West.

The governor's proposal would give the California Public Utilities Commission the option to name the Department of Water Resources or an investor-owned utility to procure energy for the state's load-serving entities, including public utilities and community choice aggregators. (See *Calif. Governor Seeks Central Procurement Authority*.)

Another would *streamline* judicial review of certain clean-energy and transportation projects by requiring that challenges to the projects under the California Environmental Quality Act be resolved within 270 days, including lawsuits and appeals. A related *measure* would streamline procedures for the preparation of the public record for court review of CEQA challenges.

Newsom has also proposed a bill that would allow but mitigate the removal of western Joshua trees, iconic California desert plants the state Fish and Game Commission is considering listing under the California Endangered Species Act but that occupy land slated for utility-scale solar arrays.

"The western Joshua tree occurs across a large portion of California's desert region where renewable energy and housing development are essential for the state," the proposed bill says. "Due to the widespread distribution of the western Joshua tree across the California desert region … there is a critical need to immediately conserve the species while also ensuring timely and efficient permitting mechanisms for activities within its range. Making a transition to a carbon-free energy future and providing housing for Californians are among the highest of state priorities."

Newsom's trailer bills also include *one* to repeal state statutes that designate 37 "fully protected" animal, fish and bird species.

"The bill would reclassify the 37 fully protected species so that 15 will be listed as threatened under the California Endangered Species Act, 19 will be listed as endangered under CESA, and three will have no listing status and would retain the protections afforded to species generally under the Fish and Game Code," a *fact sheet* on the bill says.

Those remaining in the threatened category would include wolverines and sandhill cranes. California condors and bighorn sheep would remain listed as endangered, with 17 others. Those remaining unlisted would include peregrine falcons and brown pelicans.

On Thursday, the State Senate budget subcommittee on resources, environmental protection and energy was scheduled to discuss the proposals as part of the budget process, which can lead to quicker approval and avoid measures getting held up in policy committees.

But the subcommittee's staff recommended that the bills, if they find sponsors, should be heard in policy committees, such as the Energy, Utilities and Communications Committee and the Natural Resources and Water Committee.

"The 10 trailer bill proposals above were provided to the Legislature and the public on May 19, 2023," staff wrote. "Because of the complexity of these issues and limited time to deliberate, it would be reasonable and prudent for these proposals to [be] reviewed through the policy process."

'Running Against Time'

At Thursday's event, Newson laid out the need for permitting changes in strong — if extreme — terms, as the world faces the growing strains of climate change.

"We need to build; we need to get things done," he said. "This is not an ideological exercise. We're running against time. Mother Nature bats last; she bats a thousand. She's chemistry; she's biology; she's physics. She doesn't mess around. We don't have time to hold hands and talk about the way the world should be. We've got to go."

Newsom also suggested that inaction on permitting represented a test for democratic government.

"If we don't build, democracy is questioned [based on] our capacity to deliver," he said. "Why do you think so many of these authoritarians are asserting themselves in their might [and] muscle, not just around the world, but in some other parts of this country? It's because they say we can't get things done anymore." ■

CAISO/West News

Western Grid Challenges Weighed at WCPSC Meeting

By Hudson Sangree

CPUC Commissioner John Reynolds (right) moderates a panel with (from left) CAISO CEO Elliot Mainzer, SCE CEO Steve Powell, PG&E CEO Patti Poppe, SDG&E CEO Caroline Winn and CEC Vice Chair Siva Gunda. | © *RTO Insider LLC*

NAPA, Calif. — The CEOs of the state's three largest utilities and CAISO sat down for a panel discussion last week on switching to clean energy and maintaining reliability amid extreme heat, destructive storms and pandemic-caused supply chain problems.

"Today in the West, we face many common challenges in the energy sector," said California Public Utilities Commissioner John Reynolds, who moderated the discussion at the Western Conference of Public Service Commissioners' annual meeting at a Napa Valley golf resort.

"We ask ourselves common questions like, 'How do we integrate the increasing amount of renewables on the grid?'" Reynolds said. "'How do we plan for and adapt to extreme weather events and changing climate, which affect customer demand, generation resources and infrastructure in ways that we are still continuing to understand? In the face of these challenges and others, how do we ensure that customers are delivered clean, affordable and reliable energy?'"

The panelists who addressed Reynolds' questions were CAISO CEO Elliot Mainzer, California Energy Commission Vice Chair Siva Gunda, Pacific Gas and Electric CEO Patti Poppe, Southern California Edison CEO Steven Powell and San Diego Gas & Electric CEO Caroline Winn.

Reynolds asked first about wildfires and extreme weather. To Powell, he posed a question about how SCE had employed "situational awareness" to deal with wildfires.

SCE CEO Steve Powell | © *RTO Insider LLC*

"Over the last five years, we've installed more than 1,600 weather stations on our circuits in high fire threat areas," Powell responded. "That means most circuits have two to three weather stations on them. Those weather stations give us enough granularity, when combined with other forecasts and detailed models, to get a lot more targeted about where we have to deploy our public safety power shutoffs."

Power safety power shutoffs (PSPS) are the intentional blackouts Western utilities use to prevent their equipment from sparking wildfires during dry, windy conditions, usually in late summer and fall. When SCE started using PSPS in 2018, it would turn off entire substations or service areas.

"We're now able to break that down and get specific parts of circuits to take off, and it's allowed us to decrease the amount of customers [affected by] a PSPS outage by 80 to 90% in most cases," Powell said. "So that's been a huge part of that situational awareness."

Reynolds asked Poppe about this winter's series of "atmospheric river" storms that drenched California between December and March.

"Can you tell us about the operational challenges that these kinds of extraordinary events present for utilities?" he asked.

The season started with a 6.2-magnitude earthquake off the coast of Northern California that knocked out power to thousands of customers, followed by one storm after another that wreaked havoc on PG&E's infrastructure, Poppe noted. Starting with the quake, "we were in emergency response mode until mid-April, so we definitely had a lot of opportunities to learn," she said.

"We would have an atmospheric river with 400,000 customers out and back on within 24 hours; 300,000 customers out and back on within 24 hours. It just went on and on and on," Poppe said.

Weather forecasts and advance preparation played a big part, she said.

PG&E CEO Patti Poppe | © *RTO Insider LLC*

"We could pre-stage things like backup generation and substations before the storm hit," she said. "So, we could respond and have the crews in the right places at the right time and have our resources and our equipment in the right places at the right time, and that is extraordinarily effective."

Mutual assistance from other Western utilities helped PG&E cope, she said.

"We could not have gotten through all of these events without the support from all of the states and all of the utilities in the West who, when we called, you answered," she told the audience.

Supply Chain Issues

Reynolds asked Winn about how SDG&E had dealt with supply chain issues at a time when utilities are "contracting and building swiftly to meet our midterm reliability needs."

The state has struggled with blackouts and near misses the past three summers, and utilities have been connecting thousands of megawatts of new clean energy and storage

CAISO/West News

resources to head off further problems.

"When you think about the work that we're doing on climate change adaptation … [and] extreme weather; when you think about the work that we're doing to meet California's aggressive clean energy goals; and when you think about the pandemic, everything that we need to do needs to be different," Winn said. "It needs to be different than we have historically done."

For years, SDG&E bought materials on a "just-in-time" basis, ordering from suppliers a few weeks before materials were needed.

The pandemic changed that, requiring longer-term planning, she said. Complications from adding large amounts of rooftop solar power and demand from electric vehicle charging are also "changing the game."

SDG&E has seen demand drop by 2% a year since 2014 because many property owners are adding rooftop solar panels," Winn said. But the utility is now expecting large increases from EV adoption, which jumped 25% in one year in San Diego, and from homeowners who are swapping out gas appliances for electric heat pumps, water heaters and stovetops.

The utility is also tripling the amount of storage on its system and needs dozens of larger transformers to handle the 70 powerful DC fast chargers it plans to install.

"All of that needs supply chain, and we can't do things the way that we used to," Winn said. "Now we have to meet with all of our major customers and understand: 'What is your electrification plan? What is your load-growth plan?' And be able to plan for that in a much more detailed way. It's just required.

"We're ordering things early, whether we need it or not," she said.

Load Forecasting

Gunda said the CEC's load forecast is changing because of vehicle and building electrification.

California recently hit its goal, two years ahead of schedule, of having 1.5 million EVs on the road. The state is aiming to entice property owners to install 6 million heat pumps in the coming years.

"All of these things bring uncertainty" in load forecasting, Gunda said.

The CEC has begun using demand forecasts with base case and high-electrification scenarios. In the high-electrification scenario, it plans for 6 million EVs by 2030, even though that may not happen.

SDG&E CEO Caroline Winn | © *RTO Insider LLC*

It's also factoring in extreme weather, he said.

"In 2022, for most of the year, we were tracking average weather in California," he said. But during a severe heat wave that spanned 10 days in September, "we deviated 15% from what our planning assumption was. So, we were 7,000 MW off what we were expecting in September. That's what we're trying to bring into our forecast."

Western Markets

The September 2022 heat wave drove CAISO to the brink of ordering rolling blackouts for the second time in three years.

How can Western states collaborate to serve customers in extreme weather? Reynolds asked.

Mainzer said CAISO's interstate Western Energy Imbalance Market (WEIM) has been important for regional reliability and could be even more effective if it expands from a

CEC Vice Chair Siva Gunda | © *RTO Insider LLC*

CAISO CEO Elliot Mainzer | © *RTO Insider LLC*

real-time market to a day-ahead platform, as planned. The ISO is preparing tariff language to send to FERC for a WEIM extended day-ahead market (EDAM).

"Last summer, when we were right in the middle of that incredible heat wave, there was a lot of focus on California's [strained grid] … but there was also all-time record demand in the Western United States," Mainzer said. "We had 167,500 MW of demand [in the Western Interconnection] on Sept. 6, 2022, so California was in distress, but other parts of the West were also struggling."

"It was kind of amazing, from the control center, to watch the Energy Imbalance Market as it was cycling energy around on a five-minute basis across the West, helping not only California but other parts of the West that were struggling with reliability to keep the lights on," he said.

If CAISO has a day-ahead market, "where we could look out across the broader footprint in the incredibly diverse Western United States and have the visibility into the overall sufficiency of that footprint, we would be able to move electricity to where it is most needed to be able to pre-emptively mitigate energy emergencies," Mainzer said.

Energy emergencies in California the last three summers made wholesale electricity prices soar at key Western trading hubs.

A West-wide day-ahead market would also bring reliability benefits during times of "volatility and uncertainty that we see on the grid. It's going to be the reliability component of regional coordination that I think more and more is going to see an even greater value," Mainzer said. ■

CAISO/West News

Wash. Approval of Pumped Storage Project Sparks Dissent

$2 Billion Facility Would Generate 1,200 MW, but Tribes and Environmental Groups Oppose It

By John Stang

Washington's Department of Ecology last week issued a water quality certificate for a pumped storage project along the Columbia River, sparking protests from area tribes and some environmental organizations because the location contains sites sacred to the Yakama Nation.

Ecology issued the certification with conditions to ensure the construction and operation of the proposed Goldendale Energy Storage Project meet state water quality requirements.

"Conditions include following specific best practices, requirements for getting future Ecology permits and monitoring and notification requirements," the agency said in a *statement*.

Opponents have 30 days to appeal the Ecology Department's decision.

Boston-based Rye Development is hoping to build Washington's first pumped storage project for $2 billion in southern Klickitat County near the John Day Dam and commence operation between 2028 and 2030. The project is designed to generate 1,200 MW of energy. (See *Wash. Pumped Hydro Project Faces Permitting, Obstacles*.)

The project would include two lined 600-acre water reservoirs that are 60 feet deep and separated by 2,100 feet in elevation. One reservoir would be on the river shore, the other atop a cliff adjacent to the Tuolumne Wind Project. An underground pipe would connect the reservoirs, with a subterranean electricity generating station along the channel. Water would flow from the upper reservoir to the lower one to power the four-turbine generator station and would then be pumped back up to the upper reservoir in a closed-loop system.

The water quality certification is one of many approvals needed before the project can be built.

FERC and the U.S. Army Corps of Engineers are reviewing a hydropower license and a permit to fill federally regulated waters, respectively. Under the Clean Water Act, the federal agencies require a water quality certification from the Ecology Department before making their decisions.

FERC also released a draft federal environmental review April 6 and is accepting public comments through June 6.

The pumped storage project would be on private land that Rye Development leases from NSC Smelter, which owns the former site of the Columbia Gorge Aluminum smelter site one mile upstream from the John Day Dam. The site is within a large strip of land in southern Klickitat County that the county has zoned for renewable energy projects.

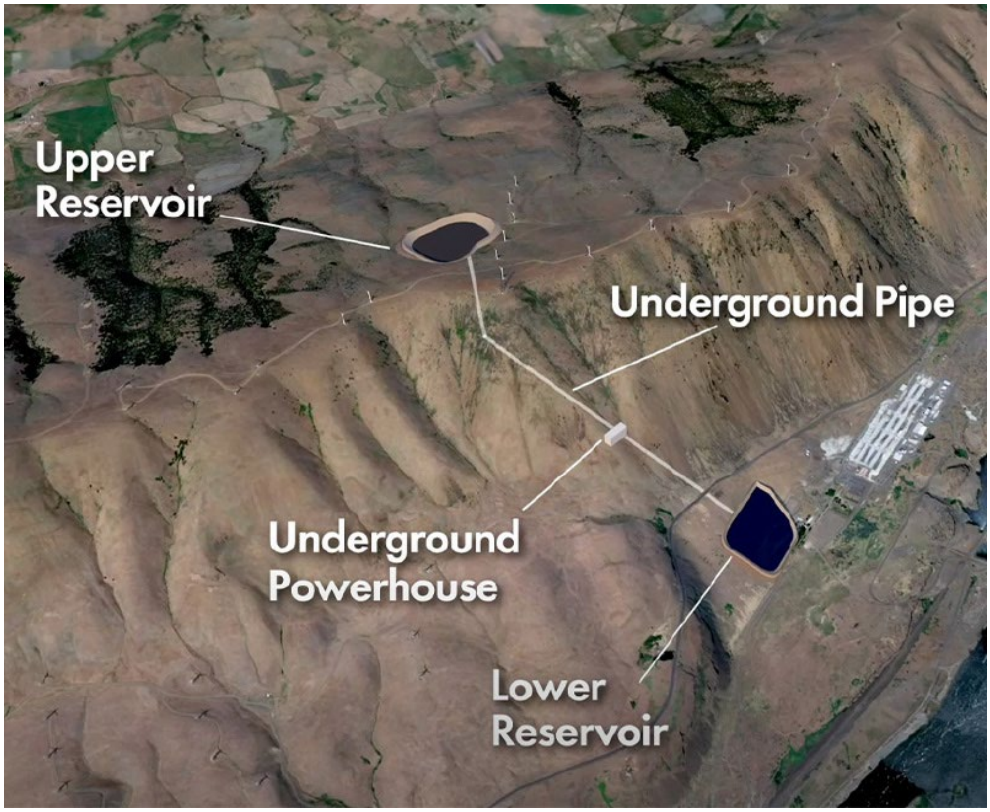
Tribal and environmental opponents issued a press release protesting against the state certification.

While the project is not on Yakama reservation land, it is on property used for sacred ceremonies, and it has a historical connection to the tribe. The project area includes a longhouse, an ancient village site and other sacred sites. Since 1855, the tribe has had treaty rights to fish and hunt in the area, as well as the right to protect burial grounds and religious sites across a vast area in south central and southeastern Washington.

The Yakama, the Nez Perce Tribe, the Confederated Tribes of Warm Springs and the Confederated Tribes of the Umatilla Indian Reservation oppose the project. This year, the Affiliated Tribes of Northwest Indians, representing 57 tribal governments, and the National Congress of American Indians joined the opposition.

"A clean energy future must uphold federal trust and treaty obligations that consider the cultural and health impacts of these projects on sacred sites," Alyssa Macy of the Warm Springs nation, who is also CEO of Washington Conservation Action, said in a press release from several tribes and environmental organizations. "These parts of our identity — the land, the roots and the water — are a part of our collective history, and we must not erase them."

"Pumped storage is a critical tool in facilitating our transition to clean energy. However, the current siting of this project reinforces the exploitation of our tribal neighbors and should have been rejected," said Sept Gernez, acting director of the Washington State chapter of the Sierra Club. ■



Located along the Columbia River near the John Day Dam, the Goldendale Energy Storage Project would consist of two reservoirs separated by 2,100 feet in elevation. | *Rye Development*

CAISO/West News

FERC Settles with 2 DR Firms over Inflated Bids in CAISO

Both OhmConnect and Leapfrog Power Failed to Meet Market Obligations

By James Downing

FERC last week approved settlements with two demand response aggregators for allegedly bidding more resources than they could provide to CAISO's market.

OhmConnect (*IN23-6*) agreed to pay a fine of $141,094 and disgorge $8,906 to the ISO, while Leapfrog Power (*IN23-7*) agreed to pay $73,880 and disgorge $46,120. Both companies agreed to heightened compliance monitoring in order to shut down enforcement probes over their DR bidding activities.

Both firms were participating in the California Public Utilities Commission's Demand Response Auction Mechanism (DRAM) pilot program, in which they contract with load-serving entities to provide a set amount of demand response every month. The program required them to tell the LSE they were working with how much DR they would have available in a month 90 days ahead of time.

Ohm's allegedly problematic bids happened between January and June 2018, and it made $8,906 more than it should have, while Leapfrog's came between February and August 2019, and it made $46,120 more than it should have.

The two have different business models, with the California-based Ohm focusing on home energy management via customers' smart meters. It allows residential customers to earn rewards for their energy reductions, which it sells into the markets.

Ohm signed up to provide 109 MW of DR for the 2018 delivery year, but it was not able to sign up enough customers to provide that much, with shortfalls ranging from 32 to 63%.

Leapfrog connects electric vehicle, battery storage, smart thermostat and other flexible technologies to provide DR and enrolls them in the wholesale markets in aggregated portfolios. Leapfrog was a startup and it first bid into the DRAM program in 2018 for 2019 delivery, but it was never able to sign up enough customers to support its bids. Most of the bids it made from February to August exceeded the registered metered load of customers it had signed up, with shortfalls ranging from 54 to 98%.

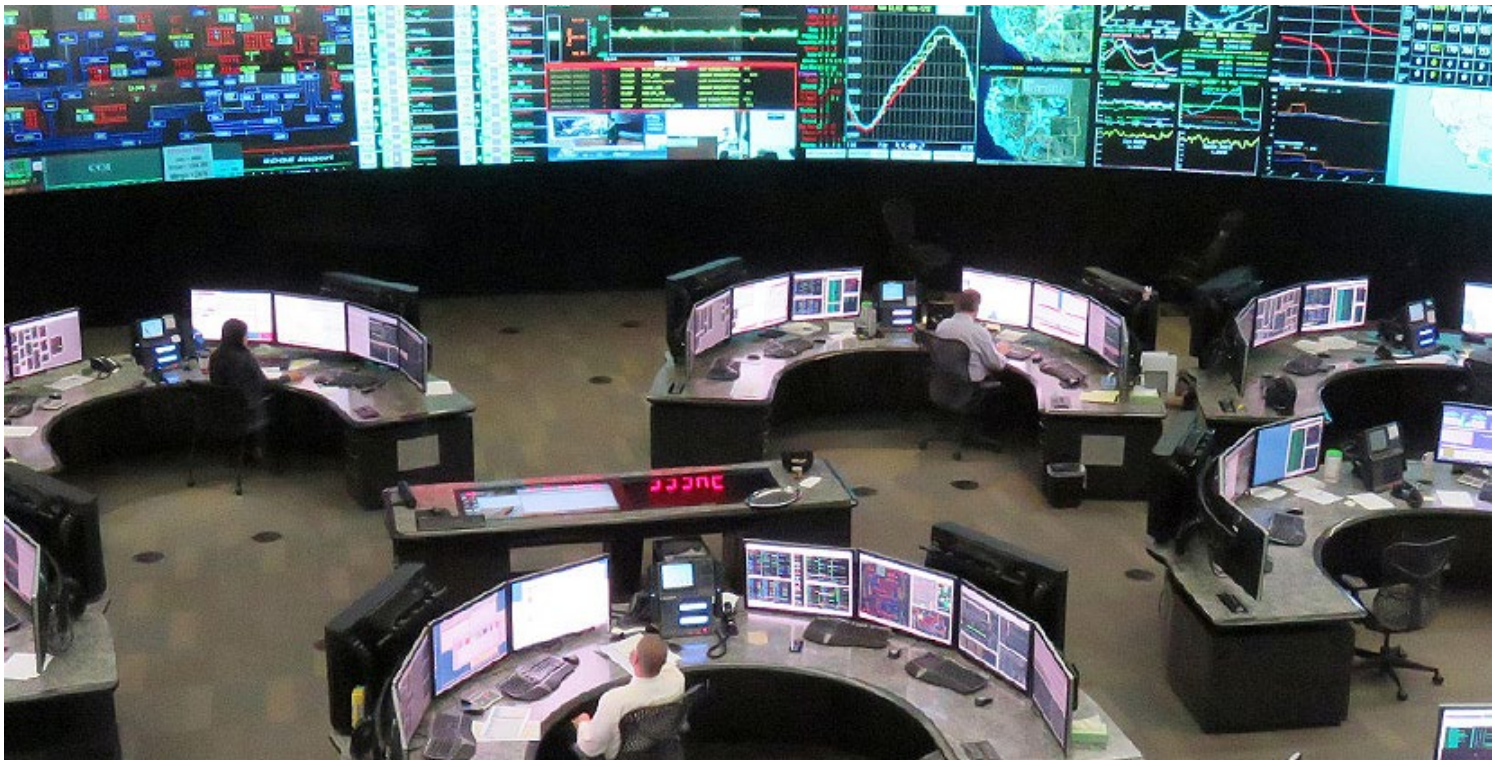
CAISO's tariff requires that market participants make bids from resources that are reasonably expected to be available and capable of performing at the levels specified in their bid and to remain so based on all information that is or should have been known to the market participant when their bids were made.

FERC Office of Enforcement staff determined that both Ohm and Leapfrog made a "substantial majority" of their bids when they could not reasonably expect to fulfill them during the relevant periods. In both cases their bids "exceeded the registered metered load of all" their customers.

Both firms stipulated to some facts laid out in the agreement, but neither admitted nor denied the violations that enforcement staff alleged.

Both firms cooperated with the investigations and FERC found that the deals they signed with its staff were fair and equitable resolutions of the matters concerned and are in the public interest because they reflect the allegations' seriousness and are in line with the regulator's penalty guidelines.

CAISO will distribute the $55,000 in disgorgements on a pro-rata basis to its network load. ■



CAISO Control Room | *© RTO Insider LLC*

CAISO/West News

Regional AC Tx Line Approved in Parallel to SunZia

500-kV RioSol Line Designed to Deliver Renewable Energy to NM, Ariz.

By Elaine Goodman

The Bureau of Land Management's record of decision for Pattern Energy's SunZia transmission line was also the final major approval needed for SouthWestern Power Group (SWPG)'s RioSol line, which will run next to SunZia.

The BLM *record of decision*, issued this month, approves an amendment to a right-of-way grant that will allow construction and operation of two transmission lines.

One of those lines is Pattern Energy's SunZia transmission project, a 550-mile line from central New Mexico to south-central Arizona. (See *SunZia Project Wins Final Approval, Signs Offtakers*.)

The second line is SWPG's RioSol line, which will generally follow the same route as SunZia.

SWPG started developing the two lines in 2006 and sold one of the lines to Pattern Energy last year. Though the two lines together were initially known as SunZia, Pattern acquired the SunZia name for the single line it purchased.

The two lines have different purposes, SWPG General Manager David Getts told *RTO Insider*.

The path of the RioSol transmission line will parallel that of the Pattern Energy's SunZia line, but it will serve the purpose of delivering renewable energy to communities along the route. | *SouthWestern Power Group*

The SunZia line will be a 525-kV DC line with 3,000 MW of capacity. It will carry energy from the SunZia Wind project in New Mexico to central Arizona to ultimately serve customers in Arizona and California. Getts described it as an "express line" across the 550-mile corridor.

SWPG's RioSol line will be a 500-kV AC line with 1,500 MW of capacity. Because it is an AC line, interconnections will be easier, and SWPG envisions RioSol delivering renewable energy regionally in New Mexico and Arizona through connections to multiple substations along its route.

SWPG expects to start the process to obtain negotiated rate authority from FERC either this year or next.

And the company is aiming to start construction on RioSol in 2026, depending on progress of the SunZia line, with RioSol operations commencing in 2028. Construction of SunZia is expected to start this year, with a 2026 in-service date.

Melanie Barnes, BLM New Mexico state director, called the record of decision an "exciting milestone" for the transmission project.

"This effort represents an important step in the development of our country's renewable energy and transmission infrastructure," Barnes said in a statement.

According to Pattern Energy, the transmission route was originally approved in 2015. But the route was adjusted to reduce conflicts with the White Sands Missile Range. The revised route also partly parallels the Western Spirit Transmission line, minimizing environmental impacts along the segment. ■

ERCOT News

ERCOT Technical Advisory Committee Briefs

New Ancillary Service Products Target System Reliability

ERCOT staff last week delivered their first annual settlement report on firm fuel supply service (FFSS), an ancillary service that was added in the wake of the February 2021 winter storm.

Settlement analyst Maggie Shanks told the Technical Advisory Committee on May 23 that ERCOT designated 19 generation resources as primary FFSS resources during the Nov. 15-March 15 obligation period at a clearing price of $6.19/MW-hour, or $18,000/MW. The grid operator procured 2,940.5 MW of FFSS capacity at a cost of $52,839,535.

An additional $4,768,842 will be added for fuel replacement costs during the two winter watches ERCOT issued in December. The total cost will be reduced by clawing back an estimated standby fee of more than $25 million. The clawback settlements began in May and will end in September. Fuel replacement costs will be settled July 31-Aug. 1.

Clawback charges are assessed to FFSS resources that do not meet 90% availability in their availability plan during a winter weather watch's hours or if they fail to come online and stay there during an FFSS deployment because of nonfuel-related issues.

ERCOT assessed clawback charges for 90 days for seven FFSS resources that did not reflect their availability. Another resource received a clawback charge for 15 days under the second scenario.

The Texas Public Utility Commission directed ERCOT to develop the FFSS product after the Legislature passed a bill in 2021 requiring ancillary or reliability services that address reliability during extreme cold weather conditions. The service is procured through a request-for-proposals process before the obligation period begins.

The grid operator is adding another new ancillary product in June with ERCOT contingency reserve service (ECRS), or capacity that can be sustained at a specified level for two consecutive hours. It is meant to be deployed to restore frequency within 10 minutes of a significant deviation; to compensate for intra-hour net load forecast uncertainty when large amounts of online thermal ramping capability are not available; or when limited capacity is available for dispatch.

ECRS is also a result of the PUC's directive to offer more reliability services.

Matt Mereness, senior director of market operations and implementation, said staff have been holding weekly meetings and workshops to prepare market participants. The service will become operational June 10, when telemetry will begin including ECRS values at 12:01 a.m.

Mereness also said staff are re-evaluating the scope, cost and schedule for the real-time co-optimization (RTC) project, which has been on hold since the 2021 winter storm. Staff are still eyeing a potential midyear restart for the program; it would expand ERCOT's real-time market by clearing energy and ancillary services every five minutes, as most other grid operators already do.

ERCOT leadership has said RTC's reliability benefits in addressing future operational challenges make the tool a strategic priority.

ERCOT's Technical Advisory Committee has compromised with staff on language for firm fuel supply service, one of two new reliability services added since the 2021 winter storm. | © RTO Insider LLC

ERCOT Compromises on FFSS Product

TAC members endorsed a nodal protocol revision request (*NPRR1167*) intended to improve the new FFSS product, but not before accepting staff's suggestion to remove language disqualifying or decertifying resources from the firm-fuel program. That language will be brought back to the committee as a separate NPRR.

ERCOT staff and stakeholders disagreed over the types of performance failures that would start the disqualification process, with some stakeholders saying the failure must be related to a fuel-related issue. Staff said they want to be able to address a situation where there are multiple instances of the unit not being able to run, regardless of the reasons.

ERCOT had *filed comments* proposing to remove references to fuel-related issues that would disqualify or decertify a resource from FFSS participation for "repeated instances of the specified performance failures." Removing the fuel-related limit is appropriate, staff said, because "FFSS is a high-reliability product."

"Given that the ERCOT board has a tendency to support ERCOT staff on issues, I would hate for this to be a lost opportunity here at TAC," said Eric Goff, who represents residential consumers. "I think it would be good if we can find some sort of middle ground on this issue."

After a sidebar discussion, staff agreed to accept the NPRR as approved by the Protocol Revision Subcommittee on May 10 and bring back the decertification language in another revision request.

Generators supported the PRS-approved language and the proposed future NPRR, saying ERCOT's suggestions make performance

ERCOT News

issues too financially unfavorable.

The NPRR includes:

- a requirement in the availability plan's definition that plan updates be made within 60 minutes after the change in availability when a resource submits the plan after a change;
- more detailed direction to incorporating an alternate generation resource that may be designated as an FFSS resource;
- another requirement that ERCOT post an FFSS offer's disclosure report after each procurement period;
- clarified language regarding procedures for communication between ERCOT and qualified scheduling entities (QSEs) when restocking fuel post-FFSS deployment; and
- moving the obligation to test prospective FFSS resources before the procurement process.

Another Reliability Tool for ERCOT

TAC overcame concerns about "optics" in approving a revision request (*NPRR1143*) that allows ERCOT to give charging instructions to energy storage resources during a Level 3 energy emergency alert.

"This NPRR is not a fall-on-the-sword issue for us, but we feel strongly that the optics of charging and allowing charging of batteries in an EEA Level 3 when you have involuntary load shed is horrendous," said Mark Dreyfus, who represents the city of Eastland and other municipalities in the consumer segment.

"I understand people's concerns about the optics … but I think at the end of the day, failing to give ERCOT as many reliability tools as they can have is probably a bigger risk," countered NextEra Energy Resources' John Ritch. "The optics could cut either way, right? People are concerned about the optics of load being shed while batteries are charging, right? There's an alternative scenario where frequency was healthy for a while and batteries weren't charged, and then there's a subsequent event where batteries would have been useful and more load is lost, right?"

"I think at the end of the day, the guiding objective here should be to give ERCOT the broadest number of reliability tools that they can have," Ritch added.

The NPRR was amended to include *comments from ERCOT* clarifying language that has since been added to the protocols by NPRR1002.

The measure passed 22-1 with six abstentions. South Texas Electric Cooperative (STEC) cast the lone dissenting vote, saying charging a battery when firm load shed is occurring is "unacceptable."

"At the end of the day, we have members to serve, and it is of the highest importance to us to ensure that they have the power they need so they can survive," said Clif Lange, STEC's general manager and TAC's chair. "Some might call it an optics issue, but we believe it is a public welfare issue."

Fuel-cost Discussion Tabled

The committee tabled *NPRR1177*, which requires resources to file exceptional fuel costs that include contractual and pipeline-mandated costs. The NPRR avoids the risk of real-time mitigation that results in unrecoverable financial losses and improves ERCOT's and the Independent Market Monitor's ability to verify these costs.

TAC scheduled a *June 5 webinar* to further discuss the measure.

The move came after the consumer segment filed *comments* May 22 proposing a 2027 sunset to ensure the measure is replaced with a permanent solution and created three additional guardrails: requiring QSEs to complete an attestation that the forward-fuel contract costs are known and actual; allowing ERCOT to prohibit a QSE or resource from using the functionality if they submit offers that exceed their costs; and directing the grid operator to develop standardized fuel contract language.

ERCOT staff asked for more time to review the comments that were submitted the day before, saying they believe additional guardrails are needed but that some of the changes need to be clarified.

Constellation Energy Generation's Andy Nguyen, who drafted and filed the NPRR in April, said he would have "heartburn" over the delay and offered to provide desktop edits.

"The current protocols do not have a cost recovery mechanism for mitigation losses," Nguyen said.

Credit Group's Leadership Approved

TAC's combination ballot, passed unanimously with one abstention, endorsed the Credit Finance Sub Group's leadership. Austin Energy's Brenden Sager will serve as chair, and NRG Energy's Loretto Martin will serve as vice chair; both ran unopposed.

The group was created this year, replacing the Credit Working Group. It comprises credit professionals responsible for ensuring that appropriate procedures are implemented to mitigate credit risk in ERCOT in a "fair and equitable" manner.

The combo ballot included five NPRRs, two revisions to the Nodal Operating Guide (NOGRRs) and a single change to the Retail Market Guide (RMGRR) that, if approved by the board, would:

- *NPRR1161*, *NOGRR246*: clarify that intermittent renewable resources that remain synchronized to ERCOT, but are unable to provide reactive power when not providing real power, do not have to notify ERCOT other than their real-time telemetered status.
- *NPRR1166*: change the expiration date for DC ties' schedule information protected status from 60 days after the applicable operating day to the date on which ERCOT files the report with the PUC, as required by transmission export rates' rules related to energy imports and exports over the ties.
- *NPRR1168*: change the Texas standard electronic transaction (Texas SET) to "Establish/Change/Delete CSA Request" and add new sections to the protocols related to administering requests to change end dates for active continuous service agreements (CSAs).
- *NPRR1169*: expand the qualifications for generation resource that may be an FFSS resource or an alternate.
- *NPRR1178*: clarify and update expectations for resources providing ECRS.
- *NOGRR253*: align the guide's language regarding ECRS and nonspin with NPRR1178's proposed revisions and NPRR1096's proposed protocol language. The NOGRR would also clarify that ERCOT may manually deploy load resources, other than controllable load resources that are providing ECRS or responsive reserve, to maintain a minimum 500 MW of physical responsive capability reserves on dispatchable resources to balance demand with supply while maintaining stable grid frequency for smaller disturbances.
- *RMGRR172*: update the Texas SET transaction's name to "Establish/Change/Delete CSA Request" and add new sections to the guide that describe how to cancel a pending CSA through MarkeTrak. ■

— Tom Kleckner

NECPUC 75th Annual Symposium

NE Stakeholders Support Developing Time-varying Rates

By Jon Lamson

From left: Long Lam, Brattle Group; Travis Kavulla, NRG; Commissioner Carleton Simpson, New Hampshire Public Utilities Commission; Consumer Counsel Claire Coleman, Connecticut Office of Consumer Counsel; and Amy Boyd, Acadia Center | *© RTO Insider LLC*

STOWE, Vt. — As New England plans how to cope with peak winter electricity demand with a growing reliance on renewables, energy leaders in the region are calling on the states to look at developing time-varying rates to reduce costs and environmental burdens.

Speakers at the 75th New England Conference of Public Utilities Commissioners Symposium last week generally agreed on the need to develop rate structures that would better allow customers to respond to market signals, incentivizing them to reduce energy consumption during periods of limited energy supply. The vast majority of customers in the region currently pay flat rates, regardless of the amount of stress on the grid.

"Advanced rates are critical to any cost-effective decarbonization strategy," Long Lam, a senior associate at the Brattle Group, said. Lam pointed to a *2020 study* from the Brattle Group that analyzed data from time-of-use rate pilot programs in Maryland. The study found that customers saved an average of 5 to 10% on their bills, while reducing summer peaks by 10.2 to 14.8% and non-summer peaks by 5.1 to 6.1%.

Lam also said that moving away from flat rates could be especially important as homes and vehicles electrify, and that rates should be designed to accommodate these changes.

Travis Kavulla, vice president of regulatory affairs at NRG Energy, argued that time-of-use rates should be the default rate design for consumers across the region, saying that customers would be far less likely to take the initiative on their own to opt-in.

"If you don't have time-of-use rates … you're putting consumers in a position where they're just along for the ride," Kavulla said.

By reducing energy peaks, Kavulla said, the region would be able to minimize stress to the grid, along with the financial and environmental costs of bringing heavily polluting peaker plants online to meet demand.

In a *white paper* Kavulla published earlier this year, he highlighted the untapped potential of smart meters and the need to develop increased demand flexibility incentives for utilities and customers.

"In nearly every other market, we have empowered consumers to decide whether, when, and how to buy products — and those decisions inform but are not supply-side decisions," Kavulla wrote. "So too it should be in the electricity economy."

But developing new rates will not be a simple process, with potential impacts reverberating throughout the energy industry and in households across the region.

"We need to be extremely thoughtful and have a thoughtful stakeholder engagement process from the very beginning," said Carleton Simpson, a commissioner at the New Hampshire Public Utilities Commission. "We need to take the time to understand what the impact would be for many different groups of folks out there."

Claire Coleman, who serves as consumer counsel for the state of Connecticut, was open to changing the default rates while keeping ratepayers in mind.

"There are strong affordability reasons to choose time-varying rates as the default option," Coleman said. "I think the default option should be the one which the majority of customers benefit from."

Coleman noted that customer education and engagement would be essential for successful implementation and that "shadow billing" options could help customers compare how different rates would affect their bill. She also spoke in favor of developing low-income discount rates to help customers struggling to pay their energy bills, which she said would be particularly important to equitably distribute the costs of the energy transition.

"Not every customer has the same ability to pay," she said.

In order to accommodate customers with special needs or limited energy-use flexibility, the speakers agreed that if time-varying rates do become the default, customers need to have other options.

"We absolutely have to have an opt-out program where people can opt out if the rates are not working for them," said Amy Boyd, vice president of climate and clean energy policy at the Acadia Center. ■

Overheard at NECPUC 75th Annual Symposium

By Jon Lamson

STOWE, Vt. — Transmission planning, equitable energy siting, and making the most of billions in federal funding were among the key topics as regulators, industry members, and energy experts gathered at Stowe Mountain Resort for the New England Conference of Public Utilities Commissioners' (NECPUC) 75th annual symposium last week.

"We can have a better, more efficient permitting process without compromising environmental or social justice values," said U.S. Sen. Peter Welch (D-Vt.), opening the conference as legislators in Washington continued their negotiations over permitting rules amid debt ceiling talks. "A lot of environmentalists really want to accelerate the timeline when it comes to clean energy projects … that's one area where I think there's some potential for us to make some progress."

Welch said that building clean energy projects at the local level will be a far more difficult task than drafting federal legislation. But he expressed hope that successful projects early on could help build broader support for additional infrastructure.

"It's not a one-size-fits all deal that we have here," Welch said, citing the need to balance affordability, clean energy and reliability. "You guys have your work cut out."

A Focus on Equity

Using the clean energy transition to address historical environmental injustice was a recurring theme in many of the symposium's panels and discussions.

"I see energy as the Trojan horse to usher in equity," said Shalanda Baker, director of the Office of Economic Impact and Diversity at the U.S. Department of Energy. Baker spoke about how she grew up living with energy insecurity and how low-income families are frequently forced to choose between energy, food and medicine.

"It's a matter of life and death for so many households," Baker said.

Baker urged better engagement with environmental justice communities and said states should look at different energy models, including community ownership programs. She called on regulators to work to right the wrongs of historical energy siting, where the greatest burdens of infrastructure have typically fallen on low-income neighborhoods and communities of color.

Vermont PUC Commissioner Margaret Cheney (left) and DOE's Shalanda Baker | *© RTO Insider LLC*

While frontline communities have dealt with increased pollution from energy infrastructure, they often simultaneously spend a larger portion of their income on energy bills, are often more susceptible to climate impacts such as extreme heat, and have the least access to clean energy programs related to rooftop solar, storage and energy efficiency, Baker told the symposium.

"These are not accidents; we've made these choices as policymakers," Baker said. "As you are engaging utilities on how they are siting facilities, we have to think about this through the social lens. … If we're not careful and vigilant, we will replicate that inequality."

David Cash, EPA's New England regional administrator, also emphasized the role regulatory agencies have historically played in perpetuating legacies of environmental harm.

"There is a moment now unlike any other moment that I've lived through, unlike any other I think that most of you have lived through," Cash said. "And part of that has to go hand-in-hand with environmental justice and equity. If you look at how our current system is … Black children have asthma rates that are twice as high as white children. Two-thirds of fossil fuel plants in the country are located in low-income and Black and brown communities. That's how the fossil fuel system has been set up, and it's partly due to agencies like mine, EPA, [which have] permitted those fossil fuel facilities for the last five decades."

Transmission Planning

With clean energy projects making up the vast majority of New England's interconnection queue, "we have to go from a reliability-driven planning process to a clean energy integration process, where transmission is used to reduce total costs, not just add costs," said Johannes Pfeifenberger, a principal at the Brattle Group. He said that transmission could cut customer rates by reducing generation integration costs and bringing cheaper resources to the grid.

On interconnection, Pfeifenberger said that New England is in a better place than most of the country but said that more needs to be done to meet the region's ambitious clean energy standards.

"Planning is so important: We should already know where we want to connect the 9 GW of offshore wind that are already committed to by the states; we should know where we interconnect the next 20 GW of wind; we should

NECPUC 75th Annual Symposium

know how to get 5 GW of onshore wind from Northern Maine to the rest of New England," Pfeifenberger said.

Pfeifenberger cited the "connect and manage" interconnection process used by Texas and the U.K., where projects are connected to the grid quicker — potentially reducing the interconnection process by several years — but face increased risks of curtailment and congestion.

"We don't have any congestion on the grid right now," Pfeifenberger said. "That tells us we can put a lot more energy on it. We want to accept some congestion, as it's cost effective."

Robert Ethier, vice president of system planning at ISO-NE, responded that "interconnecting people as quickly as possible comes with its consequences," saying it is important to ensure that the grid can handle additional resources.

"Just getting people interconnected is not the only metric we need to worry about," Ethier said. "There's a balance that needs to be struck there."

Ethier highlighted the potential of grouping projects together in areas with lots of interconnection to help speed up the process, as well as moving from a first-come, first-served process to a first-ready, first-served process.

Using Federal Funding

Speakers throughout the conference emphasized the importance of states making the most of the federal funds available through the Inflation Reduction Act and the Infrastructure Investment and Jobs Act.

Cash noted that EPA has about $100 billion to distribute to states, communities and companies for climate investments and programs. He said that while state utility regulators will not receive this funding themselves, they will play an essential role in "creating the regulatory landscape — the rules — that will allow that federal funding to be doubled, tripled, or quadrupled [by] private sector investment."

U.S. Sen. Peter Welch (D-Vt.) | © *RTO Insider LLC*

Hank Webster, deputy commissioner for energy at the Connecticut Department of Energy and Environmental Protection, highlighted the $1.25 billion hydrogen hub application submitted by a coalition of Northeast states, companies, and organizations as a means to address winter grid reliability. (See *Vermont Joins Northeast Clean Hydrogen Hub*.)

"That's a really exciting opportunity to take a big step forward," Webster said. "These are all generational investments that are necessary and are going to transform our energy systems."

Webster also spoke about some of the difficulties that states are facing in obtaining the new federal funding.

"Some of the challenges that we have are quick turnarounds between the notice of funding availability to when applications have to be in and all that, particularly on some of the bigger items like transmission planning," Webster said.

Webster added that figuring out how to limit impacts of supply chain costs, high interest rates, and geopolitical risks will be essential for making the most of the funding. He also advocated for additional flexibility on the income eligibility requirements on some of the funding opportunities, saying that states should be allowed to use more granular population data when available. ■

NECPUC 75th Annual Symposium

Energy Leaders Debate the Future of New England's Gas System

By Jon Lamson

STOWE, Vt. — New England must cut its natural gas use to meet the region's decarbonization goals, panelists said at the New England Conference of Public Utilities Commissioners (NECPUC) 75th Symposium last week.

But there was no consensus on how fast the fuel should be phased out or whether its infrastructure should be repurposed.

The gas network is one of the largest sources of carbon pollution in the region. The Massachusetts Department of Environmental Protection estimates that natural gas accounts for *nearly 40%* of the state's emissions from fuel combustion, an estimate that *likely undercounts* actual emissions by a significant margin because of unmonitored leaks from gas infrastructure.

Natural gas is used to heat *about 51%* of homes in the state and is also the largest source of electricity generation in New England, accounting for *about 52%* of the region's generation.

"The natural gas infrastructure is viable and necessary," said José Costa, the CEO of the Northeast Gas Association, which represents the region's gas utilities. "We should push back on those that want to phase out the infrastructure."

Costa said that he opposes efforts to ban gas hookups in new buildings, a movement that has been gaining steam in Massachusetts, which authorized 10 municipalities to implement gas bans for most new building construction during the state's previous legislative session.

"You should have choice there," Costa said.

Mackay Miller, a partner at consultant *ERM* and the former director of U.S. strategy at National Grid, disagreed with Costa, saying that states with mandatory emissions reductions targets should ban new gas interconnections. "By 2030 approximately, there should be ratepayer protections in place; there should be exemptions for critical facilities and other potentially industrial commercial customers where there's no comparable substitute service," he said.

"Every country that is on track for net zero has taken this step already — the U.K.; Netherlands — this would not be a huge deal."

Costa acknowledged that natural gas use must decrease to meet decarbonization targets but argued that it could be replaced with alternative fuels such as renewable natural gas and hydrogen.

Priya Gandbhir, a senior attorney at the Conservation Law Foundation, pushed back on Costa's characterization of those potential alternatives to natural gas, and said that decommissioning the bulk of the gas system makes the most sense for ratepayers and the environment.

"The evidence just isn't there that these alternative fuels, hydrogen and biomethane, are up to snuff," Gandbhir said. "In most circumstances, electrification is more efficient, more cost effective, safer, and more viable."

Gandbhir said regulators should be "reviewing and prohibiting utility propaganda about the purported benefits of alternative fuels such as renewable natural gas and hydrogen."

Mark LeBel, a senior associate at the Regulatory Assistance Project, said that accurately assessing emissions associated with the lifecycle of natural gas and alternative fuels will be an important step going forward.

"The leakage in the distribution system, in the transmission system, gas extraction — all that impacts the planet. So, I think at some point we're going to have to wrestle with some of those questions that we've been putting off in some of our environmental regulations," LeBel said. "When you burn the hydrogen, zero GHG emissions come from the point source. But the question is, where do you get the hydrogen from?"

Miller said that a focus on equity will be important in considering how to decarbonize the system while maintaining its safety, to ensure that cost burdens do not fall on low-income customers.

New England states that have pursued expedited pipeline replacement programs are facing a tension between the mounting costs of these programs and the risks that the infrastructure could become stranded assets as states move away from natural gas.

Miller said that regulators for states with newer, less leak-prone infrastructure "can probably accelerate depreciation or take some other fairly plain vanilla regulatory steps such that by the time you're at relatively low demand, you're still within the bounds of affordability."

For states with older, deteriorating gas systems, he said that regulators are facing a larger task to maintain affordability.

"There you would likely need to be looking at ways to offer capital investment opportunities to utilities that are not going to build up rate base. You need to be looking at ways to bring in other sources of funding to handle the capital expenditure," Miller said. "We've been hearing that there's some interest at the Department of Energy in supporting some of these safety-related pipeline expenditures. That would provide an interesting opportunity for a bit of a safety release valve on ratepayer bill pressure." ■

From left: Priya Gandbhir, Conservation Law Foundation; Mackay Miller, ERM; Northeast Gas Association CEO José Costa; and Mark LeBel, Regulatory Assistance Project | *© RTO Insider LLC*

ISO-NE News

1st Substations Set Sail for 1st US Offshore Wind Projects

Massive Gear to Equip South Fork, Vineyard Wind 1

By John Cropley

Transport ships set sail nearly simultaneously last week from Denmark and Texas to the New England coast, carrying the first substations to the first large-scale U.S. offshore wind projects.

A 1,500-ton substation built by Kiewit Offshore Services in Texas was loaded and departed Wednesday for the *South Fork Wind* project south of Rhode Island, which will feed up to 132 MW into the New York grid. It is the first U.S.-built offshore wind substation.

Meanwhile, Bladt Industries inched a 3,200-ton behemoth out of its production facility on the Denmark coast, down an access road and onto a waiting heavy-lift vessel (HLV). It set sail Wednesday for the *Vineyard Wind 1* project off Massachusetts, which will feed up to 800 MW into the New England grid.

The Vineyard substation's 2,000-ton, four-pile jacket foundation is making the journey as well, secured to the deck behind the substation.

South Fork and Vineyard both began construction last year and are expected to start generating power this year.

One of them will have the distinction of being the first utility-scale offshore wind farm to come online in U.S. waters, where the offshore wind sector now consists of seven turbines rated at a combined 42 MW.

Other nations have been building offshore wind farms for a third of a century, and installed capacity worldwide has surpassed 63 GW as the industry has matured. As a result, initial U.S. offshore wind development will rely to a significant degree on foreign equipment while a domestic supply chain is created and expanded.

A 3,200-ton substation is moved out of the Bladt Industries factory in Denmark and onto a ship Thursday for transport to the Vineyard Wind 1 offshore wind project in Massachusetts. | *Bladt Industries*

ISO-NE News

Nascent Industry

For this reason, design and fabrication of the South Fork substation in the U.S. is a milestone, developers Ørsted and Eversource Energy said in a *news release* Thursday.

"South Fork Wind continues to demonstrate the enormous power of offshore wind to create a new, American-based supply chain as we work to grow the clean energy industry here in the United States — spreading economic opportunity to workers and local communities across the nation," said Mike Ausere, vice president of business development at Eversource.

Also in Texas, Dominion Energy is building the first U.S. wind turbine *installation vessel*, and Ørsted and Eversource will be the first to charter it after its expected completion next year.

The supply chain for this new class of U.S. ship spreads far and wide.

The *Eco Edison*, the first service-operations vessel being built in the U.S., is using components made in 34 states, according to Ørsted and Eversource, which will use it for their Revolution, South Fork and Sunrise wind projects. The 262-foot ship will be the home at sea for up to 60 offshore wind technicians, the first group of whom are being trained now by Ørsted, the Danish firm that is the world's leading offshore wind developer.

Mature Industry

Denmark has become home to a mature offshore wind industry since the world's first offshore wind farm went online there in 1991.

Among the companies in the sector is Bladt, which has produced more than 3,100 foundations and 25 substations. For the Vineyard project, it partnered with two other Danish firms, Semco Maritime and ISC Consulting Engineers: Bladt worked on steel manufacturing, Semco and ISC on design, and Semco on

The first U.S.-built offshore wind substation is prepared for transport Wednesday from Ingleside, Texas, to the South Fork Wind Project off the Rhode Island coast. | *Ørsted and Eversource*

electrical installation.

Bladt said it and Semco have been targeting the new U.S. offshore market and secured seven of the first 11 substation contracts awarded in U.S. waters. When the substation and its foundation arrive at the installation site south of Martha's Vineyard, Vineyard Wind contractors will install it, and then Semco and Bladt will work over the summer to commission it.

In a *news release* Thursday, Bladt Chief Project Officer Klaus Munck Rasmussen said, "Many years ago, we were a part of the first offshore wind projects in Denmark when the industry evolved here, and it feels great adding a new chapter to our story with our involvement in the first U.S. project."

"Moving a 3,200-ton object is not something that we experience every day, so we have been excited to follow both load-out and sail-away from our side of the Atlantic," Vineyard Wind CEO Klaus S. Moeller said. "With the components on their way, we look forward to welcoming the barge here in Massachusetts."

Also Wednesday, a Portuguese-flagged HLV *docked* in New Bedford, Mass., bearing the first supersized components for the 62 towers that will be erected for Vineyard.

New Bedford years ago moved to *make itself* a shoreline hub for the wind industry envisioned off the New England coast.

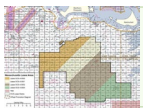
There is a little irony in this: A fleet based in New Bedford helped hunt some whale species nearly to extinction, harvesting their oil for lamp light. Now construction crews will sail out of New Bedford to create a new source of electricity to light homes and businesses. They are strictly mandated to take a long list of precautions to not kill any whales in the process.

New Bedford Mayor Jon Mitchell on Thursday called the landmark delivery of tower components "poetic." ■

National/Federal news from our other channels

GE to Assemble Key Onshore Wind Components in NY

Lawsuit Against Vineyard Wind over Threat to Whales Tossed



Eversource Begins Its Exit from OSW Development

RTO Insider subscribers have access to two stories each monthly from *NetZero* and *ERO Insider*.

MISO News

MISO: Little Firm Capacity to Spare this Summer

RTO Projects 'Sufficient Firm Resources'; Can Declare Emergencies to Access More

By Amanda Durish Cook

CARMEL, Ind. — MISO last week said it will likely have little firm generating capacity to spare in managing typical summertime peaks this year.

John Harmon, director of market administration, said during a Reliability Subcommittee meeting May 23 that the RTO is "continuing a trend where it increasingly relies on emergency resources, primarily in the form of load-modifying resources, and imports to manage peak loads."

He added that MISO could exhaust both its firm resources stack and emergency supplies if it encounters high outages and load in June and July. In August, a high-load, high-outage scenario would leave the grid operator with a slim 500 MW of emergency resources.

MISO *expects* to have 115 GW of accredited resources in June, 123 GW in July and 121 GW in August to meet respective peak loads of 115 GW, 123 GW and 120 GW. The grid operator projects "sufficient firm resources" to cover the summer forecasts. However, if it falls short of meeting demand even under typical conditions, it can declare emergencies so it can access more than 11 GW of emergency padding from load-modifying resources.

MISO normally experiences a little more than 15 GW in forced generation outages and nearly 22 GW in total outages during the summer months.

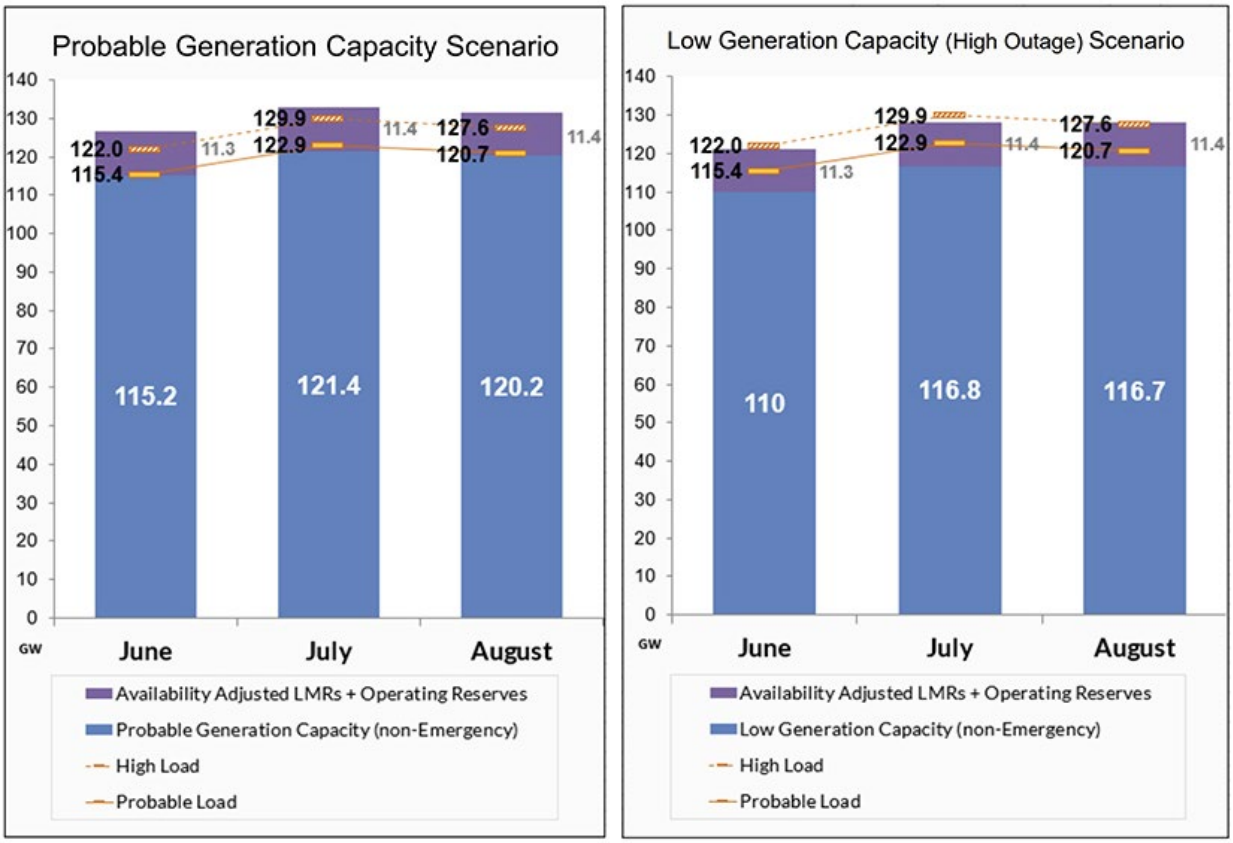
Staff released the seasonal resource assessment later than usual this year because the delayed planning resource auction slowed the availability of capacity data. All MISO zones met their margin requirements for the 2023/24 planning year, which begins June 1. (See *1st MISO Seasonal Auctions Yield Adequate Supply, Low Prices* and *MISO Summer Assessment Postponed for Auction Results*.)

The spring months have been uneventful so far. MISO *averaged* a 71-GW systemwide load in March, peaking at 89 GW on March 20. Natural gas accounted for the biggest slice (38%) of the fuel mix, followed by coal (24%), wind (19%) and nuclear (15%). Average real-time prices fell from $42/MWh last March to $26/MWh.

The RTO called for conservative operations — requesting deferred maintenance on facilities so they could be returned to service — in Indiana, Kentucky and Illinois after an outbreak of tornados and high winds March 31-April 1. It also issued a footprint-wide severe weather alert April 4-5 as a swath of severe thunderstorms moved across the country.

Besides those exceptions, Harmon said, the system "performed as expected." Load averaged 66 GW during the *month*, with a 78-GW peak April 4. The month's real-time prices dropped from a $60/MWh average last year to $26/MWh. April's fuel mix was natural gas (36%), wind (23%), coal (21%) and nuclear (16%).

MISO recorded an all-time solar generation peak of 2.7 GW on May 4. ■



MISO's summer resource adequacy projections | *MISO*

MISO News

MISO to Evaluate System Attributes Through Year-end

By Amanda Durish Cook

CARMEL, Ind. — MISO says it will wait until the end of the year to determine how it measures and encourages the six generating attributes it says are necessary to its system operations.

The system reliability attributes include availability, delivering long-duration energy at a high output, rapid start up times, providing voltage stability, ramp-up capability and fuel assurance. (See *MISO Considers Resource Attributes as Thermal Output Falls*.)

During a Resource Adequacy Subcommittee meeting Wednesday, MISO Director of Policy Studies Jordan Bakke said staff need to tap the RTO's resources to strengthen system health as the resource transition exposes reliability hazards. He added that there's no one "perfect resource" or small group of resources that can furnish a flawless balance of reliability, flexibility and affordability.

Bakke said earlier this year that MISO's attribute discussions could prompt "fundamental changes" in how it operates the markets and ensures reliability. He said staff think it will take several years to roll out solutions in the most "equitable" way they can.

Bakke said MISO believes that the six attributes will become increasingly scarce in coming years. He said their rate of disappearance will help determine whether "new and adaptive market products, new participation requirements or just plain more visibility" are needed.

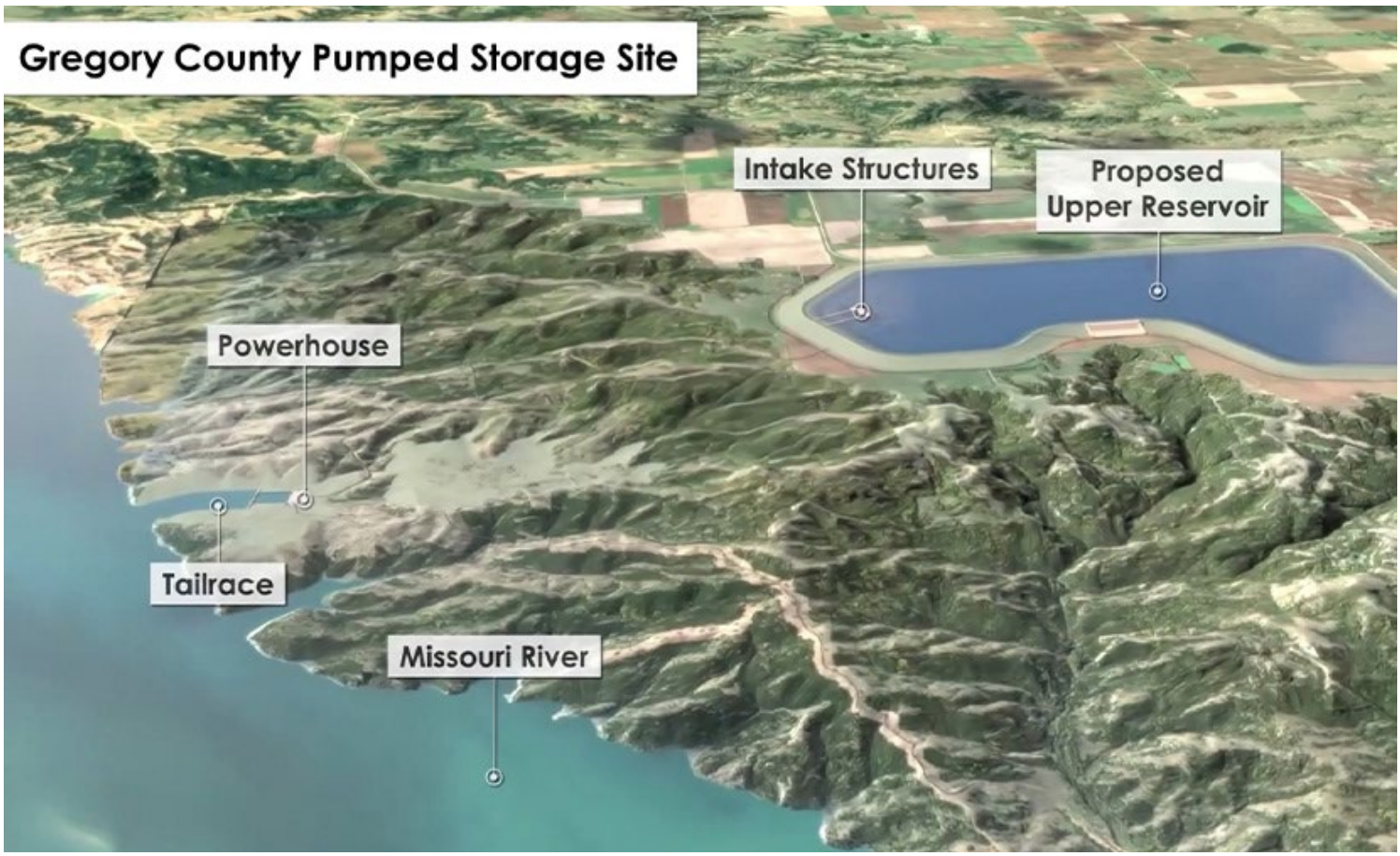
Renewable resources may account for as much as 40% of the fuel mix in the 2027-2028 time frame, he said, "relatively sooner than we thought where we were going to be five years ago."

Minnesota Public Utilities Commission staffer Hwikwon Ham said decisions on cultivating the attributes need to happen urgently given that Missouri River Energy Services and MidAmerican Energy *announced* that week that they're scrapping a planned pumped hydro storage project in central South Dakota over financial concerns. The Gregory County Pumped Storage Project would have stored output from MidAmerican's wind fleet. MidAmerican Energy and MRES said they will "continue to evaluate all options," including pumped storage.

Independent Market Monitor David Patton has called MISO's attempt to single out and quantify necessary system attributes "somewhat misguided," saying that recognizing attributes as discrete is problematic. He said the grid operator should instead pursue an accreditation method that values a generator's usefulness to the grid.

"I don't think you can model these things. Nobody can," Patton said during an RASC meeting in April.

Bakke said that while an accreditation more representative of generation output is necessary, there is still much to be done in ensuring resource adequacy. ■



Missouri River Energy Services and MidAmerican Energy abandoned plans last week for the Gregory County Pumped Storage Project in South Dakota. | *Gregory County Pumped Storage Project*

MISO News

MISO: Sloped Demand Curve Would Have Raised 2023/24 Capacity Prices

By Amanda Durish Cook

CARMEL, Ind. — MISO said Wednesday that a sloped demand curve applied to its recent seasonal auction would have boosted summer clearing prices as much as sixfold, better reflecting the footprint's tapering supply.

Staff said their internal analyses showed that a seasonal systemwide sloped demand curve would have cleared the Midwest region at $65.50/MW-day in the summer, $25.90/MW-day in the fall, $5/MW-day in the winter and $19.10/MW-day in the spring. MISO South would have cleared at $25.70/MW-day (summer), $25.90/MW-day (fall), $5/MW-day (winter) and $19.10/MW-day (spring).

The subregional transfer constraint between the South and Midwest would have bound and resulted in price separation for the summer season, MISO said.

The RTO is on a mission to design and implement downward-sloping demand curves by its 2025/26 capacity auctions. It's aiming to have a FERC filing ready sometime in the third quarter. (See *MISO Charts Course on Capacity Auction's Sloped Demand Curve*.)

The grid operator said the 2023/24 auction would have cleared 137.7 GW systemwide for the summer with a sloped demand curve, 3.6% beyond its 132.9-GW planning reserve margin requirement. In other seasons, the auction cleared 0.8% above the PRM requirement (spring and fall) and 2% (winter).

The 2023/24 planning resource auction cleared most of its subregions at $10/MW-day (summer), $15/MW-day (fall), $2/MW-day (winter) and $10/MW-day (spring). (See *1st MISO Seasonal Auctions Yield Adequate Supply, Low Prices*.)

During a Resource Adequacy Subcommittee meeting Wednesday, MISO's Mike Robinson said that the nearly 4.7 GW in excess capacity from this year's auction in MISO Midwest does have incremental value, though the current vertical demand curve has no way to appraise it.

"Prices have crashed because we're a little long. Prices have gone from the highest price possible last year to $10/MW-day this year," he told stakeholders.

MISO said its current capacity auction design "does not facilitate the investment and retirement decisions necessary to maintain the resources to meet system reliability."

The grid operator intends to base its sloping demand curves on separate seasonal reliability targets for the Midwest and South auctions. Its analyses have only shown an incremental capacity value for capacity procured beyond the season's reliability target in summer. Robinson said the summer value is a "reflection of assignment of risk."

To formulate sloped demand curves, MISO will run studies using the net cost of new entry (CONE), or an approximated revenue requirement from capacity payments. To do this, MISO is using three years of historical data to calculate inframarginal rents that cover generators' fixed costs. Net CONE is calculated by subtracting inframarginal rents from CONE and will be used to influence the curves' final shape.

MISO said the Midwest's net CONE averages $73,200/year (about 71% of CONE) and the South averages $58,500/year (about 62% of CONE).

Robinson said staff are hoping to lock in the demand curves' shape for three to four years at a time, periodically re-evaluating them to reflect the changing resource mix.

"Can we set up an auction design where asset owners can cover their costs?" Robinson asked hypothetically. "But we don't want to over-procure. We want to do this judiciously."

Bill Booth, a consultant to the Mississippi Public Service Commission, said the auction has little financial impact on vertically integrated utilities. He said bilateral contracts are a better measure of capacity value.

"Don't think that these signals are going to stop someone who wants to retire a coal plant from retiring it," Booth said.

Michelle Bloodworth, CEO of coal trade group America's Power, argued that increased revenues in MISO's auction might make a difference to owners of existing thermal plants.

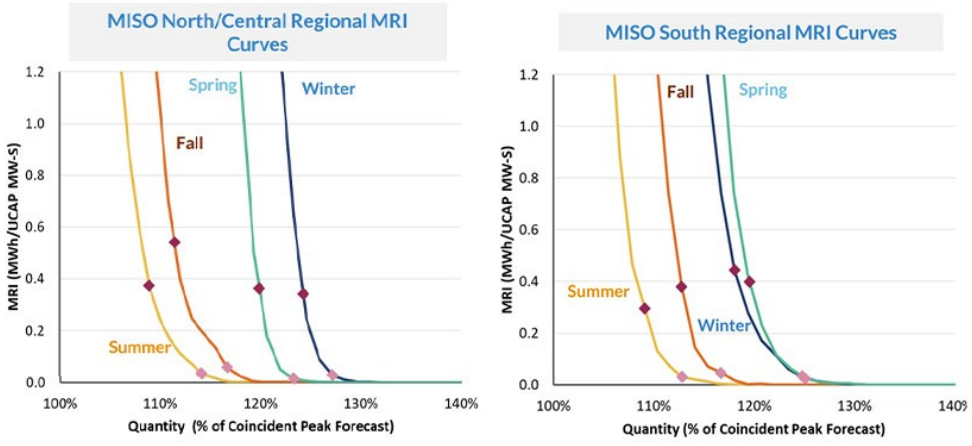
"We do believe that the auction results reflect this year. However, the long-term trend of depleting resources continues to play out," Durgesh Manjure, MISO's senior director of resource adequacy, said.

Manjure said that by dividing capacity procurement into seasons this year, MISO spread risky times into separate seasons and lowered PRM requirements. He said this year's annual requirement was 7.4% on an unforced capacity basis, compared to 8.7% last year.

The RTO is also proposing to include an opt-out provision from the sloped demand curve for market participants.

Robinson said that while MISO is "trying to craft more reasonable" auction outcomes to reflect excess capacity's incremental value, it also must respect states' rights to resource adequacy.

MISO plans to require load-serving entities opting out of the curve to meet a capacity requirement that relies on the PRM requirement plus an additional, yet-to-be-determined percentage likely ranging from 1.5 to 3%. The RTO has proposed that LSEs opting out of the curve do so for three years at a time. ■



Draft sloped demand curves by season between MISO Midwest and MISO South. The diamonds on the lines represent the range at which MISO expects auction prices to clear. | *MISO*

MISO News

MISO, SPP Staffs Take Crack at Rate Pancaking

MISO's Long-term Transmission Planning will Delay Staff Work on Measure

By Tom Kleckner

SPP staff told stakeholders Friday they will work with MISO staff to draft a white paper on rate pancaking and unreserved use, two issues that bedevil utilities along the RTOs' seam.

Clint Savoy, SPP's manager of interregional strategy and engagement, told participants during the RTOs' spring update on common seams initiatives that the focus will be rate pancaking. He said while the two issues are separate and distinct, rate pancaking "is more of an issue that occurs."

The RTOs' staff will work with stakeholders and solicit their input in developing solutions, Savoy said. SPP will also use Seams Advisory Group as a sounding board in determining the paper's final draft. Later work will involve analyzing the proposals to determine their impact.

MISO's Marc Keyser, director of seams coordination, membership services and customer coordination, said his staff will be slow to join the effort, given their work with the grid operator's long-term transmission planning.

"We may have difficulty doing some of the analysis we want to do with the white paper, but we're looking forward to working with SPP," he said.

A working group composed of state regulators from the grid operators' footprints was the most recent stakeholder group to look at rate pancaking, which occurs when power is scheduled across more than one transmission provider's borders and each provider assesses full or partial charges for use of the facilities. That leads to duplicate transmission fees between the various providers.

MISO, SPP are taking a look at pancaked transmission rates. | *GridLiance*

Arkansas Electric Cooperative Corp. (AECC) said during a presentation to the group that it has incurred about $100 million in incremental costs over the past 10 years because of pancaked rates. AECC is connected to four transmission systems within the two RTOs.

Unreserved use charges can be assessed when an RTO transmission customer does not reserve adequate service to cover its load obligation. These charges are higher than the cost of reserving transmission and can have a ratcheting effect that transmission customers see as punitive.

The RTOs are currently involved in a dozen seams initiative between themselves and with stakeholders, both at the state and federal level. Their staffs will hold another update on seams initiatives in November. ■

NYISO News

NYISO MMU Calls for Improved Shortage Pricing, More Capacity Zones

ISO Already Pursuing Three of Five High-priority Recommendations

By John Norris and Rich Heidorn Jr.

NYISO needs to improve shortage pricing and create smaller capacity zones, the ISO's market monitoring unit (MMU) said in its 2022 State of the Market *report*.

MMU Potomac Economics, which *presented* its findings at Thursday's Installed Capacity/Market Issues Working Group (ICAP/MIWG) meeting, reported that the ISO remained competitive in 2022 but said changes are needed to ensure market efficiency as renewable penetration increases.

The report includes five high-priority recommendations, three of which — modeling local reserve requirements in New York City load pockets, dynamically adjusting operating reserve requirements, and improving capacity modeling and accreditation (Recommendations #2017-1, 2015-16 and 2021-4) — are already being pursued.

Also on the high-priority list are a recommendation from 2017 to modify operating reserve demand curves to improve shortage pricing (#2017-2) and one new recommendation: to create more "granular" locations in the capacity market (#2022-4).

The MMU found that NYISO's shortage pricing has fallen well below that of neighbors PJM and ISO-NE. "When there is an imbalance between the market incentives provided in two adjacent regions, it can lead market participants to schedule interchange from the area with weaker incentives to the area with stronger incentives even when the area with weaker incentives is in a less reliable state," the MMU said.

Four Capacity Zones Not Enough

The MMU said the ISO's current four capacity zones (New York City, Long Island, Lower Hudson Valley and Rest-of-State) are too large to provide efficient locational price signals to incent new flexible generation and encourage the retirement of less valuable resources.

The state's four zones do not account for transmission limits within the zones, meaning resources at some locations are over- or under-compensated relative to their reliability value, the MMU said.

It recommended the ISO create and "dynamically update" an increased number of capacity zones reflecting the known transmission constraints, saying the change also would address "concerns that the current deliverability framework is an inefficient barrier to investment in new resources."

It said the ISO should not use its existing capacity zone creation process, which it called "flawed and ineffective."

Potomac said the ISO's method for determining local capacity requirements (LCRs) results in inefficient prices across zones and excessive price volatility.

Instead, it said the ISO should consider basing locational pricing on marginal reliability values instead of the current zonal demand curves. "This could result in sizeable reliability and economic benefits over the long term and simplify the administration of the capacity market," it said.

In the 2023/24 capability year, the MMU said, large resources and "Special Case" demand response resources in New York City will receive as much as $52 million in excess capacity revenue.

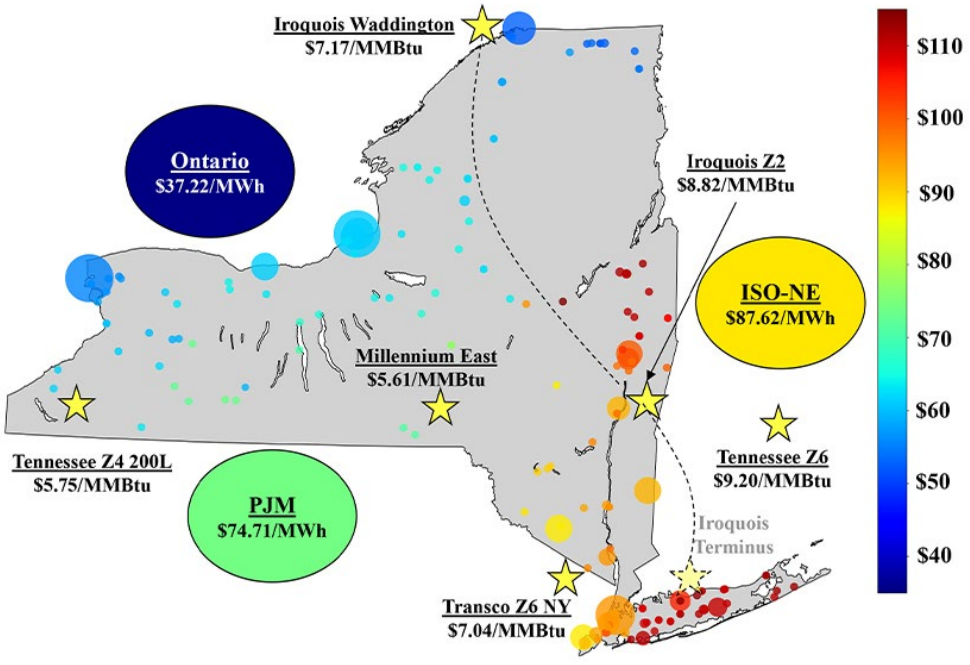
Some fossil fuel and nuclear generators also were overpaid because the ISO included in their installed capacity 1,200 MW that was "functionally unavailable" on the hottest days last summer, Potomac said. "This includes resources with emergency capacity that is virtually never committed in practice, resources with ambient water and air humidity dependencies that are not captured in the [dependable net maximum capability] testing process, and cogeneration units that face limitations associated with their steam host demand."

The MMU reiterated a recommendation from its 2021 report that the ISO improve its resource adequacy model (#2021-4) and added a new proposal: that it compensate capacity suppliers based on their contribution to transmission security when LCRs are set by transmission security needs (#2022-1).

Deliverability Testing

Potomac also highlighted what it called a misalignment of the ISO's deliverability framework, which it said "unreasonably inhibits new investment."

It noted that the recently completed Class Year 2021 study initially allocated $1.5 billion in system deliverability upgrade costs to 4 GW of new projects seeking to sell capacity — costs that equaled between 50% and 293% of the



New York energy and transmission congestion patterns in 2022 | *Potomac Economics*

NYISO News

net cost of new entry of a new peaking plant. "Unsurprisingly, three-quarters of the affected projects refused to pay these costs and either withdrew from the Class Year or accepted a reduced quantity of [capacity resource interconnection service] rights," Potomac said.

Current ISO rules use a deterministic test "that often does not represent a realistic or likely dispatch of the system during conditions when reliability is threatened," Potomac said. "This problem is exacerbated by performing the test in relatively large capacity zones with many potential intrazonal constraints."

In the short term, the MMU said, the ISO should identify "a comprehensive set of granular locations" that would effectively shrink the size of the capacity zone in which new interconnecting resources would have to be deliverable. The change also would allow reduced clearing prices in export-constrained areas, it said.

Seasonal Capacity Market

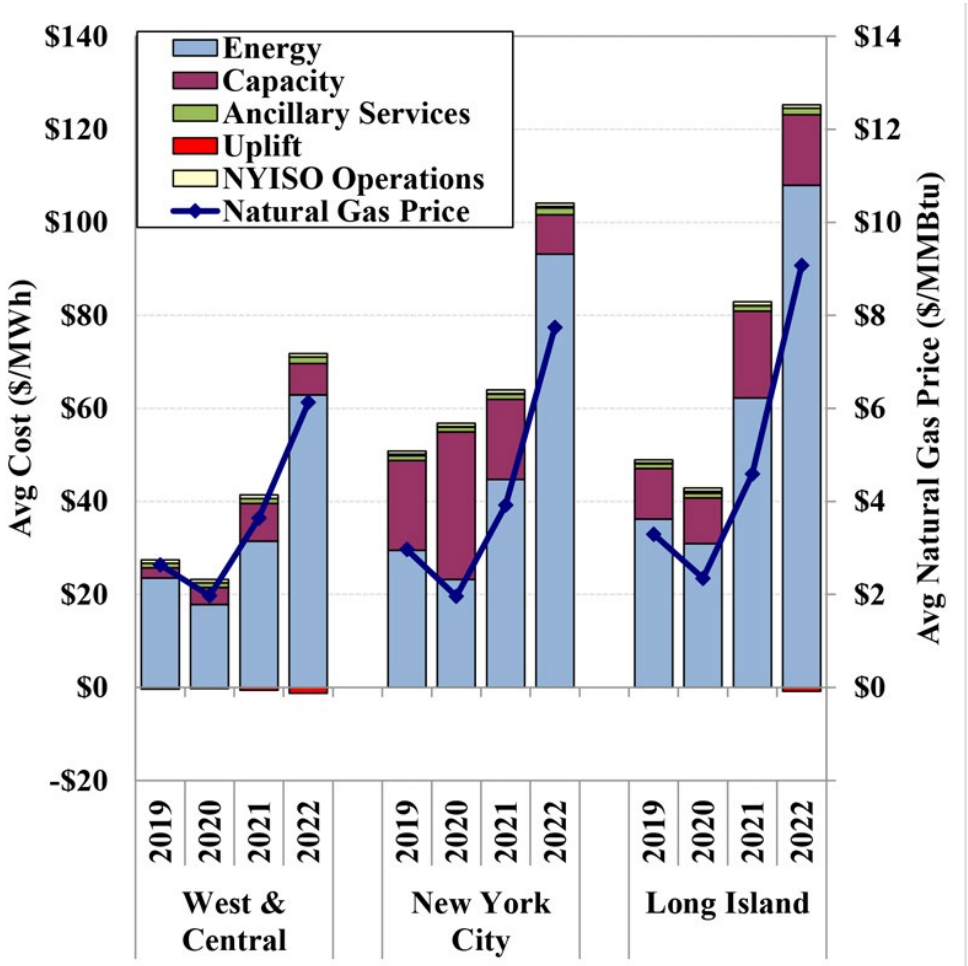
The MMU also recommended the ISO move to a seasonal capacity market, with requirements and demand curves that consider the reliability needs of each season separately (#2022-2). Although the capacity market is divided into six-month summer and winter capability periods, the installed reserve margin and LCRs are determined annually, so ICAP requirements are the same in all months. "As a result, seasonal prices are determined by the amount of ICAP available in each season, which bears little relation to resource adequacy risk," Potomac said.

Transmission Planning

The MMU also offered a new recommendation on transmission planning, saying current rules allow inefficient projects to crowd out competing market-based investments — including transmission and nontransmission resources — that could achieve the same policy goals at lower cost.

Potomac acknowledged the ISO's recent addition of capacity expansion modeling tools. But it said additional changes are needed to respond to the increased uncertainty from the growth of policy-sponsored resources.

It recommended the ISO update its planning study methodology to reflect the market incentives of renewable and storage resources; consider changes to the resource mix resulting from the inclusion of economic and public policy projects; and estimate transmission project benefits based on their market value to the ISO (#2022-3).



Average all-in price by New York region | *Potomac Economics*

The MMU's report was discussed with stakeholders for the first time at the ICAP/MIWG meeting, where the focus was on energy and ancillary services. Potomac will present the report to the Management Committee meeting and discuss capacity market issues at the next ICAP/MIWG meeting, June 6.

Other Recommendations

Potomac's Pallas LeeVanSchaick, who presented the findings at the May 25 meeting, said the efficiency of the energy and ancillary services markets will become increasingly important as NYISO increasingly shifts from fuel-secure generation to intermittent renewables.

The report cited inefficiencies for reserve providers, which are not being compensated for their congestion relief; duct-firing combed cycle units, which are not being properly dispatched; and phase angle regulators, which are inappropriately being used to satisfy bilateral contract flows.

In addition to the high priority recommendations, LeeVanSchaick also highlighted five other proposals during Thursday's meeting.

- 2015-9: Eliminate transaction fees for coordinated transaction scheduling at the PJM-NYISO border.
- 2016-1: Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief.
- 2020-1: Consider enhancements to the scheduling of duct-firing capacity in the real-time market that more appropriately reflect its operational characteristics.
- 2021-2: Model full locational reserve requirements for Long Island.
- 2022-3: Improve transmission planning assumptions and metrics to better identify and fund economically efficient transmission projects.

Market Highlights

Potomac reported that average natural gas prices roughly doubled from last year in eastern New York and rose 70% in the western

NYISO News

part of the state because of increased LNG exports and cold weather.

The high gas prices drove energy prices, with average energy prices in Western New York rising to 109% over 2021 and Eastern New York rising as much as 126%. Gas prices, cold weather and transmission congestion pushed all-in energy prices to the highest levels observed in more than a decade, ranging from $58/MWh in the North Zone to nearly $127/MWh in Long Island.

More severe transmission congestion in the Central-East interface becuse of lengthy outages during construction of the AC Public Policy Transmission Projects contributed to the East-West price separation.

Capacity costs fell, primarily because of changes in the installed reserve margin for the system and LCR requirements for New York zones.

Winter Storm Elliott

Another highlight from Potomac's annual report was the analysis of Winter Storm Elliott's impact on the New York grid, which showed NYISO's market operations relied heavily on the scheduling of internal peaking units to meet high demands and that large quantities of generating capacity was unavailable because of fuel limits or outages.

Winter Storm Elliott hit the Northeast from Dec. 23 to Dec. 27, 2022, and blizzard conditions through the 24th caused New York energy prices to spike to more than $4,000/MWh.

LeeVanSchaick said the storm "was the first significant test for some market processes that have come into place over the past 10 years that deal with shortage conditions."

"This was the first time we've seen long-duration reserve shortages since PJM and ISO-NE put [Pay-for-Performance] rules in place," he added. PFP rules incentivize generators for being available during tight supply conditions.

On Dec. 23 and 24, NYISO experienced eight hours of reserve shortages, locational-based marginal prices of more than $2,000/MWh, roughly 4 GW of import curtailment and around 2.3 GW of unavailable fossil fuel capacity because of outages or derates.

Because the amount of forced outages and derated capacity was higher than anticipated, Potomac said NYISO needs to better monitor generator performance during extreme weather, given that current resource adequacy models may be underforecasting load during these cold conditions and inefficiently dispatching generators to provide reliability.

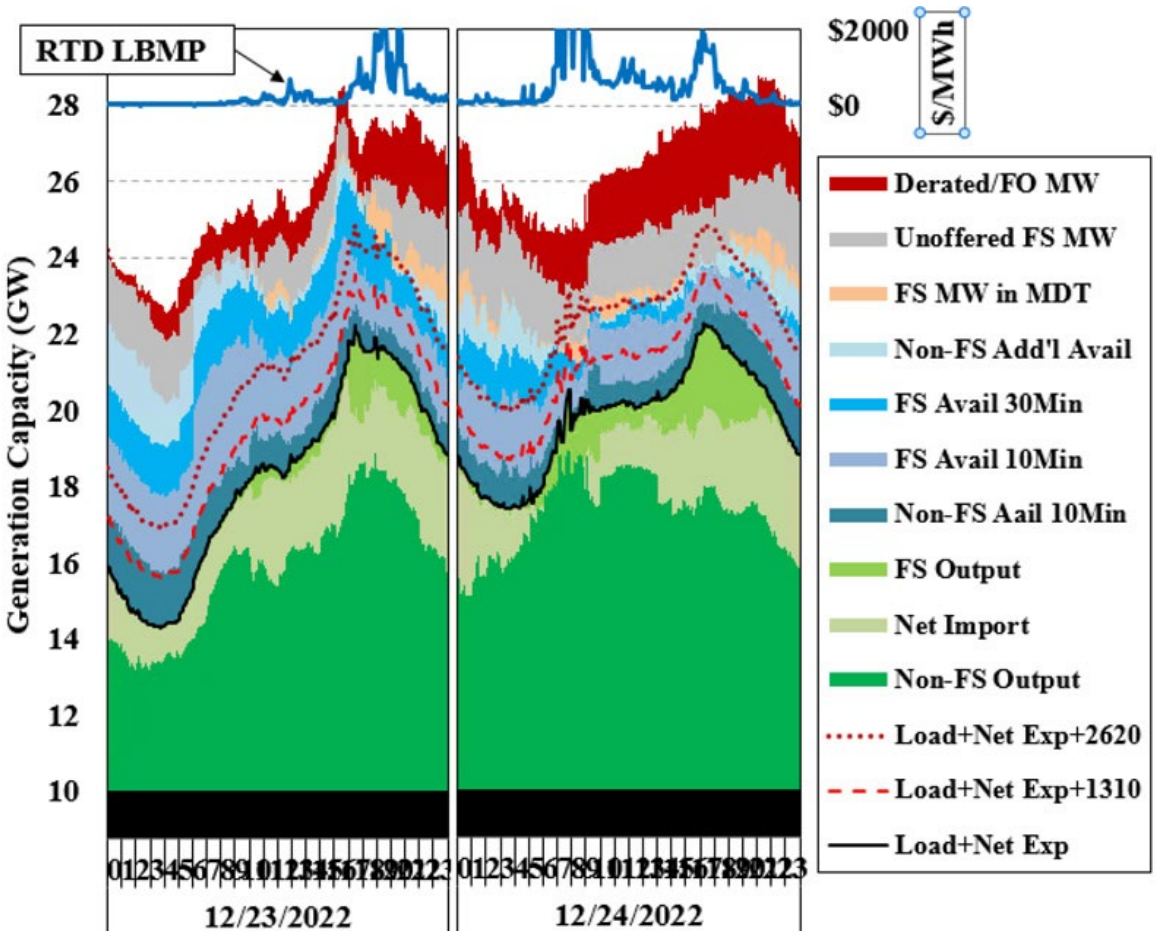
The report also noted that about 80% of unoffered capacity during the blizzard was from energy storage and other duration-limited resources. The MMU said NYISO needs to investigate ways to make sure that during cold conditions, these resources can recharge after being called upon and be available for extended periods of time.

Potomac said the ISO's real-time commitment scheduling was being undermined, citing the number of import curtailments and unforeseen reductions in supply availability, because of either high gas prices or inefficient market signals.

The MMU noted that several fast-start units were either being shut down or not started up when they might have otherwise, which meant 470 MW of these units was unavailable and an additional 1,350 MW of 30-minute fast-start capacity was sitting offline. This resulted in imports from neighbors like PJM to be curtailed because of unnecessarily high prices in New York.

Based on these findings, Potomac made several recommendations to improve NYISO's capabilities during future winter storms.

The MMU recommended setting prices consistent with the reliability risks during a reserve shortage event, enhancing capacity accreditation models for nonfirm fuel generators or duration-limited resources, and scheduling additional reserves before blizzard conditions to decrease the NYISO's reliance on imports. ■



Resource supply availability and utilization during Winter Storm Elliott | *Potomac Economics*

NYISO News

NYISO Business Issues Committee Briefs

Long Island PPTN

NYISO's Business Issues Committee (BIC) *voted* Wednesday to recommend that the Management Committee (MC) also votes to recommend that NYISO's board approve the draft Long Island Public Policy Transmission Needs (PPTN) report.

The draft report identified 16 viable projects that could unbottle Long Island's transmission constraints and enable the island to export offshore wind energy to the rest of New York. Propel NY's Alternative Solution 5 project (Project ID: T051) was ranked No. 1 because it would add a 345-kV backbone and help with the efficient transfer of power in the future. (See *NYISO Recommends NYPA-Transco Proposal for Long Island Tx Need*.)

Propel NY, a partnership between the New York Power Authority and NY Transco, would build the project along with the Long Island Power Authority and Consolidated Edison.

According to NYISO, this was the first PPTN evaluation cycle in which cost containments were explicitly required as part of a developer's proposal and a mechanism was included to evaluate and implement a transmission owner's right of first refusal for related upgrades on their system. (See "ROFR 'Upgrades' Clarification," *NYISO Management Committee Briefs: Nov. 30, 2022*.)

The report moves to the MC meeting where it will undergo a similar advisory vote this Wednesday. The Board of Directors will select the project to be built, and it will have a required in-service date of May 2030.

Manual Updates for DER

The BIC meeting also approved several updates to NYISO *manuals*, including changes to the revenue metering requirements manual, meter services entity manual, and the accounting and billing *manual*, which help enable distributed energy resource market participation.

NYISO confirmed that these approved revisions become effective at the same time as other DER tariff revisions accepted by FERC (*ER19-2276*).

Bilateral Transactions

BIC stakeholders voted to recommend that the MC approve NYISO *proposed* tariff revisions necessary to enable withdrawal-eligible generators, such as energy storage resources (ESRs), to be sinks for bilateral transactions. (See "Energy Market Projects," *NYISO Outlines Timelines for 2023 Projects*.)

The revisions will update current software capabilities to enable this functionality by the end of this year. ESRs can then contract with a specific generator for its energy, such as a wind farm, through a bilateral contract and enter directly into that agreement.

The proposal moves to the next MC for consideration.

FERC Compliance Filings

NYISO on May 23 informed the Installed Capacity Working Group/Market Issues Working Group (ICAP/MIWG) that it had submitted a third compliance filing for Order 2222 earlier that week to correct inconsistencies identified by FERC (*ER21-2460*).

The commission found several of NYISO's earlier tariff revisions, which relate to distributed energy resource aggregation market participation in New York, to be either redundant or noncompliant. (See *FERC Orders More Compliance Filings from NYISO for Order 2222*.)

NYISO also told ICAP/MIWG stakeholders that the ISO would begin working to implement a 17-year amortization period when calculating fossil fuel peaker plant capacity market metrics, after FERC approved the ISO's proposal this month. (See *FERC Accepts NYISO's 17-Year Amortization Period Proposal*.)

The ISO said it would submit demand curve compliance filings in early June and planned to use the 17-year period for July spot auctions, which run at the end of June. ■

— John Norris

A rooftop solar array in Poughkeepsie, N.Y. | *Lucas Braun, CC BY-SA 3.0, via Wikimedia Commons*

NYISO News

NY Moves to Boost Hydrogen Production and Development

Low-cost Electricity Allocated to Plug Power; Grants Offered to Researchers

By John Cropley

New York last week announced two efforts to help boost hydrogen as a means of reaching its emission-reduction goals.

The New York Power Authority will allocate an additional 50 MW of low-cost hydropower to fuel cell manufacturer Plug Power to boost production of green hydrogen at a facility it is building in western New York.

Meanwhile the New York State Energy Research and Development Authority will administer a $10 million solicitation for clean hydrogen research, development and demonstration projects in hard-to-electrify sectors.

Both initiatives are part of the larger effort to slash emissions of greenhouse gases in New York. Hydrogen's role in the drive to decarbonize is still being defined, as its potential as an economical and environmentally friendly fuel is still being developed.

Plug Power's award was announced Thursday. The company is based just north of the state capital but has been expanding geographically in recent years as its market and sales have grown.

It began production earlier this year at a new factory south of the capital and is building a hydrogen generation facility near NYPA's Niagara Power Project, which will supply the electricity announced Thursday. After starting construction of the western New York facility, the company expanded the plans, boosting the designed maximum output from 45 to 74 tons of liquid hydrogen per day.

NYPA sells inexpensive power to chosen businesses as a development tool; Plug receives 272 MW in total at its three existing in-state facilities. The state-owned utility's board of trustees also authorized it to procure 62 MW of high-load-factor power for Plug on the energy market.

NYSERDA's R&D solicitation announced Wednesday complements New York's effort with six other states to form the Northeast Regional Clean Hydrogen Hub.

As its name implies, that is a broad regional effort. The solicitation is more closely focused on problematic New York applications.

"In partnership with the state's leading innovators and problem-solvers, we are taking bold action to transition even the hardest-to-electrify sectors, helping secure a healthy and sustainable future for all New Yorkers," Gov. Kathy Hochul said in a news release.

Proposals are sought in four areas:

- hydrogen applications to decarbonize industrial process heat;
- clean hydrogen production and integration with renewable energy such as solar and offshore wind;
- mitigation of nitrogen oxides in hydrogen combustion; and
- hydrogen storage technologies, including bulk storage and storage in limited footprint areas.

Applicants for state funding must be based in New York and must also be actively seeking federal funding for their projects. Any state award will be contingent upon the project also being approved for federal funding.

NYSERDA will host a *webinar* June 7 on the *details* and requirements. The *application* deadline is June 28. ■

Plug Power's new production facility near Albany, N.Y., is shown in January 2023. | *New York Governors Office*

PJM News

PJM Board Rejects Lowering Capacity Performance Penalties

AMP Executive Disappointed, Says Company Won't Support Package Undermining Reliability

By Devin Leith-Yessian

The PJM Board of Managers last week rejected a stakeholder-endorsed proposal to lower the penalties for nonperformance in the RTO's capacity market but *said* it would propose to FERC to redefine when a performance assessment interval (PAI) can be triggered.

The *proposal* endorsed by the Members Committee on May 11 would have changed the formula for the penalty rate ($3,177/MWh) and stop loss ($142,952/MW-year) to be based on capacity auction clearing prices for the locational deliverability area (LDA) the resource is in, rather than resources' net cost of new entry (CONE). (See *PJM Members Committee Approves Performance Penalty Reduction*.)

It also included tightening the conditions under which PJM could declare a PAI, limiting when generators can be subject to performance charges.

In a letter to stakeholders, board Chair Mark Takahashi wrote that by only proposing changes to the PAI trigger, the RTO can align penalties with when generators' performance is critically needed while having the best chance of the proposal being accepted by FERC for implementation in the 2023/24 and 2024/25 delivery years.

"During the quick-fix process, PJM articulated concerns that the endorsed changes to the penalty rate and stop-loss may contribute to reliability concerns absent additional paradigm enhancements such as stricter winterization, testing and fuel security requirements, due to the reduced incentive for generators to respond in emergencies," Takahashi said.

Takahashi also noted that three letters had been written to the board arguing that the proposal would reduce the incentive for generators to perform during emergencies and potentially violated FERC's filed-rate doctrine. PJM staff agreed, he said, having raised concerns throughout the stakeholder process about lowering penalties without adding requirements for capacity resources with the aim of ensuring reliability.

PJM Board of Managers Chair Mark Takahashi speaks during the RTO's 2023 annual meeting on May 2. | © *RTO Insider LLC*

Stakeholder Reaction

Steve Lieberman, American Municipal Power's (AMP) vice president of transmission and regulatory affairs, told *RTO Insider* he was disappointed the board did not side with the majority of stakeholders in supporting the proposal and instead was swayed by unsubstantiated claims that it would harm reliability. AMP brought the proposal before the Markets and Reliability Committee, where it was endorsed May 4. (See *PJM MRC Endorses Proposal to Reduce Performance Penalties*.)

Lieberman said AMP would not support a package that undermined reliability and noted that PJM had indicated support for LS Power's *proposal*, which would have reduced the stop-loss limit to $24,659/MW-year. He said that is nearly as low as AMP's proposal, which contained a $17,744/MW-year stop loss.

The main difference between the proposals was that the LS Power package would have retained the status quo penalty rate derived from net CONE, while AMP would have shifted to basing it off the Base Residual Auction clearing price to yield a $394/MWh rate. By keeping a high rate and reducing the stop loss, Lieberman said the LS Power proposal posed a reliability risk by potentially clustering penalties in a small number of hours, which if reached would effectively exempt generators from penalties for the remainder of the delivery year.

"Imagine a generator during a Capacity Performance event July 1 and the generator fails to perform and it accumulates all these penalties if it reaches the stop loss limit. ... For the rest of the delivery year, if there's another capacity performance event, the generator would be more or less excused from any penalties," he said. Under the AMP proposal, reaching the stop loss would take about 45 hours of penalties, the same as the status quo, while under LS Power's package it would take about 7.5 hours, he said.

By focusing only on the penalty triggers,

PJM News

Lieberman said the board missed the problem the quick-fix issue charge was meant to address: aligning penalties with the revenues generators receive from the capacity market. Under the current rules, as much as two years worth of capacity market revenue could be lost because of penalties. While he said PJM will likely pursue penalty rate and stop-loss changes through the ongoing Critical Issues Fast Path process, he said that could take years to unfold, and more immediate changes are needed.

"The reason that we went down this path around a month ago is still unaddressed," he said. "It's very troubling that the board is ignoring the solution and willing to kick out a fix for years."

Marji Philips, senior vice president of wholesale market policy at LS Power, said the changes to the PAI triggers were necessary to avoid the "irrational and nontransparent" situations that arose during December 2022's Winter Storm Elliott, during which generators were subject to penalties while LMPs were low and PJM was exporting.

LS Power initially brought the issue charge and problem statement before stakeholders through the quick-fix process but revised it based on PJM feedback. AMP's proposal was LS Power's as originally issued.

"You need to align the pricing with what is needed operationally, and that's what this fix for the triggers will do," Philips said.

While she lauded the changes to the triggers, she said more work is needed to address imbalances between the penalties and capacity market revenues. "The stop loss really needs to be fixed so there's some balance between your capacity payment revenues."

"PJM did the right thing, and we're relieved to see such a swift response to such a reckless proposal," Tom Rutigliano, senior advocate at the Natural Resources Defense Council, said in a statement. "There should not be a public bailout of bad investment decisions, and we hope FERC takes the same tack on the questions before them now. There should be a clear message to industry that you must be able to keep the promises you are paid to keep."

Letters to the Board

In a *letter* to the board hours before Takahashi's letter was released May 23, several environmental groups urged the board to reject the MC-endorsed proposal, saying the CP construct had preserved reliability through Elliott and reducing its penalties would undermine PJM's markets and risk reliability as generators make decisions about how to prepare for next winter.

"In the coming months, generation owners and demand-side suppliers will make decisions on winter readiness preparations," the groups said. "The 60% to 90% reduction in penalty rates contemplated under the May 11 proposal would be an explicit signal to reduce spending on those preparations. It would also render the capacity prices to be paid in the 2024/25 delivery year unjust and unreasonable, as they reflect the status quo level of Capacity Performance risk."

State regulators and consumer advocates said in a May 22 *letter* that PJM deliberately included high penalties when it proposed CP to FERC in 2014 in order to incentivize investments to improve reliability. Stakeholders had been asked to consider changes to that paradigm through an expedited quick-fix process in under a month, they said. They noted that PJM has stated that it plans to release a report on the impact of Elliott in mid-July; without that, they cannot come to an informed decision.

"Modifying one component without an opportunity to discuss other aspects would be a mistake," the state officials said. "It has been stated that consumers have paid billions of dollars for the enhanced reliability measures afforded by the existing Capacity Performance construct. While the stakeholder-approved proposal modifies the risks for resources, it does nothing to ensure reliability or ensure consumers are getting fair value for the overall construct."

Several generation and transmission owners also sent a *letter* to the board on May 17, saying CP has encouraged investments, such as winterization or upgrades to reduce startup times, which would be undermined by the proposed penalty reductions. Introducing those changes in delivery years for which auctions have already been run would amount to retroactive ratemaking.

"To provide adequate incentives for performance during emergencies, PJM imposed a carrot-and-stick approach, penalizing resources that failed to perform and rewarding those that exceeded expectations," the GOs and TOs said. "The proposed penalty reductions severely mute the incentives of that framework resulting in capacity market incentives similar to those in place prior to the 2014 polar vortex events. ... However, as a result of Winter Storm Elliott and the penalties assessed to generators for failure to perform, some stakeholders are now seeking to shift resource performance risk back to retail and wholesale suppliers and customers who have little ability to manage that risk." ■

PJM News

NJ Senate Approves Two BPU Commissioners

Guhl-Sadovy, Abdou Backed to Help Execute Clean Energy Policies

By Hugh R. Morley

The New Jersey Senate approved two new commissioners — Christine Guhl-Sadovy and Marian Abdou — for the state Board of Public Utilities (BPU) last week, bringing the five-member board to full strength as it heads the state's ambitious clean energy program.

Guhl-Sadovy, who has a history of working in clean energy and most recently was cabinet secretary for Democratic Gov. Phil Murphy, will replace Robert Gordon, a Murphy appointee whose term expired March 15. The Senate backed her with a 22-14 vote that ran along party lines; Abdou, who drew support from both parties, was confirmed by a 30-0 vote.

Abdou, managing senior counsel at NRG Energy, will replace Dianne Solomon, who was nominated by Republican Gov. Chris Christie in 2013 and whose term expires in October 2024. Abdou has also worked at Direct Energy and Hess Corp.

The two commissioners will join the BPU as it implements an extensive portfolio of clean energy projects in line with the policies of Murphy, who outlined a plan in February for the state to accelerate its carbon reduction programs and reach 100% clean energy by 2035. Murphy had previously set out a goal in the Energy Master Plan of 100% clean energy by 2050.

Electric Transmission Policy

The projects include a third solicitation for offshore wind projects to help the state reach a goal of 11 GW, and implementation of new solar incentive programs, including a permanent community solar and grid-scale solar initiatives. The agency also is overseeing a host of incentive programs to promote the purchase of electric vehicles and the installation of chargers, and a push to replace fossil fuel boilers and heating systems with electric systems.

Former Commissioner Robert Gordon | *NJ BPU*

The BPU is also faced with engineering an upgrade to the state grid necessitated by increased amounts of variable renewable generation.

This month FERC *appointed* BPU President Joseph L. Fiordaliso to the Joint Federal-State Task Force on Electric Transmission. The agency focuses on topics related to planning and paying for transmission — including facilitating generator interconnection — that provides benefits from a federal and state perspective.

Fiordaliso, who was nominated by the National Association of Regulatory Utility Commissioners, has frequently expressed concern about the ability of New Jersey's grid to handle the extra load of the state's rapidly expanding clean energy generation sector. Fiordaliso and Commissioner John B. Howard of the New York Public Service Commission will replace Chair Jason Stanek of the Maryland Public Service Commission, and Chair Gladys Brown Dutrieuille of the Pennsylvania Public Utility Commission.

Both resigned from the task force effective May 1; Fiordaliso and Howard will serve the remainder of their predecessors' one-year terms, which expire Aug. 31.

The Task Force is comprised of all FERC Commissioners, as well as representatives from 10 state commissions.

Implications for New Jersey

Murphy nominated Guhl-Sadovy and Abdou in March, and they secured approval from the Senate Judiciary Hearing on March 20 in the face of some skepticism from both Democrats and Republicans. GOP lawmakers then stymied an effort to use an accelerated schedule to get the nominations approved at a Senate session the same day.

Guhl-Sadovy joined the Murphy administration at the BPU, where she rose to the position of chief of staff to Fiordaliso, according to her biography on the state website. She helped "spearhead" Murphy's clean energy agenda, working on the governor's 2019 Master Plan,

Christine Guhl-Sadovy | *New Jersey Chamber of Commerce*

the implementation of the 2018 Clean Energy Act and the development of the state's EV incentive plan, according to the website.

She previously had spent five years advocating for clean energy policies at the New Jersey branch of the Sierra Club, where she worked on the Beyond Coal campaign, which seeks to close all the coal-fired plants in the U.S. Subsequent to that, Guhl-Sadovy was political director for Planned Parenthood Action Fund of New Jersey and worked to elect pro-women's health candidates, according to the site.

Guhl-Sadovy told the Judiciary Committee that she considered the position "the opportunity of a lifetime."

"Climate change has far-reaching impacts globally and severe implications for New Jersey," she said. "We cannot afford inaction. That's why I'm proud to serve in Governor Murphy's administration, where we have put New Jersey at the forefront of addressing climate impacts by investing in clean energy."

Abdou joined NRG in 2016 and has worked on a variety of commercial issues affecting the company's generation assets and provided legal support to both the development and energy services groups, according to Murphy's office. The company generates electricity and provides energy solutions and natural gas to millions of customers, according to the company website. NRG operates 10 natural gas plants, a nuclear plant, a solar plant and four coal plants, according to the site.

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Abdou said that after her career as a "corporate generalist," she believed the skills she accrued would serve her well on the BPU.

"I do not take lightly the responsibilities of the position for which I have been nominated," she said "While at present time I am not a subject-matter expert on the inner workings of the BPU, I pledge that if confirmed I will apply the same skills that I have used throughout my professional legal career — namely, I will educate myself on the facts, give due consideration to the facts at hand, and used a measured and balanced approach to reach a conclusion."

More than Science and Policy

Both Democrats and Republicans sitting on the Senate Judiciary Committee had concerns.

Sen. Jon M. Bramnick (R) said that when he interviewed Abdou he assumed that Murphy would pick someone "who wasn't going to be fair or objective" but support his "fairly extreme" policies. He said he went through the

Commissioner Dianne Solomon | *NJ BPU*

policies with her "and I got no sense that you had a preconceived opinion prior to going on this board, your background was corporate, it was very objective, and actually the least political person I have met.

"You knew nothing about the politics, nothing about the process, actually nothing about the whales, nothing about the windmills, and nothing about electrifying the entire state of New Jersey," Bramnick said in the hearing. "So, I felt that was a good start. Let's be clear. We hope, and I am sure you will be, that objective person."

Before supporting the two nominations, Sen. Paul Sarlo (D), said he supports clean energy, but has concerns that as commissioners they and their board colleagues need to take a broader view of the impact of their decisions than simply the science and logic.

"I don't want people to think that we're going there to make an eighth-grade science project," he said. "We have to be practical. I implore all those who serve on the BPU: There's much more to the science and the policy. There's a practicality aspect, and there's a cost aspect, and we have to make sure we balance the needs of both of them." ■

PJM News

NJ $1 Billion OSW Port and Marshaling Hub 60% Finished

Custom Facility Targets East Coast Service Role

By Hugh R. Morley

LOWER ALLOWAYS CREEK, N.J. — On a wind-swept tract in the shadow of three nuclear plants, New Jersey's massive $1 billion play to jump start a new energy industry based on harnessing wind power is proceeding apace on the banks of the Delaware River.

Construction of the New Jersey Wind Port, a 200-acre marshaling, manufacturing and logistics hub for the offshore wind sector, is on schedule and on track for completion of the first phase in April. Phase one will be capable of simultaneously handling multiple turbine towers more than 400 feet long, state officials say.

That phase, with a $550 million price tag funded with state money, will be followed by a second phase, expected to begin construction in early- to mid-2024, with an additional expense of about $550 million. The target completion date is 2027 or 2028.

State officials say they are building the nation's first custom-designed port able to handle the growing offshore wind (OSW) sector and capable of handling several projects at once, including those inside New Jersey and along the East Coast. And on a recent afternoon, as a state official led a tour of the site for *RTO Insider*, there were few signs that the state's massive commitment to wind energy has been sapped by the controversy over a spate of whale deaths in the region or recent opposition to turbines that will stretch more than 900 feet into the air.

"We're at 60% completion; we're on or ahead of schedule," said Jonathan Kennedy, vice president, infrastructure, of the New Jersey Economic Development Authority (EDA), which is funding the port and has overseen its development since Gov. Phil Murphy first announced the plan in June 2020.

"That's a pretty rapid mobilization and progression from planning to construction," Kennedy said. "If you came back here April 1, '24, you should be looking at a complete port, fully operational, that's licensed by the Coast Guard.

"The driver here is that we have a non-negotiable need to get this port complete on time," he said.

Emerging Need

That driver is the 1,100-MW Ocean Wind 1, the state's first offshore wind project, which was approved in 2019 and is scheduled to begin construction next year. The state Board of Public Utilities (BPU) has since approved two more projects, the 1,148-MW Ocean Wind II and 1,510-MW Atlantic Shores, in the state's second solicitation in 2021. (See *NJ Awards Two Offshore Wind Projects*.)

Construction of the New Jersey Wind Port on the bank of the Delaware River in South Jersey | © *RTO Insider LLC*

A third solicitation launched by the BPU on March 6 could approve projects totaling 4 GW, and perhaps more, as the state reaches for a goal of 11 GW of OSW capacity by 2040. (See *NJ Opens Third OSW Solicitation Seeking 4 GW+*.)

The EDA has steadily crafted a sweeping plan to create a support infrastructure around the offshore projects that includes a flagship research hub, small business nurturing programs to provide a groundswell of qualified contractors, and a Wind Institute for Innovation and Training.

At its May meeting, for example, the board approved five grants totaling $3.7 million for programs to train OSW workers and $500,000 for a marketing and communications budget for the wind port, including a new website. The board also backed $6 million in expenditures for construction and test piling done in the land parcel for the second phase of the port.

"New Jersey has a choice of whether we want to lead, follow or be left behind by the clean energy revolution, particularly offshore wind," Tim Sullivan, EDA's CEO, told an assembly budget committee hearing on May 17. "And that is an opportunity that if we don't capitalize on it, I promise you, governors and legislators and other states will. And it'll be gone, and we will have missed this generational opportunity."

Hard Hats and Piling

The half-built port, on a recent afternoon, was a hive of activity. A cluster of a dozen half-sunken gray piles soared 30 feet into the air in one section, awaiting attention from a massive yellow crane to pound them down to ground level, ready to support the port marshaling platform. Nearer the water's edge, workers in black and blue hard hats and bright yellow vests readied rows of steel rebar that would eventually be swathed in concrete to become the berth at the water's edge.

A few hundred yards away, in the undeveloped section that will become phase two, workers drained water out of sand dredged from the river through a giant sucking pipe.

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The first phase of the port, on about 125 acres, will consist of two berths, a 35-acre marshaling yard and two parcels totaling 55 acres for manufacturing. The first phase of the construction will require 1,850 piles, each 110- to 120-feet long and weighing 100,000 pounds. About half of the piles are in place.

They will support a wharf able to handle 6,200 pounds per square foot, enough to take the weight of two or more turbine towers as they are assembled and readied for shipment out to the wind farm in an upright position.

The second phase will add two berths, a 35-acre marshaling yard and 70 acres of additional manufacturing space.

As construction advances, workers are dredging a nearly one-mile channel to a depth of 45 feet to take vessels from the port to the river's main navigation route. Although that work has stopped at present, so as not to disturb sturgeon in the river, dredging will resume July 1 for the final push to get the port ready.

Scheduled Marshaling

The need for a custom port lies in the specifics of OSW project creation, the EDA says: Turbines are far larger and heavier than most cargo; a regular port berth typically cannot take the weight or size. And the best way to install turbines is to do most of the construction onshore and ship them to the wind farm upright, which requires a route that has no height restrictions, specifically bridges, on the relevant waterway.

Both Denmark-based Ørsted, which is developing the two Ocean Wind projects, and Atlantic Shores, a joint venture between EDF Renewables North America and Shell New Energies US, have signed letters of intent with the BPU to conduct marshaling for their respective ventures at the port.

When the second phase is finished, the port will be able to handle the marshaling for more than one project at once, but the timing of Ocean Wind I and Atlantic Shores, which were approved two years apart, is such that they are not expected to need marshaling space at the same time, Kennedy said.

"Typically, it takes two to three years to marshal for a project of 1 to 1.5 GW," Kennedy said. "The way this port is designed to work is obviously the marshaling parcels will keep getting flipped. Your new projects will come in, and they'll take two- to three-year leases."

The EDA determined that having the capacity to handle more than one project at a time was important, in part, to strengthen the state's offshore wind sector by "ensuring that no one developer locked up the port," preserving competition, Kennedy said.

Workers prepare piles to be pounded into the ground at the New Jersey Wind Port in Lower Alloways Creek, South Jersey. | © RTO Insider LLC

"We want all bidders on the BPU solicitations to have marshaling port capacity available in New Jersey, should they be successful in that solicitation," he said.

The third phase *solicitation document* makes clear the port's importance to the state's OSW ambitions.

"Consistent with New Jersey's commitment to position the state as a regional offshore wind hub, the BPU strongly encourages use of the New Jersey Wind Port for project marshaling and for locating Tier 1 manufacturing facilities, where feasible," the document says.

So far, Siemens Gamesa Renewable Energy, Vestas-American Wind Technology, Beacon Wind and GE Renewables — all prominent offshore wind players — have expressed interest in the past, but it is unclear whether that interest will move ahead. (See *NJ Wind Port Draws Offshore Heavy Hitters*.)

Kennedy says the EDA is bullish on the question of whether the massive investment is worth it.

"We think there's going to be continued demand for marshaling, you know, out 20-, 30-plus years," he said. "We feel like the pipeline of projects that will need marshaling capacity extends well into 2040, 2050 and beyond."

Turbine Size Increasing

The need for space is fueled, in part, by the rapid increase in turbine size as technology evolves. While turbines deployed in Europe 25 years ago had a capacity of about 2MW, Ocean Wind 1 will use a 14-MW GE Haliade turbine with 360-foot-long blades and total height of 920 feet. Atlantic Shores will use a 15-MW turbine made by Vestas Wind Systems, with 380-foot-long blades.

"Turbines are getting bigger, more efficient, [with] increased output," Kennedy said, adding that increased efficiency is good for ratepayers but adds to the burden on ports handling them.

"The weight-bearing capacity of the wharf, the dredge depth, the backlands, strength and acreage — all of those things don't exist, typically, in a port," he said. "So that's why we're building a port."

The state picked the site from multiple options, narrowing their choices to the Delaware River site and a 50-acre site that formerly housed an oil-fired power plant in South Amboy, opposite Staten Island at the mouth of the New York harbor. The Delaware River site, on a tract that also includes three nuclear power plants operated by PSE&G, had several benefits, including

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the fact that it was a greenfield site, and so required little remediation, Kennedy said.

Another benefit is the lack of height-limiting bridges on the 60-mile trip between the port and the sea. Any height limitations from a bridge would require the turbines to be moved in a horizontal position by barge and elevated at the final destination, a more complicated, expensive and time-consuming process, he said.

In addition, the large space available at the New Jersey Wind Port, 220 acres, means turbines can be manufactured and assembled on-site.

"You're effectively wheeling the components out of the factory doors, straight onto the marshaling parcel," Kennedy said. "And that, again, is good news for ratepayers, because it means you can manufacture and install these components cheaper than if you had to, say, you know, manufacture them elsewhere.

"Time is money with offshore wind, in terms of vessel costs, and other factors," he said. "You need a large acreage, because you need to get as many components in and lay them down as possible, so that they're ready to be assembled and shipped back out. You don't want to be waiting for pieces to arrive, because the installation vessel is so expensive."

Growing Competition

Whether all that is enough to make the port attractive beyond state borders remains to be seen. Kennedy and others at the EDA said the state has a first-mover advantage and a prime location.

"Basically, we have fortuitously located geographically in the middle of the (East Coast) wind belt," which now stretches from Maine to South Carolina, Kennedy said.

Yet, competing marshaling and manufacturing facilities are also emerging along the coast. Wind ports of some scale are planned for New Bedford, Mass., New London, Conn., and in New York, at the South Brooklyn Marine Terminal, from where turbines will have to head out to sea lying flat on a barge to pass under the 230-foot-high Verrazano Narrows Bridge.

The Port of Virginia in August allocated $223 million to the construction of a 72-acre port, with a staging area and 1,500-foot berth. And in Maryland, Ørsted and US Wind are investing in OSW port and manufacturing facilities at the Tradepoint Atlantic that Maryland Gov. Wes Moore *announced* in April "is on track to become the offshore wind capital of America."

Kennedy, however, cited a *2022 study* that suggested the region will need whatever port and marshaling facilities are developed.

The study, by two University of Delaware researchers, concluded that the need for marshaling facilities is a "key bottleneck" in the push to meet state and federal offshore wind policies. The researchers calculated that state and federal offshore wind commitments would create projects with a collective capacity of 40 GW by 2040, stimulating "more demand for marshaling area than is currently available or planned."

"The shortage of marshaling area supply has incorrectly been attributed to lack of suitable U.S. locations," the report said. "Instead, we attribute it to developers having built ports to support early, smaller projects … rather than developing ports for long-term, large-scale, and economically efficient use." ■

PJM News

PJM MRC/MC Preview: May 31, 2023

Below is a summary of the agenda items scheduled to be brought to a vote at the PJM Markets and Reliability Committee and Members Committee meetings Wednesday. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider*.

RTO Insider will be covering the discussions and votes. See next week's newsletter for a full report.

Markets and Reliability Committee

Consent Agenda (9:05-9:10)

The MRC will be asked to endorse:

D. proposed *revisions to Manual 3*: Transmission Operations resulting from its periodic review. The proposed language updates references in the document and aims to add clarity.

E. proposed *revisions to Manual 11*: Energy and Ancillary Services Market Operations related to real-time values through its periodic review. The changes are largely typographical.

F. proposed *conforming revisions to Manual 11* to implement the transmission constraint penalty factor proposal approved by the committee during its Nov. 16, 2022, meeting. (See *FERC Approves PJM Proposal to Reduce Congestion Penalty During Grid Upgrades*.)

Issue Tracking: *Operating Reserve Demand Curve (ORDC) & Transmission Constraint Penalty Factors*

G. proposed *conforming revisions* to Manual 11, Manual 27: Open Access Transmission Tariff Accounting and Manual 28: Operating Agreement Accounting Market Operations related to the hybrid resources phase 1 package approved by the MC on Feb. 23. (See "MIC Endorses Proposal on Hybrid Resources," *PJM MIC Briefs: Nov. 2, 2022*.)

Issue Tracking: *Solar-Battery Hybrid Resources*

H. proposed *revisions to Manual 15*: Cost Development Guidelines related to the heat input guidelines and the Independent Market Monitor's opportunity cost calculator. The changes to the heat input guidelines include documenting the current methods for units to develop their heat input curves, while the opportunity cost calculator changes include a description of a two-hour look-ahead window for the commitment and de-commitment of generators in the calculator.

Issue Tracking: *Opportunity Cost Calculator 2023* and *Combined Cycles and Specialized Boilers Heat Input Guidelines*

I. proposed *revisions to Manual 36*: System Restoration as part of its periodic review.

Endorsements (9:10-9:50)

1. Synchronized Reserve Requirement for Reliability (9:10-9:50)

A. PJM's Donnie Bielak and Phil D'Antonio will *present* proposed revisions to Manual 11 section 4.3 and Manual 13: Emergency Operations section 2.2 to correspond with the increase to the synchronized reserve requirement announced at the May 11 Operating Committee meeting. The revisions seek to clarify when PJM can increase the reserve requirements. (See "PJM Doubles Synchronized Reserve Requirement," *PJM OC Briefs: May 11, 2023*.)

B. Monitoring Analytics President Joe Bowring will give a *presentation* on the Monitor's perspective on the increase.

Members Committee

Consent Agenda (1:05-1:10)

The MC will be asked to endorse:

B. proposed *tariff and Operating Agreement revisions* addressing renewable dispatch. The proposal was endorsed by the MRC at its April 26 meeting and is intended to provide dispatchers with more data to aid in anticipating the output of renewables. (See "Renewable Dispatch," *PJM MRC Briefs: April 26, 2023*.)

Issue Tracking: *Renewable Dispatch* ■

— Devin Leith-Yessian

SPP News

FERC Sides with SPP over Interconnection Study Complaint

By Tom Kleckner

FERC last week denied a solar farm developer's tariff waiver request and a complaint against SPP over the RTO's interconnection studies for the planned facility (*EL22-89*).

The commission issued an order May 23 finding that Cage Ranch, a 900 MW project in West Texas, had not met its burden to show that SPP violated its tariff or conducted its studies in an unjust and unreasonable manner. It said the solar facility did not demonstrate the study models underlying the cluster study were defective.

Cage Ranch said in an amended complaint that the study in question should not have been used to determine interconnection costs for the solar farm and other customers in the study group because SPP failed to resolve alleged nonconvergence issues. But FERC pointed out that the grid operator assigned Cage Ranch network upgrade costs using a modeling approach it applies to all interconnection customers.

The Cage Ranch developers last year challenged SPP's use of what it called a "defective" study model that assigned interconnection costs and calculated its security obligations within its study cluster. It asked FERC to direct the grid operator to resolve the study model's defects, allow interconnection customers to post security after the defects are resolved, and require SPP to restore the customers' queue positions in the study cluster.

Cage Ranch also requested a tariff waiver to extend a decision point deadline until FERC resolved the complaint and SPP issued an updated and corrected study. The commission denied the request, finding Cage Ranch did not satisfy the criteria for such requests (the applicant acts in good faith, the waiver is of limited scope, it addresses a concrete problem, and it does not have undesirable consequences).

OPPD Show-cause Order Ended

The commission also accepted SPP's tariff changes revising Omaha Public Power District's (OPPD) protocols, effective January 2024, and terminated a show-cause proceeding under Section 206 of the Federal Power Act (*ER23-72*).

FERC has rejected a solar farm's complaint over alleged faulty interconnection studies. | *Entergy Arkansas*

FERC issued the show-cause order last July after determining that OPPD's protocols under the tariff appeared to be unjust and unreasonable. The commission directed SPP to either show cause as to why the protocols remained just and reasonable or explain the changes that could be made to remedy the identified problems should FERC find the protocols unjust and unreasonable.

In an order issued May 22, the commission found SPP's proposed revisions to be just and reasonable and consistent with precedent established in 2015 by MISO protocols orders. FERC said the revisions resolved unclear wording and three technical errors identified by two protests late last year.

The commission said the revisions remedy the show-cause order's identified concerns and terminated the proceeding.

As amended, the revisions require OPPD to respond to information or document requests within seven business days, giving parties additional time to review and raise informal challenges. ■

Midwest news from our other channels

Mich. Utility Task Force to Start Hearings June 9 on Outages

ERO Insider

RTO Insider subscribers have access to two stories each monthly from *NetZero* and *ERO Insider*.

SPP News

Texas PUC Rejects SWEPCO Application for Renewables at Pirkey

Kathleen Jackson Joins Commission

By Tom Kleckner

Texas regulators on Thursday rejected Southwestern Electric Power Co.'s (SWEPCO) application to build renewable generation resources at the site of a coal plant that ceased operations in March.

The Public Utility Commission rejected an administrative law judge's proposed decision and denied SWEPCO's application for a certificate of convenience and necessity to construct 237 MW of accredited renewable capacity where the coal-fired Pirkey Plant has stood for 37 years (*53625*).

SWEPCO's parent company, American Electric Power, announced in 2020 it would retire the 580-MW plant to comply with environmental regulations. Opponents of the closure said the plant should operate for another 22 years. (See *Texas Lawmakers Push to Save Retiring Coal Plant*.)

The utility issued requests for proposals for three options: wind, solar and short-term capacity purchases. It told the PUC the facilities would have a nameplate rating of 1,000 MW, translating to 237 MW of accredited capacity.

PUC Commissioner Will McAdams | *AdminMonitor*

Commissioner Will McAdams criticized SWEPCO's argument in a *memo* filed before the open meeting, saying the facilities' accreditation would likely be less than 237 MW. He said the utility failed to "properly account" for the change in accreditation methodology underway at SPP, which is re-evaluating its policy on intermittent resources' capacity contribution at peak. McAdams chairs the SPP stakeholder group re-evaluating that policy.

"This decision to limit the RFPs to these three options was based on flawed assumptions and led to inadequate consideration of alternative generation options," McAdams wrote. SWEPCO's "analysis also failed to consider the approximately $200 million that SWEPCO will try to recover from ratepayers in unrecovered costs, and the intervening cost of capacity purchases that would be necessary while waiting for these proposed facilities to be built."

He said SWEPCO failed to adequately evaluate available alternatives, including power purchase agreements and converting Pirkey to natural gas. "I am keenly aware of the pressing need for dispatchable generation in" SPP, he said.

Pirkey Power Plant | *Oklahoma Municipal Power Authority*

McAdams also noted the Louisiana Public Service Commission's April rejection of a proposed settlement with SWEPCO. The PSC denied the agreement because it said the utility failed to adequately consider PPAs as an alternative to the proposed facilities (*U-36385*).

AEP has made no bones in recent years about increasing its renewable energy output and shutting down its less efficient coal plants.

"One closing thought for SWEPCO's benefit and, frankly, all of our non-ERCOT utilities," McAdams told SWEPCO representatives: "I think what Texas needs, and what you could be invaluable in helping us with, is a message to [AEP headquarters in] Columbus [Ohio] … that the environment you're operating in is changing; the ability for you to meet the core responsibility of that regulated utility — which is the reliability of your system — is being affected.

"The reserve margin in SPP is declining in terms of an accredited value being provided. In a system like that, the whole construct of not just capacity [and] resource adequacy but overall reliability is being pressured," he added. "We understand the need to diversify your portfolio, but we need it to be done in a balanced, methodical way in the very near future, because it's the near future that we are very concerned about."

The order led Guggenheim Securities analyst Shar Pourreza to say AEP needs to "reassess" its regulatory affairs leadership following the latest in "repeated missteps," *according* to Seeking Alpha.

"While fundamentals are a question mark, the real facet of this AEP story is more centered on regulatory strategy and execution," Pourreza wrote. He said AEP CEO Julie Sloat may need to "reassess the company's regulatory affairs leadership and approach given the optics of repeated missteps where unabashed confidence continues to be followed by denials and disappointing outcomes."

AEP's share price closed at $82.25 on Friday, down $2.08 (2.47%) from its $84.33 open the morning of the PUC's open meeting.

Scott Blake, AEP's director of media relations and policy communications, declined to respond to Pourreza's comments but said the company is focused on a settlement in Arkansas and "following through" on the process in Louisiana.

"We will be reviewing the details of the PUCT's order to understand the full scope of the commission's decision and determine our next steps in Texas," he said in an email to *RTO Insider*.

Senate Confirms Jackson

The Texas Senate on Friday *unanimously confirmed* Kathleen Jackson's appointment to the PUC.

Gov. Greg Abbott nominated Jackson to the commission in August, when the legislature was not in session.

"I am grateful to Gov. Abbott and the Texas Senate for trusting me with this responsibility," Jackson said in a statement. "As our state continues to experience incredible growth, the Public Utility Commission of Texas' mission to ensure reliable and affordable power has never been more important."

Jackson has been tasked with leading the PUC's efforts to improve the grid's energy efficiency. ■

Company Briefs

Georgia Power's Unit 3 at Vogtle Reaches 100% Power

The first of two new nuclear reactors at Georgia Power's Plant Vogtle reached 100% power for the first time, the company announced on May 29.

Georgia Power said Unit 3 reached its maximum output of 1,100 MW Monday morning, but it still must put the unit through a battery of tests before it can be synced with the grid and dispatched for commercial operation.

The unit is expected to begin delivering power in June.

More: *The Atlanta Journal-Constitution*

Ford EV Owners to Access Tesla Supercharger Network Next Spring

Ford last week announced that all current and future Ford EVs will have access to about 12,000 Tesla Supercharger stations in the U.S. and Canada starting next spring.

Ford CEO Jim Farley and Tesla CEO Elon Musk announced the agreement during a "Twitter Spaces" audio chat.

Farley said there will be a cost to Ford owners, but he did not give specifics.

More: *The Associated Press*

Drax to Base Carbon Capture Business in Texas

British green energy company Drax last week announced plans to base its carbon capture business in Houston.

The facilities it aims to develop could generate dispatchable renewable power fueled by wood waste and capture more carbon than is created in the process.

Drax, which also manufacturers biomass pellets, gets its residual wood waste from sawmills and other sources.

More: *Houston Chronicle*

Savion, Toyota Sign Solar PPA on Former Kentucky Coal Mine

Solar developer Savion and Toyota last week announced the two have inked a 100-MW virtual power purchase agreement for a brownfield project in Kentucky.

The project will convert a former coal mine into a solar plant developed by Savion along with local developer Edelen Renewables.

Construction is expected to begin in mid-2023 with commercial operation in 2024.

More: *PV Tech*

Federal Briefs

House Fails to Override Biden Veto of Solar Tariff Resolution

The U.S. House of Representatives last week failed to garner enough votes to overturn President Joe Biden's veto of a measure that would have rescinded his two-year moratorium on tariffs for imports of solar equipment from four Southeast Asian countries.

The vote count ended at 214-205, falling short of the two-thirds majority required to override the veto. Eight Democrats voted in favor of the veto override while eight Republicans voted against.

More: *POLITICO*

House Votes to Overturn Biden Truck Pollution Rule

The U.S. House of Representatives last week voted 221-203 in favor of overturning a rule that aims to cut pollution from heavy-duty trucks by 50% by 2045.

The Senate recently approved the same resolution, meaning it will now go to President Biden. However, the White House said at that time if the resolution made it to his desk, he would veto it.

More: *The Hill*

DOE Cancels Grant Following Lawmaker Concerns

The Department of Energy canceled a $200 million grant to lithium battery maker Microvast Holdings following lawmakers' concerns over its alleged links to China.

Rep. Frank Lucas (R-Okla.) and Sen. John Barrasso (R-Wyo.) each wrote Energy Secretary Jennifer Granholm separate letters voicing their concerns about the company's ties to China. The grant was to help Microvast build a plant in Tennessee.

"Neither the Chinese government nor the Chinese Communist Party has any ownership in the company, nor do they control or influence company operations in any way," Microvast CEO Yang Wu said in a statement.

More: *Reuters*, *Reuters*

Interior Dept. Advances Renewable Tx Projects in Nevada

The Interior Department last week announced the advancement of two proposed renewable energy transmission projects in Nevada, which are collectively projected to generate 8 GW.

The Bureau of Land Management confirmed it has begun the environmental review process for the 232-mile Greenlink North project, as well as a draft environmental impact statement for the 450-mile Greenlink West project.

The bureau has set a goal of late 2024 for a final decision on Greenlink West and a goal of draft environmental planning documents for Greenlink North by the end of the year.

More: *The Hill*

IEA: Solar Investment to Overtake Oil for First Time

Investment in clean energy will extend its lead over spending on fossil fuels in 2023 with solar projects expected to outpace outlays on oil production for the first time, according to the International Energy Agency.

Around $2.8 trillion is set to be invested in

energy worldwide in 2023, of which more than $1.7 trillion is expected to go to renewables, nuclear power, EVs and efficiency improvements. The rest will go to oil, gas and coal.

"For every dollar invested in fossil fuels, about 1.7 dollars are now going into clean energy. Five years ago, this ratio was one-to-one," IEA Executive Director Fatih Birol said.

More: *Reuters*

Granholm Announces Funding for Tribal Generation, Delivery in Ariz.

Energy Secretary Jennifer Granholm last week met with Arizona tribes and announced funding to modernize and harden the grid, expand renewables, and reduce outages.

The $50 million in grants will fund the Navajo Nation and San Carlos Apache Tribe, as well as four states.

More: *Arizona Republic*

State Briefs

ARKANSAS

Court Blocks EPA's Rejection of State Emissions Proposal

The 8th U.S. Circuit Court of Appeals last week blocked the EPA's disapproval of the way Arkansas planned to implement the Clean Air Act's standards for ozone emissions.

The court's two-sentence order granted Arkansas' request for a stay of the EPA's decision pending resolution of a lawsuit. Arkansas sued the EPA on Feb. 16 over the agency's decision to reject the state's plan to comply with federal emissions rules.

The EPA tasked states with devising proposals to reduce the emission of nitrogen oxides. The agency rejected the implementation plans of 19 states.

More: *Arkansas Democrat Gazette*

CALIFORNIA

New Natural Gas Plant in Lodi Could Prevent Future Outages

The Lodi Electric Utility announced the construction of a 48-MW natural gas plant.

The plant, which is being fully funded by the Department of Water Resources as part of the state's Strategic Reliability Reserve Program, would only be used in extreme peak-demand events to stabilize the grid and avoid local or statewide power failures.

The plant is expected to be operational by the end of summer.

More: *KXTV*

SoCal Edison Substation Vandalized, Triggers Brief Outage

A Southern California Edison substation in Santa Fe Springs was vandalized last week, prompting authorities to shut down the grid, leading to power outages in the area.

According to the Whittier Police Department, the incident occurred just before 1 a.m. on May 21. Police say the suspect crawled into the building and caused $75,000 in damages. More than 9,000 customers in La Mirada, Santa Fe Springs and Whittier were affected. Officials said all power was restored by 5 a.m.

No arrests have been made.

More: *KABC*

CONNECTICUT

Former CT Energy Coop CEO Sentenced to a Year in Prison

Drew Rankin, the former CEO of the Connecticut Municipal Electric Energy Corporation (CMEEC), was sentenced to a year in prison this week for misusing funds.

Rankin, 62, was also ordered to serve three years of supervised release.

During a 2021 trial, evidence revealed that Rankin and other members of the CMEEC Board of Directors organized extravagant trips, including visits to the Kentucky Derby in 2015 and 2016, as well as a luxury golf resort in West Virginia in 2015. These trips were unrelated to CMEEC business and were intended for personal benefit. Costs for the trips exceeded $800,000.

More: *CT News Junkie*

ILLINOIS

Henry County Approves Zoning for Solar Project

Henry County board members last week voted 18-0 to approve a third solar project in the county.

Nexamp said the 5-MW project would go on 25 acres of a 36-acre parcel just north of Kewanee.

It was the third solar project the board has approved in the last three months.

More: *Quad-City Times*

KANSAS

Corporation Commission Approves NextEra Tx Line

The Corporation Commission last week approved the siting and route for a NextEra transmission line that would span five counties.

The proposed route would go through Coffey, Anderson, Allen, Bourbon and Crawford counties, connecting the Wolf Creek nuclear power plant to the Blackberry Substation in Missouri. The move allows construction to proceed, although it is possible the decision will be challenged in court.

Some landowners have argued that the proposed route would have a burdensome impact on their livelihoods and that the environmental impact of the plan has not been properly evaluated.

More: *Topeka Capital-Journal*

LOUISIANA

Entergy Again Files Suit Over $1M City Council Fine

Entergy New Orleans last week filed suit in district court, alleging that the city council is trying to reimpose a $1 million fine in a way that goes against a judge's earlier ruling.

Three years ago, city council imposed a fine in response to reliability issues between 2013 and 2017, which were documented

in multiple investigations. Entergy sued, arguing that the council hadn't set up minimum performance standards and there was nothing to use to evaluate. Judge Rachael Johnson then vacated the fine after calling it arbitrary and capricious.

This year council adopted performance standards for Entergy and, based on those standards, found a $1 million fine would have resulted. The council then set up procedures for reconsidering the previous fine, but Entergy's new lawsuit argues that Johnson's order was final.

More: *Nola.com*

MINNESOTA

Half of Contaminated Water Leaked from Monticello Recovered, Xcel Says

Xcel Energy®

More than half of a radioactive isotope that leaked from a pipe at the Monticello Nuclear Generating Plant in 2022 has been recovered, Xcel Energy officials said last week.

The leak allowed 400,000 gallons of water containing tritium to spill. Monticello city leaders said Xcel, which owns the plant, has collected 53% of the tritium and crews have pumped more than 1.1 million gallons of water at the plant.

The concentration of tritium in the groundwater has declined and there have been no recorded measurements of the isotope beyond the plant, officials said.

More: *The Associated Press*

State to Revamp Community Solar Garden Program

Gov. **Tim Walz** last week signed legislation that will overhaul the state's community solar garden program.

The new program will cater more to residents, particularly lower-income households, but some costs will continue to be passed down to Xcel Energy ratepayers. The Department of Commerce will administer the new program, although Xcel will still assess grid connections for projects chosen by the agency.

The program accounts for more than 60% of the solar energy produced in the state.

More: *Star Tribune*

MISSOURI

St. Charles Files Lawsuit Against Ameren over Water Contamination

The city of St. Charles last week filed a lawsuit against Ameren Missouri over water contamination and damages linked to the Elm Point Wellfield.

The EPA earlier this year said the Ameren substation was the source of the city's water well contamination. Out of seven water wells powered through the wellfield, only one remains currently operational. The water is still safe to drink, but the city has had to purchase around $2 million of additional water from St. Louis over the past five years.

Ameren said it had yet to review the lawsuit.

More: *KTVI*

NEW MEXICO

Community Solar Moves Forward, Developers Chosen

InClime

InClime, a renewable energy-affiliated company, last week chose 45 solar facility projects and gave companies the green light to start the process to set up farms they'll soon operate for the state's community solar program.

The energy generated will go to customers of the Public Service Company of New Mexico, the Southwestern Public Service Company and El Paso Electric who choose to opt in. Renters, homeowners and businesses that choose to be part of the program will not have to purchase and install panels themselves, the PRC said.

More: *Source NM*

PRC Orders El Paso Electric to Fix Billing Mistakes, Give Credits

The Electric Company
El Paso Electric

The Public Regulation Commission last week ordered El Paso Electric to fix billing mistakes and gave the company less than a month to determine how much it will return in credits.

The PRC recently ruled that El Paso Electric had been undercharging some of its largest customers a few years ago while making other people pay higher rates. Now, the company could owe more than $1.19 million to people with accounts.

El Paso Electric will not appeal the decision and is moving to correct the charge to its customers, according to spokesperson Karmen Mayorga. The utility has until June 6 to file a notice with credited rates.

More: *Source NM*

NEW YORK

Olean Issues One-year Moratorium on Large-scale Solar Projects

The Olean Common Council last week voted 6-0 to approve a one-year moratorium on all large-scale solar projects.

The council cited the need to draft updated laws and a comprehensive plan as the reason for the moratorium. During that time, the city will not accept building permit, variance or special use permit applications for such facilities.

The law allows the city to extend the moratorium indefinitely, as well as allowing it to terminate it early after new local legislation regulating the developments is in place.

More: *Olean Times Herald*

TEXAS

House Passes Bill that Allows for More Rate Hikes

The House last week passed a bill that would allow utilities to seek an additional rate hike every year.

The new bill would allow utilities to seek a distribution-cost rate increase twice a year. It would also require approval from the Public Utility Commission alone and reduce the time the PUC has to review the request from 120 days to 60.

The bill now heads back to the Senate.

More: *Houston Chronicle*