ISSN 2377-8016 : Volume 2023/Issue 5 ▪ January 31, 2023

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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Stakeholder Soapbox

Are We Overinvesting in Grid Modernization?

By Kenneth W. Costello

Ken Costello

Grid modernization (GM) investments encompass myriad technologies that digitize a utility's distribution system. They have the potential to improve the reliability of the electrical grid, better integrate alternative energy, and enable pricing that reflects the marginal cost of generation.

The present grid was designed when power plants in central locations exclusively controlled a one-way flow of electricity to customers. A modern grid has the ability to accommodate greater consumer control and two-way flows of power.

Experience has shown that achieving public-policy goals at bearable cost to society frequently requires technological breakthroughs. Many experts assert that making the transition to a clean-energy future at an affordable or politically acceptable cost will demand new technologies, such as those rooted in GM.

It seems then that it is a slam dunk for state regulators to approve utilities' plans to modernize their distribution systems, even if the cost is high. But, to no surprise, things are rarely as certain as they seem. Public utility commissions face a formidable challenge in ensuring that utility investments in GM advance the nebulous public interest or are cost-beneficial.

Pressure for GM comes from different quarters: electric utilities, Wall Street, clean air and climate advocates, GM technology vendors, consultants, labor unions, and state and federal politicians and bureaucrats. Utility managers themselves favor GM mainly because it will accommodate additional demands from electric vehicles and households for electric space and water heating (i.e., electrification).

Proponents of GM vastly outnumber both skeptics and opponents, making it challenging for regulators to reject GM plans proposed by utilities. We know that strong pressure from special interest groups with political clout can persuade policymakers to decide in their favor, even though it would be detrimental to society overall.

Since utility customers are the eventual payers of GM investments, the critical questions that PUCs need to ask themselves, are whether (1) the total benefits from GM to utility customers exceed the costs and (2) low-income households will overpay given that higher-income households will disproportionally benefit from purchases of electric vehicles and rooftop solar systems that GM tries to accommodate. Just because a Tesla is technologically superior to conventional vehicles does not mean that it is the right choice for everyone. It's costly, and some car drivers might consider the technological benefits to be nominal.

I have seen too often where utility customers pay through their rates for utility investments directed at benefitting a special interest with political influence; that is, customers funding the advancement of political objectives through inflated rates without compensatory benefits. I ask whether we are seeing a repeat of this for GM investments. Or as one industry observer expressed to me, "Is grid modernization another way to line utility pockets and promote renewable energy and kill fossil fuels?" While this opinion seems extreme, it may not be so far-fetched.

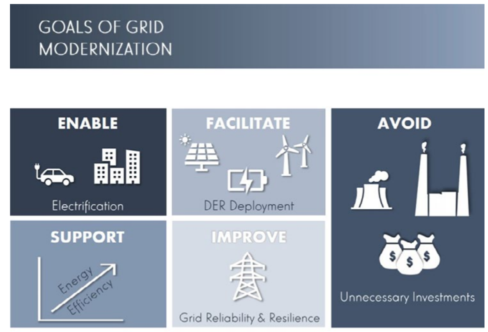
There is great uncertainty over the benefits and costs of GM investments. Costs overruns are common, and benefits are difficult to quantify and require different methods of varying complexity.

A serious problem is a utility's capital bias combined with laxed regulatory cost controls. Under traditional regulation, utilities collect capital costs only after the regulator considers them prudent or reasonable; utilities would be allowed to collect them only after a general rate case.

But for various reasons, regulators have accepted new cost-recovery approaches. Both utilities and climate activists have pushed for quicker and more certain capital-cost recovery when it comes to certain technologies like GM that advance their agenda. Wall Street has also supported these new approaches, fashioning an Iron Triangle that makes it difficult for PUCs to reject them.

Utilities should be held accountable for subpar performance from GM investments. These investments have often fallen short of achieving the benefits promised in utilities' plans.

There is *evidence* that reliability has not improved in states that have so far invested the most in GM. Critics have also questioned whether it is too soon to replace the current infrastructure.



| *Interstate Renewable Energy Council*

Advanced metering infrastructure (AMI) has in some jurisdictions failed to realize expected dispatch efficiencies and cost savings. Most utilities have also under-exploited the ability of AMI to enable granular time-of-use rates (e.g., real-time pricing, electric vehicle charging rates) that can produce large efficiency gains.

Another problem recognized by PUCs is utilities proposing to make large-scale, multi technology investments, some of which have questionable, ill-defined benefits that are unlikely to transpire for several years.

PUCs should not outright reject a GM plan just because it would require an increase in electricity rates or be prejudiced against a plan in spite of the evidence; or accept a plan just because it will support a popular clean energy agenda, while ignoring the effect on utility customers. There is danger that either of these scenarios can happen and probably has already in some states.

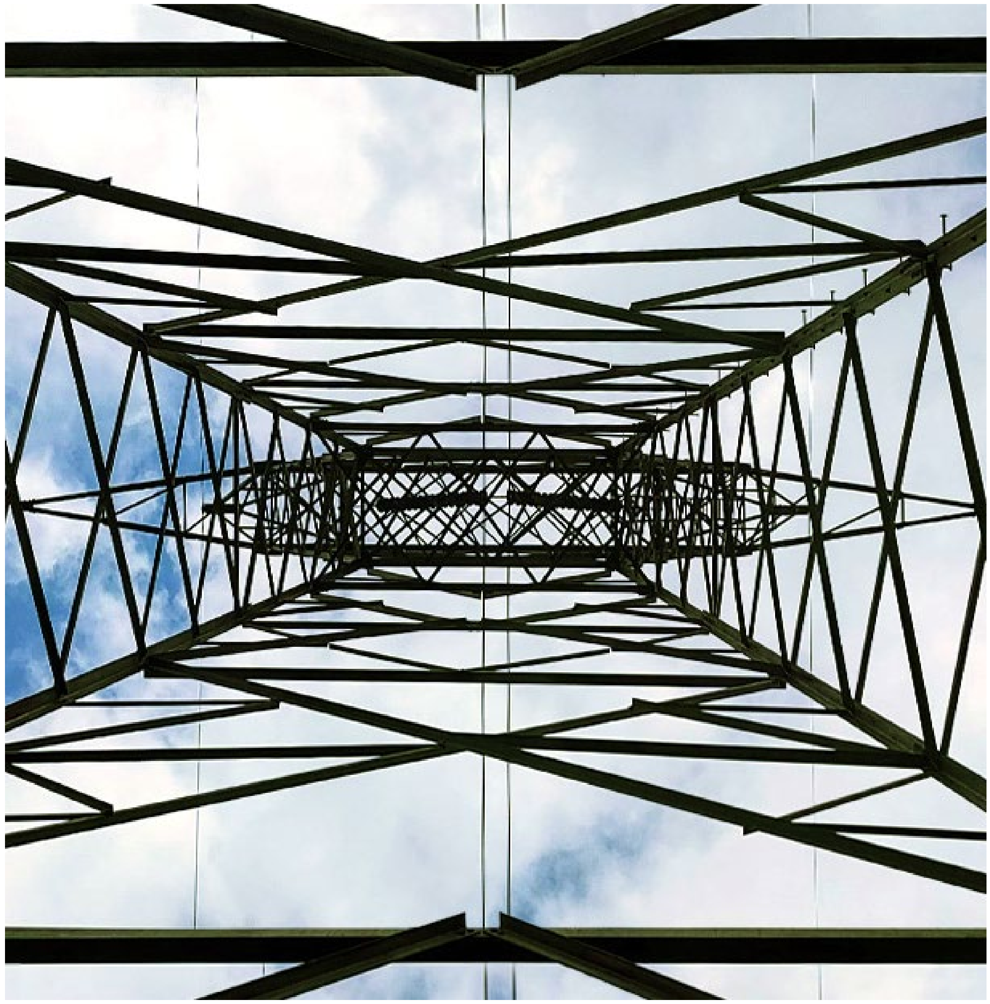
The experiences across states have shown that the benefits from GM plans are often overstated and costs understated. The burden falls on PUCs to ensure that this does not happen. Unaccountability by utilities for their large investments can have a devastating effect on customers and society as a whole. Getting the incentives right is the key element for achieving socially desirable GM investments. ■

Kenneth W. Costello is a regulatory economist and independent consultant. He previously worked for the National Regulatory Research Institute, the Illinois Commerce Commission, Argonne National Laboratory and Commonwealth Edison Co.

FERC/Federal News

Berkeley Lab: Wind Generation Needs More Flexible FTRs

By Amanda Durish Cook



| © RTO Insider LLC

Berkeley Lab researchers say growing renewable generation means it's likely time to retool wholesale markets' designs of financial transmission rights.

In a *study* released Jan. 23, "Rethinking the Role of FTRs in Wind-Rich Electricity Markets in the Central U.S.," Lawrence Berkeley National Laboratory said wholesale markets should consider establishing more flexible FTRs that mimic variable generation profiles to better match congestion rents and payouts. The researchers said more tailored designs would be especially helpful in the wind-rich MISO, SPP and ERCOT markets.

"For an ISO to remain revenue neutral, congestion rent should equal the payout of the FTRs," they said. "Linking FTR payout to the actual utilization of the grid can improve the match between congestion rent and FTR payout."

Berkeley said wind generators don't realize much benefit from FTRs as they're currently designed and recommended improved hedging mechanisms to lower locational basis risk. Congestion often creates divergences in wholesale market prices between individual pricing nodes and trading hubs; the researchers said fluctuations in locational basis can hurt a generator's bottom line, deter investors and ultimately slow renewable energy development.

"Conventional FTRs … are structured around an unvarying or fixed contract capacity, which is not particularly suited to generators with varying output," the report said.

Berkeley researchers recommended the three grid operators design FTRs that can fit variable resources' operational characteristics. They suggested markets develop wind FTRs, where volume varies based on an hourly systemwide aggregate wind profile. A wind generator could then purchase an FTR for a certain capacity, a portion of which would be dispatched based on the day-ahead schedule. The remainder would then be returned to the RTO or ISO at "no cost or profit to the wind generator."

Berkeley also suggested FTRs could become dispatch-contingent so that they would only pay the price difference when the generator is operating or that markets institute "cap FTRs" (where the payout is the difference between the load and generator nodes), but only when the node's price is above a predefined strike price.

The research team acknowledged that "adapting FTR auctions to include new products is not trivial."

Berkeley said that after studying 2015-2019 data from MISO, SPP and ERCOT, the researchers said it's clear that wind plants "face a disproportionately larger" locational basis.

"Empirical data from markets in the central U.S. confirm that wind plants face the largest, and among the most volatile, generation-weighted basis of any type of generator," the report said. "Because wind plants tend to be located far from load centers, they rely on the transmission network to deliver power and are exposed to congestion when transmission capacity is limited."

The research team said while annual fixed-volume FTRs "can nearly eliminate basis for most conventional generators" with steady output, they're "less effective for reducing the average basis for wind."

A fixed-volume FTR reduces wind's locational basis by \$1 to \$5/MWh, according to the report, but still leaves wind generators with an average of \$1.80 to \$3.50/MWh of "residual basis" across the three markets. A wind FTR, on the other hand, could drive down that residual basis to less than \$1/MWh.

A financial consulting firm recently concluded MISO needs to update its auction revenue rights and FTR market to reflect the system's changing flow patterns. Among other recommendations, London Economics International suggested MISO tailor its products to an evolving supply mix and load patterns by offering morning, afternoon, evening and night options. (See *Financial Firm Finds MISO FTR Market Needs Work*.) ■

FERC/Federal News

OSW Tx Planning Must be Interregional, Networked and Start Now

Brattle Report Sees IRA Billions as Key to Jump-start Urgent Reforms this Year

By K Kaufmann

The U.S. will require a massive mobilization of resources and unprecedented collaboration among federal, state and regulatory authorities to build the transmission needed to the meet its aggressive offshore wind goals, a new report says.

Those goals include President Biden's call for 30 GW of offshore wind by 2030 and a national target of 110 GW by 2050.

Such "proactive and holistic" planning efforts could save U.S. consumers $20 billion and reduce environmental and community impacts by 50%, according to the report, "*The Benefit and Urgency of Planned Offshore Transmission*," compiled by The Brattle Group for a consortium of clean energy and grid advocates.

"Compared to the current process of developing and interconnecting one OSW generation project at time, each with its own cables to shore, a coordinated comprehensive transmission plan could unlock numerous efficiencies and benefits unavailable under current processes," the report says.

But "to achieve these benefits, state and federal policymakers, industry regulators, system operators and market participants must expeditiously address" existing obstacles, such as interconnection and permitting reform, the report says. "Even modest delays in developing and implementing actionable plans for both near- and long-term transmission investments substantially reduces [sic] the benefits of such planning efforts."

For example, the report cites a *study* done by National Grid in the United Kingdom finding that a delay of five years in long-term transmission planning would cut benefits — including $7.4 billion in costs savings — in half.

"If we don't carefully plan, it's not just the next 10 to 15 years," said Johannes Pfeifenberger, a principal at The Brattle Group and lead author of the report, speaking at a launch webinar on Jan. 24. "But with a view to 2040 and 2050, we are really prone to severely limit our future options."

The report's to-do list is daunting. In the next year alone, federal and state governments must increase funding and staff for offshore transmission planning, and the Internal Revenue Service must clarify the offshore wind tax credits in the Inflation Reduction Act. Offshore developers are specifically looking for the IRS to confirm that a project's transmission infrastructure will qualify for the tax credit.

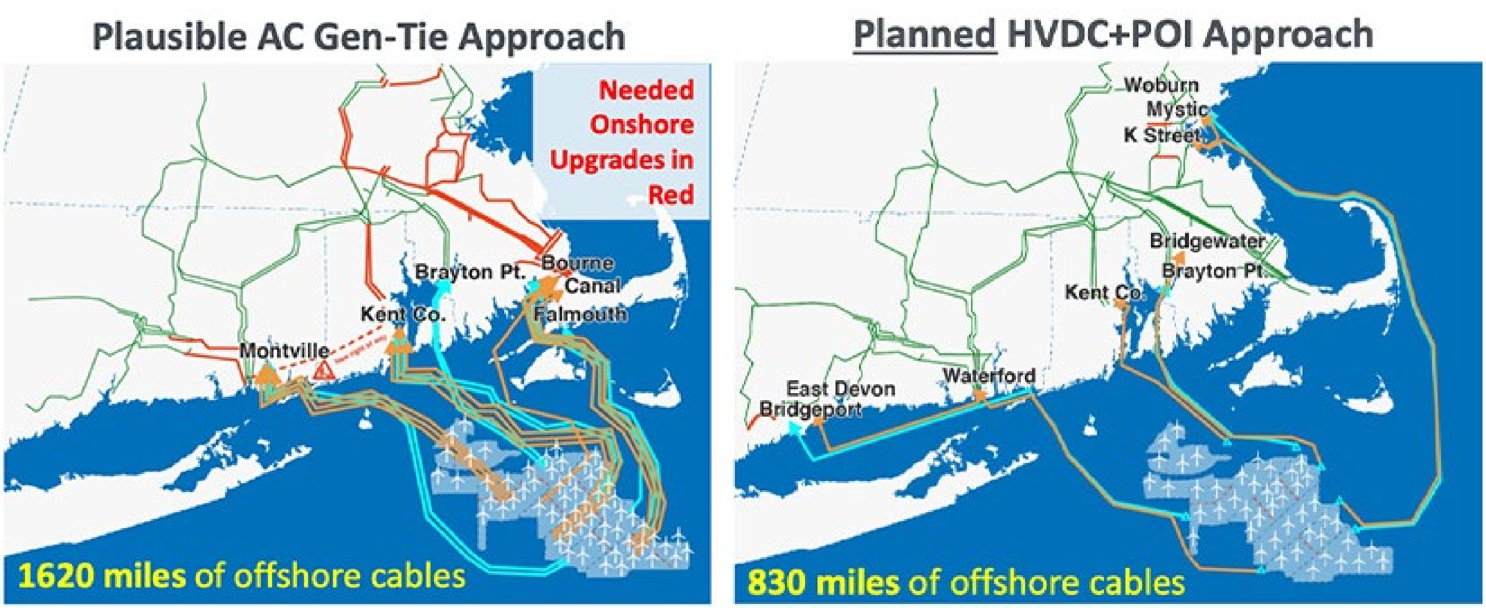
At the same time, states will have to come together to form multistate "transmission authorities," which will "facilitate the planning and procuring of effective regional and interregional transmission solutions," the report says. Federal leasing processes should be changed to lay out "offshore cable routes between projects," and "network ready" standards for offshore substations and cables must be developed to ensure interoperability between projects.

A range of funding opportunities and incentives in the IRA and Infrastructure Investment and Jobs Act should be leveraged to jump-start these and other mid- and long-term recommendations in the report. Potential funding sources in the IRA include $760 million to help with siting of interstate and offshore transmission and $2 billion in financing, such as loan guarantees, for transmission projects the Department of Energy designates as being "in the national interest," the report says.

But, Pfeifenberger said, some IRA funds, such as offshore wind tax credits, sunset in 10 years, which is about how long it takes to permit and build an offshore project and transmission; hence, the need for immediate action. "We won't be able to take advantage of [IRA funding] unless we start to plan for what it is that we need," he said.

A Burning Fuse

A joint project of the Natural Resources Defense Council, GridLab, the Clean Air Task



A 2020 study from The Brattle Group compared unplanned (left) and planned transmission for offshore wind in New England. | *The Brattle Group*

Force, the American Clean Power Association and the American Council on Renewable Energy, the report's call for urgency is rooted in the confluence of the expansion of offshore wind in the U.S. and the federal funding opportunities in the IRA and the IIJA.

In addition to Biden's 30 GW, states on both the East and West coasts have set offshore targets totaling 77 GW by 2045, and a range of studies are projecting the U.S. could need as much as 460 GW of offshore wind to meet its 2050 climate goals, the report says.

Connecting these projects to the onshore grid requires laying underwater cable and finding onshore points of interconnection (POIs) that may run across beaches or through coastal communities, as well as interregional high-voltage DC transmission lines to get power to load centers. Projects and their transmission can take a decade to site, permit and build, making the need for forward planning more urgent, as does the siting of multiple projects near each other, as is now occurring on the East Coast, the report says.

"The days of low-hanging fruit where you have near ready-made POIs are really done, and we're starting to brush up against some really tough nuts to crack in terms of interconnecting these resources," said Robert Golden, senior adviser for clean energy infrastructure at the White House. "The opportunity is huge to deliver for customers, but this is really a bit of a burning fuse, and if we don't move quickly a lot of the benefits … can vanish off the table."

"Current interconnection points are not sufficient to accommodate all the offshore wind that is expected to come online over time," agreed Lopa Parikh, head of electricity policy for offshore wind developer Ørsted, which is currently working on *eight projects* off the Atlantic coast. "So, any proposals for transmission projects that are considered really need to consider the full scope of potential offshore wind development to ensure that they can be accommodated over the long run. … This is especially true since most of the offshore wind is currently being developed close to load centers, which greatly increases the need to create more efficient transmission planning."

The benefits of such coordinated planning could include a 60% to 70% reduction in the need to upgrade onshore transmission lines or run lines across beaches or through coastal communities. The amount of underwater cable needed for projects could also be cut by as much as 2,000 miles, the report says.

"Every time you have to go back and disturb [an] area, that impacts the communities," said Suzanne Glatz, director of strategic initiatives and regional planning at PJM. "There's a lot of value to be extended if we can minimize the number of times we have to go back to those areas."

Suedeen Kelly, a former FERC commissioner and now a partner at law firm Jenner and Block, believes that offshore wind development should be seen as a "unique effort in America. … We shouldn't necessarily try and pigeonhole this planning process into existing frameworks and existing silos."

"We don't really know what the best configuration of an offshore grid is," Pfeifenberger said. "Is it just meshed radial lines? Is it a backbone? Is it some sort of combination of these things? We need a planning process to figure out what is the best configuration for a given region."

At the same time, Pfeifenberger sees interregional offshore transmission planning as providing new opportunities for improving grid reliability and resilience. "We can use the offshore infrastructure to reinforce the onshore grid, and there is a lot of interregional transmission that studies find would reduce total costs faced by consumers significantly, and offshore links may be the most cost-effective way to provide that regional and interregional transfer capability."

He also envisioned "multipurpose connectors … that not only bring offshore wind to shore but also create reinforcement to the onshore grid," he said. The problem, however, is that the HVDC lines that would be used in such networks have a higher capacity than the standard maximum most RTOs and ISOs can handle, even in a "most severe single contingency," Pfeifenberger said.

"That kind of [HVDC] network would really improve the reliability of delivering offshore wind. It allows for higher capacity transmission cables that are … able to reroute power and avoid large impacts on individual grid nodes," he said.

Switching Trains

The report's call for urgent action on transmission planning for offshore wind comes at a time when FERC and RTOs/ISOs are all wrestling with planning and interconnection issues, though their focus has been regional, rather than the interregional coordination the report sees as critical. In addition, Pfeifenberger said, these bodies will also need to work on new frameworks for regulations, contracts and markets.

Brattle has done a number of studies advocating for coordinated planning for offshore wind

FERC/Federal News

for *New York* and *New England*, comparing the cost and impacts of traditional, siloed planning with a holistic, networked approach in which multiple projects can be linked or can share cables and POIs.

"Before we have a networked offshore grid, we will need the regulatory and contractual framework for shared network operations," he said. "The regional grid operators need to tune up their operations and market design because right now they are not ready to handle HVDC links, either within their region or across regions," he said.

FERC's anticipated rulemaking on regional transmission planning "will be very helpful, at least if the final rulemaking is anything like the [Notice of Proposed Rulemaking] itself," Pfeifenberger said. "However, FERC rulemaking won't be effective unless there is also leadership from the regional grid operators and the states."

The lack of collaboration between states and grid operators was one of the factors behind the failure of FERC Order 1000, the grid planning order the commission issued in 2011, he said.

"We're basically trying to develop a process that allows us to switch trains while both trains are moving at high speed from the current process to a better planning process, and that requires a lot of additional thought and preparation," Pfeifenberger said.

Not yet finalized, the NOPR would direct transmission providers to revise their planning processes to, among other things, identify infrastructure needs on a long-term, forward-looking basis and propose a list of benefits on which they would base their selections of proposed projects to meet those needs.

It has had a mixed reception among industry stakeholders. (See *Battle Lines Drawn on FERC Tx Planning NOPR*.)

Following the departure of Richard Glick as FERC chair, the commission is now potentially deadlocked with two Democratic and two Republican commissioners, leaving the future of the rulemaking uncertain.

Kelly sees the regional NOPR as a first step but stressed that it will not cover the kind of interregional planning needed for offshore wind. FERC could, she said, "play a pivotal role initially by becoming a national forum for the provision of information prior to talking about any kind of regulation."

By hosting a series of technical conferences, FERC could provide "a single place where interested developers, states [and other] stakeholders could come" to discuss the issues, she said.

Equal Access Is Key

But developing any new transmission planning processes must not slow down or delay projects already underway, Parikh said. "Making changes to projects that have already been awarded could negatively impact the viability of these projects and the ability for them to interconnect in a timely manner."

PJM's state agreement approach (SAA) with New Jersey is one way forward, Glatz said. Under the SAA, PJM ran a solicitation for the New Jersey Board of Public Utilities for transmission projects to connect 6,400 MW of approved offshore wind projects to the grid. According to the report, the solicitation and the resulting projects chosen by the BPU saved the state $900 million. (See *NJ BPU Oks $1.07B Transmission Expansion*.)

She also pointed to PJM's interconnection reforms, recently approved by FERC, that will shift the RTO from its current first-come, first-served methodology to instead studying new service requests with a first-ready, first-served approach that clusters proposed projects together to determine network impacts and allocate network upgrade costs. (See *FERC Approves PJM Plan to Speed Interconnection Queue*.)

The reforms mean "we can be looking out to not only the first project, what it would take to interconnect that one, but also the one after and the one that comes two or three years after that," Glatz said. "What is that holistic solution to meet the interconnection of those projects?"

But forward planning also carries certain risks. "You are planning for multiple projects, some of which may not be very far along or even yet entered into the interconnection queue," she said. "So, there's a possibility that those will not materialize, and you may have more transmission built that could be more costly."

Glatz also stressed the independent role RTOs play as "organizations that plan the system to meet the needs of all system users, which would mean studying all generation requests in a nondiscriminatory manner and to provide equal access to all of them."

The RTOs' wholesale markets must also provide equal, nondiscriminatory access, Glatz said. "Assuring that the planning process still serves that purpose is really key to anything we're going to consider in terms of potentially prioritizing any resources." ■

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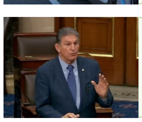

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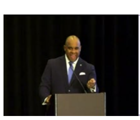

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FERC/Federal News

Top Energy Trade Groups Highlight 2023 Goals at USEA

By James Downing

WASHINGTON — The United States Energy Association on Thursday gathered senior leaders of the major trade associations at the National Press Club, where they focused on implementing major energy legislation passed last year and many argued for reforms to permitting processes.

The passage of the Infrastructure Investment and Jobs Act and the Inflation Reduction Act gives the energy industry plenty to implement, but Edison Electric Institute President Thomas Kuhn said Congress still needs to pass more legislation to make the investments those laws promised a reality.

"One of the things on our priority list is siting and permitting," Kuhn said. "If you want to have the benefits of the two major legislative initiatives over the past couple years, you've got to be able to do siting and permitting more efficiently."

While changes to energy project permitting laws have some bipartisan support, different interest groups have their own ideas, and it will be challenging to bring them together and get something done, he said.

EEI President Thomas Kuhn and USEA acting Executive Director Sheila Hollis | © *RTO Insider LLC*

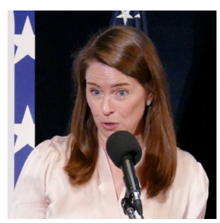
The electric industry has made significant cuts in its emissions over the last 10 years and many utilities have plans to clean up even more in the coming decades, but Kuhn warned against getting rid of all fossil fuels too quickly. With so much changing now, it does not make sense to take a major source of energy away all at once, he said.

"Some people want to take natural gas away," Kuhn said. "You know, I've got to tell you, if you want to do this job and you want to do it reliably and mildly affordably, you're going to need natural gas. It's that simple."

Generators switching from coal to natural gas have helped bring emissions down to 30-year lows, American Gas Association President CEO Karen Harbert said. The gas industry has been trying to clean up and working to cut its methane emissions, she said.

"If the conversation is about reducing emissions, we're all in," Harbert said. "If the conversation is about putting us out of business, not so much. Because there is no way to address energy security, environmental progress, economic security and national security without natural gas in our system."

Interstate Natural Gas Association of America CEO Amy Andryszak argued that many states are enacting policies that favor renewable energy while discouraging new sources of natural gas that would help balance those resources.



Interstate Natural Gas Association CEO Amy Andryszak | © *RTO Insider LLC*

"We know the Northeast is supply-constrained — not due to a lack of available natural gas in the United States," Andryszak said. "Actually, we have the Marcellus right next door. But regulatory decisions and bad policies have contributed to this problem."

INGAA supports "smart policies" aimed at reducing carbon emissions, but, echoing Harbert, Andryszak said if the conversation is really about eliminating natural gas, then the pipeline trade group is against it.

One major policy Congress has to deal with is the debt ceiling, said American Petroleum Institute CEO Mike Sommers, who was involved in such discussions as a senior staffer for Republican congressional leaders in the 2010s.

"There are big things that could get done, like permitting reform on a bipartisan basis, potentially as part of the way that we get the debt ceiling lifted as well," Sommers said. "So, I'm optimistic that this is going to get done. I think we should all get used to some panic moments. But I'm confident that our leaders are going to get this addressed in a timely fashion."

Germany now has five LNG terminals after it worked to replace the Russian-supplied natural gas that it embargoed after the invasion of Ukraine.

Electric Power Research Institute CEO Arshad Mansoor | © *RTO Insider LLC*

"And they built one of them in six months, when the typical receiving terminal is a two- to three-year time period," Electric Power Research Institute CEO Arshad Mansoor said. "So, they figured out when there's a necessity permitting can be streamlined."

Germany has been a leader in moving to renewable energy, but it also has avoided completely retiring coal plants; that decision proved prescient this winter as they had to be used much more often than when the country was awash in cheaper Russian gas, he added.

"I think it's a general belief that for all of us in the research community [and] in the technology community, that we must have optionality in our clean energy transition," said Mansoor.

Natural gas plants are still relatively young when it comes to infrastructure, and Mansoor said that early studies have found that they could run blends of 20% or 40% clean hydrogen to minimize their emissions while maximizing their usefulness to the grid.

The industry has to prepare for more extreme weather and do so ahead of time, Mansoor said. While utilities have often done well upgrading their systems after a natural disaster, climate change means extreme weather will be more common.

"How do you proactively make that investment?" Mansoor said. "Don't wait for the flood; anticipate weather in 2030, 2045, … and start building infrastructure for that weather." ■

Southeast

Industry Group Blames Duke, TVA for Blackouts

SREA Points to Poor Tx Planning, Lack of Market Access

By Amanda Durish Cook

The Southern Renewable Energy Association (SREA) said Thursday that Duke Energy Carolinas' and the Tennessee Valley Authority's Christmas Eve blackouts were likely avoidable had they built more robust transmission links and had better access to organized wholesale markets.

SREA Executive Director Simon Mahan | *SREA*

SREA Executive Director Simon Mahan said during a briefing focused on the Southeast region's performance issues and rotating blackouts during the December winter storm that the region contains a "balkanized, separated grid" where each utility must balance their own system without a shared resource pool to fall back on. (See *FERC, NERC Set Probe on Xmas Storm Blackouts*.)

"With better connections with our neighbors, we can avoid blackouts," he said.

The load shed was a first for both TVA and Duke.

Mahan drew parallels between the recent winter storm and the more severe storm in February 2021. He predicted the Southeast will receive much of the attention for its performance in December because it's isolated from a regional grid, as was — and still is — ERCOT two years ago. TVA and Duke need to build better transmission to prevent future outages and grid-scale failures, Mahan said.

TVA and Duke Energy both had major power outages about the same time on Dec. 24, Mahan said. He added that both imported significant amounts of power from organized wholesale markets to avoid a more dire situation.

Duke reached its highest emergency level and initiated rolling outages that same day. Mahan noted North Carolina's northeastern corner remained stable because it is in the PJM footprint.

"While much of the state was under rolling blackouts, that corner of the state was not experiencing blackouts," he said.

TVA at times imported more than 5 GW from MISO on Dec. 23 and 24, Mahan said. Those exports helped trigger the RTO's own maximum generation event, setting off stakeholder debate on how far it should stretch its system to assist neighbors. (See *MISO Actions During December Storm Spark Debate*.)

Duke Energy solar generation construction | *Duke Energy*

According to the North Carolina Utilities Commission (NCUC), Duke was negatively impacting the entire Eastern Interconnection's frequency on Dec. 24. Mahan said Duke was close to setting off "significant and widespread" outages like the 2003 Northeastern blackouts.

"The situation was really quite dire before they decided to start causing the rolling blackouts," Mahan said.

Duke Carolinas under-forecasted demand by as much as 1.5 GW on Dec. 24, while Duke Energy Progress East had an even larger forecast gap at 2.8 GW, Mahan said.

The bitter cold proved "really difficult for the company to come back from," he said, noting that Duke was not able to resume normal operations until nearly midday Dec. 26. Had it not been for solar generation's strong performance on Dec. 24, Mahan said, Duke would have been thrown further into "dire straits."

He said after analyzing preliminary import and export data from the Energy Information Administration, the Southeast region's system may have been "so taxed and so overburdened" that loop flows materialized.

Mahan said state regulators should investigate the event and make findings public. "We need to get a better sense of what actually happened," he said.

Mahan said the region had indications that its grid and thermal generation would struggle during the storm. He said the wave of intense cold Dec. 23-24 fulfilled predictions meteorologists forecasted a week earlier.

"We should have been more prepared. We've seen it before. It's happened before," he said.

Mahan said the main difference between the two recent winter storms is that the December event had a "more direct bullseye" on the Southeast. He said he hoped more attention is paid this time to actionable changes.

Mahan said the Southeast needs more regional and interregional transmission connections; it's imperative, he said, that Duke and TVA

Southeast

also diversify their generation mixes by adding more wind, solar and battery storage than natural gas plants.

Duke and TVA would have benefitted from larger solar fleets in this instance because sunshine was surprisingly plentiful during the event, Mahan said. He said as fossil plants struggled to be available on Christmas Eve, more solar generation would have shortened the length of the blackouts or made the outages less severe.

Chris Carmody, executive director of the Carolinas Clean Energy Business Association, said Duke would be better served if it "connects with a pack of states next door who don't have blackouts."

Duke Energy Carolinas CEO Julie Janson appeared before the NCUC on Jan. 3 to apologize and vow the utility would learn from the experience.

"We own what happened," she said. "We have set out on a path to ensure that if we are faced with similar challenges, we will see a different outcome and provide a better customer experience."

Duke spokesperson Jeff Brooks told *RTO Insider* that the company "employed thousands of megawatts" during the storm. He said solar was added when it became available, but that it "was not generating at the time temporary outages were required as the sun was not up."

Brooks said resources that Duke was counting on "included deliveries of generation from independent power producers and purchases through our out-of-state interconnections that were not fulfilled for use on Dec. 24 due to other utilities experiencing the same challenges."

He said RTO membership "would present more risks than benefits to our customers and our state."

TVA has launched an internal investigation of its actions and has also pulled together an independent, three-person panel to separately review how it can better prepare for severe weather. The panel includes American Public Power Association President Joy Ditto; Mike Howard, former CEO of the Electric Power Research Institute; and former U.S. Sen. Bob Corker (R-Tenn.).

"This is not the way we want to serve our communities and customers," TVA said in a press release late last month.

TVA said it had nothing more to add when *RTO Insider* requested a reaction to SREA's recommendations.

Mahan said the Southeastern Energy Exchange Market (SEEM) didn't appear to assuage the situation like an RTO could have.

"There should have been more willing purchasers on Dec. 23, but the market showed that it had even less purchases from the day before," he said.

In fact, Mahan said that SEEM's records showed no voluntary trades of excess power Dec. 24-26. He said that was "highly unusual," but that it's difficult to get a sense of what happened because SEEM isn't a transparent operation.

"It wasn't helpful at all for many days, which was very unfortunate," Mahan said.

"It's designed to do so little in the first place. There's just not much to it," Carmody said of SEEM's structure. ■

CAISO/West News

Panel Sees Vital Role for Calif. Offshore Wind

By Elaine Goodman


David Hochschild, CEC | *Stanford University*

As Californians ponder how the state can achieve a 100% clean energy future while maintaining electric reliability, the chair of the California Energy Commission last week offered a two-part solution.

"Offshore wind coupled with storage is how we do that," CEC Chair David Hochschild said. "Those two things to me go hand-in-hand."

Hochschild's comments came Jan. 23 during an offshore wind webinar hosted by the California Natural Resources Agency. One listener asked Hochschild if there's a guarantee that the state will stop using "the dirtiest forms of energy" once offshore wind is deployed.

Hochschild noted that state law requires all electric retail sales to come from renewable and zero-carbon resources by 2045. At the same time, he said, "the paramount issue is reliability."

The CEC chair spoke enthusiastically about offshore wind, which he said could power a home for a day with a single turbine rotation.

"In my judgment, after rooftop solar, offshore wind is the lowest-impact form of electric generation in the world," Hochschild said. And offshore wind is "highly aligned" with the late afternoon and early evening hours when power is most needed, he said.

The webinar was moderated by Natural Resources Secretary Wade Crowfoot as part of his *Secretary Speaker Series*. Crowfoot said more than 500 people tuned in to the session.

Optimizing Locations

For California offshore wind, floating turbines would be 20 to 30 miles off the coast — a location with potential environmental advantages.

"We are very pleased … that this floating technology is able to push projects 20-plus miles from shore," said webinar speaker Kristen Hislop with the Santa Barbara-based Environmental Defense Center. "Many environmental groups are very concerned about projects closer to shore."

Hislop said the nonprofit is optimistic about offshore wind's potential to help California fight climate change, reduce air pollution and improve energy reliability. At the same time, she said, choosing offshore wind sites should consider species and habitat data and not just wind speed and technical considerations.

"We don't want to see projects inadvertently impact migrating whales, birds and bats, sea turtles, sharks, fishes and other animals that rely on the California coast," Hislop said.

Another webinar speaker was state Sen. John Laird (D), whose Central Coast district includes the site of the Diablo Canyon nuclear power plant.

Laird said he took part in negotiations over postponing the retirement of Diablo Canyon's two reactors, which had been planned for 2024 and 2025. The state is now eyeing a 2030 closure date for the plant.

"I helped fashion that deal in a way that if there was going to be an extension, it would be just extended to the time that offshore wind was coming on, so that we could transition the transmission in that area to use [for] the offshore wind," Laird said.

First Auction Completed

Last month, the U.S. Bureau of Ocean Energy Management held an offshore wind auction for five leases off the Northern and Central California coasts. The auction, the first for the West Coast, brought in $757 million from the five winning bidders combined. (See *First West Coast Offshore Wind Auction Fetches $757M*.)

The five lease areas — three off the Central Coast in the Morro Bay Wind Energy Area and two off the Northern California coast in the Humboldt Wind Energy Area — have a total capacity of up to 4.6 GW.

That's far short of the state's goal of 25 GW of offshore wind capacity by 2045, and some are already thinking about the next auction.

"We need to move quickly to develop siting plans for the next set of call areas," said Adam Stern, executive director of Offshore Wind California, an industry coalition.

Stern pointed to planning areas off the coast of Mendocino and Del Norte counties, saying there's potential for another auction within two years. He said stakeholder involvement is crucial.

"It's critical that all of the constituencies that are represented on this call are part of this discussion," Stern said.

That theme was emphasized throughout the webinar.

"How do we get this done as quickly as climate change demands?" Crowfoot said in recapping the offshore wind conversation. "But in a way that's actually inclusive and thoughtful and careful to avoid and mitigate impacts." ■

Changes in California Energy Leadership Continue

By Hudson Sangree

A trend of job changes and departures in California's three major energy agencies has continued during the past two months, as officials opted to leave CAISO, the Public Utilities Commission and the Energy Commission, allowing Gov. Gavin Newsom to appoint replacements.

Ashutosh Bhagwat | *UC Davis School of Law*

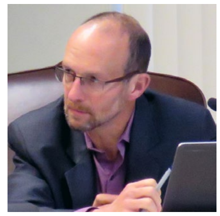
At CAISO, Governor Ashutosh Bhagwat opted not to seek another term after 12 years of service. Bhagwat chaired the Board of Governors last year; his most recent term ended Dec. 31.

"It has been a truly fantastic 12-year run, like nothing else I've had in my life," Bhagwat said during the board's last meeting of the year Dec 15. "I've enjoyed it thoroughly."

The University of California, Davis, law professor plans to leave the board by the end of February or as soon as Newsom names his successor.

At the CPUC, Commissioner Clifford Rechtschaffen chose to leave when his six-year term ended in December. Former Gov. Jerry Brown appointed Rechtschaffen, his senior adviser on climate and energy issues, to serve on the CPUC in January 2017.

"My term at the CPUC was very rewarding, but I just turned 65, and I'm ready to move on to the next phase in my professional life, including doing some teaching again," Rechtschaffen, a former law school professor at Golden Gate University School of Law in San Francisco and graduate of Yale Law School, said in an email to *RTO Insider*.



Clifford Rechtschaffen | *© RTO Insider LLC*

Karen Douglas | *CEC*

On Dec. 22, Newsom said he was appointing Karen Douglas, his senior energy adviser and former member of the CEC, to fill the open CPUC seat left by Rechtschaffen.

A month later, Newsom's office announced that CEC Commissioner Kourtney Vaccaro had been appointed technical adviser to Douglas at the CPUC. Vaccaro had served on the CEC since March 2022. She previously worked as Douglas' top adviser at the CEC, where she had held multiple positions including chief counsel.

Kourtney Vaccaro | *CEC*

Newsom must next appoint a new CEC commissioner. The position requires confirmation by the State Senate, as do seats on the CAISO board and CPUC.

The series of personnel changes are similar to those that occurred in December 2021 and early 2022, when Newsom chose Douglas as his energy adviser, named Vaccaro to the CEC and appointed his senior energy adviser, Alice Reynolds, as the new CPUC president.

CPUC headquarters in San Francisco. | *© RTO Insider LLC*

Earlier in 2021, Newsom appointed CEC Deputy Director Siva Gunda as a commissioner and chose then-CEC General Counsel Darcie Houck to fill an open spot on the CPUC, after he selected CPUC Commissioner Liane Randolph to head the influential California Air Resources Board.

Once the latest round of changes is complete, all five commissioners of the CPUC, four of five CAISO governors and the majority of CEC commissioners will be Newsom appointees. The governor has sought to exercise control over the state's energy institutions with an aggressive climate agenda and efforts to keep the lights on following rolling blackouts ordered by CAISO in August 2020. ■

CAISO/West News

Wash. Bill Seeks to Accelerate Renewable Buildout

By John Stang

Sen. Joe Nguyen | *Washington State Democrats*

A catch-all bill to boost construction of renewable power in Washington picked up support ranging from conditional to strong at a hearing Jan 24.

Senate Bill 5380, introduced by Sen. Joe Nguyen (D), covers several subjects, including:

- Requiring environmental impact statements for hydrogen projects statewide and for solar projects in the Columbia River Basin. These projects currently go through a preliminary review that determines whether a full environmental impact study is needed.
- Speeding up the state Environmental Policy Act's process to prepare environmental impact statements, declaring they must be complete in two years or less.
- Creating a coordinating council among state agencies to improve cooperation in setting up clean energy projects. This would be different from the Washington Energy Facility Site Evaluation Council, which makes permitting recommendations to the governor. The new coordinating council's purpose would be to make project preparation work more efficient.

The bill would also require the Washington State University Energy Program to create a "least-conflict" siting process for pumped storage projects. Washington has one pumped storage project in the works, which is controversial because part of it would be on land that the Yakama Nation of Indians considers culturally sacred.

Rye Development of Boston, is hoping to build Washington's first pumped storage project for $2 billion in southern Klickitat County near the John Day Dam. It would be in operation between 2028 and 2030.

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 and the other at the top of a cliff. An underground pipe would connect the two 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 then would be pumped back up to the upper reservoir in a closed-loop system.

At last week's hearing before the Senate Environment, Energy and Technology Committee, which Nguyen chairs, the senator said the bill's purpose is to increase efficiency in setting up renewable energy projects. "We will not be able to meet our energy goals without more energy facilities," he said.

No opposition to the bill surfaced at the hearing. Meanwhile, support among 27 testifiers ranged from strong to tentatively neutral until some changes are made in the bill.

Labor and business interests liked the jobs that renewable energy projects would create.

Others wanted proposed wind, nuclear and solar projects outside the Columbia River Basin to be subject to the required environment impact studies without going through the preliminary reviews.

John Rothlin of the Avista Utilities said the bill needs more and clearer deadlines for the processes that it addresses. ■

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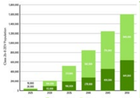

CARB Examining Obstacles on Road to ZEV Fleet Adoption — NetZero Insider

Tesla to Invest $3.6B in Nev. Truck, Battery Factories — NetZero Insider

CEC Awards $46M for ZEV Manufacturing — NetZero Insider

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CAISO/West News

PG&E Must Seek New Diablo Canyon License

By Hudson Sangree

The Nuclear Regulatory Commission told Pacific Gas and Electric last week it would have to file a new application to keep California's last nuclear generator, the Diablo Canyon Power Plant, operating beyond its planned closure dates in 2024 and 2025.

To expedite the renewal process, PG&E had asked the NRC to review a license application it filed 13 years ago. The NRC said it could not review the old application but would consider a waiver that might allow Diablo Canyon to continue operating as the commission weighs a new application.

PG&E said it had anticipated the decision and planned ahead.

"PG&E's project plan considered this regulatory path, and we have been developing application materials and supporting documents to support a filing with the NRC later this year," the utility said in an emailed statement.

PG&E filed its previous renewal application in 2009 but withdrew it in 2018, based partly on the determination by state officials that the plant would not be needed to meet future demand for electricity.

Circumstances changed, however, as the state faced energy emergencies during the past three summers including rolling blackouts in 2020 and near misses in 2021 and 2022.

Amid the crisis, Gov. Gavin Newsom and state lawmakers took steps to retain Diablo Canyon's 2.2 GW of baseline power until at least 2030, and the U.S. Department of Energy awarded PG&E $1.1 billion to keep the plant open. (See *DOE Grants PG&E $1B for Diablo Canyon Extension.*)

In October, PG&E asked the NRC to review its prior application and offered to supply updated information as needed.

The NRC denied the request in a Jan. 24 *letter* to PG&E.

"The NRC staff has determined that resuming this review would not be consistent with our regulations or the [NRC's] principles of good regulation and that there is no compelling precedent to support your request to resume the review of your withdrawn application," the letter said.

"This decision does not prohibit you from resubmitting your license renewal application under oath and affirmation, referencing information previously submitted, and providing any updated or new information to support the staff's review," it said.

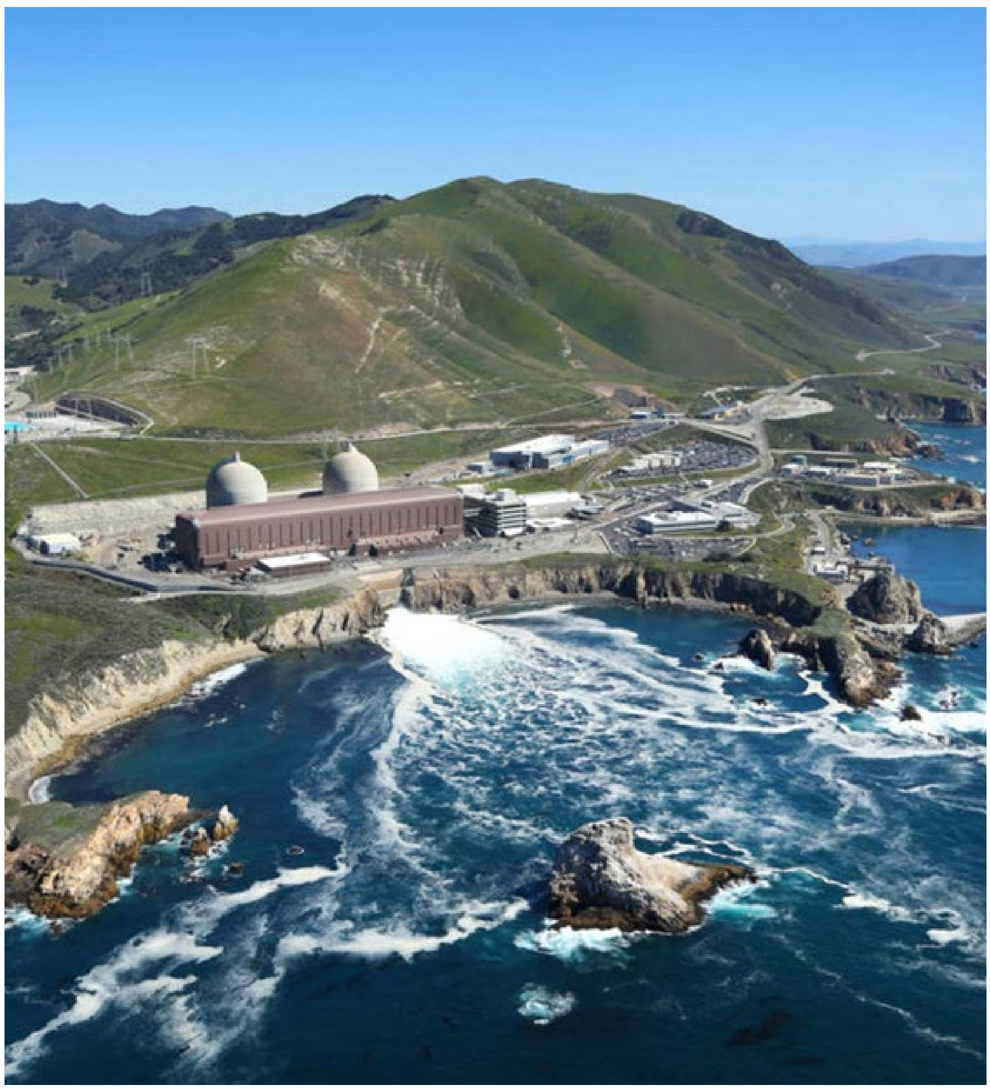
PG&E had also asked for a waiver under a federal regulation that allows a nuclear plant to keep operating past its license expiration date if it files a renewal application at least five years before the existing license expires. In that case, the "existing license will not be deemed to have expired until the application has been finally determined," the regulation, 10 CFR 2.109(b), says.

PG&E asked the NRC for a waiver of the rule's time requirement if it submitted a new application by Dec. 31, 2023. The current operating licenses for Diablo Canyon's units 1 and 2 expire in November 2024 and August 2025, respectively.

PG&E's waiver request remains under NRC review.

"The NRC staff has not made a determination on your request for an exemption from 10 CFR 2.109(b), which is included in your October 31, 2022, letter," it said. "The NRC staff is evaluating that exemption request and expects to provide a response in March 2023."

PG&E said in a statement that NRC's decision had "clarified the regulatory path PG&E will follow regarding the license renewal application (LRA) process, while allowing the company to leverage work already reviewed in our 2009 LRA. PG&E intends to submit a new application by the end of 2023." ■



The Diablo Canyon nuclear plant sits on a scenic stretch of California's central coast. | *PG&E*

ERCOT News

ERCOT Technical Advisory Committee Briefs

Staff Working to Understand Forced Outages in December Storm

ERCOT told its stakeholders last week that it is gathering information from its generators about the high number of outages during the December winter storm.

Staff told the Technical Advisory Committee during its Jan. 24 meeting that they have sent requests for information and its weatherization teams to generator resources that suffered forced outages during the Dec. 22-24 event. Thermal outages peaked around 13 GW, and gas supplies were again curtailed as an unwelcome reminder of the deadly February 2021 winter storm that killed hundreds of Texans and caused billions in economic damages. (See “ERCOT: December Storm ‘Non-event’,” *PUC Closes in on ERCOT’s Market Redesign*.)

Dan Woodfin, vice president of system operations, promised a more comprehensive report, saying staff are combining the information from the RFIs and will analyze the more detailed information.

Saying that ERCOT’s outage scheduler tends to understate outages, Independent Market Monitor Carrie Bivens asked Woodfin whether staff intended to do a true-up with telemetered values.

“Our intention is to look at telemetry and values, the outage scheduler and the results of the RFI, and kind of put it all together,” he said.

ERCOT’s *preliminary analysis* found gas restrictions in North Texas and operational flow orders issued to prevent gas flowing beyond contract maximums resulted in some curtailments and generation capacity. It also found that reduced renewable generation was not a large factor during the event.

Load peaked at 73.96 GW on Dec. 23, a 16-GW increase from ERCOT’s previous December record. The grid operator’s models projected a nearly 71-GW peak as the storm approached. Woodfin said other grid operators had similar problems predicting load, but that ERCOT’s miss had little effect on market reliability.

NRG Energy’s Bill Barnes took exception to the remark.

“You’re always going to get some type of market response based on ERCOT’s forecast. We look at it as a really big input into our decision-making,” he told Woodfin. “When there’s an under-forecast, that will probably result in a lower offer into the day-ahead [market], which is an economic commitment, which would mean you would have to take other additional [out-of-market] actions. The response that you get from the market? A lot of that comes from ... what you guys think.”

Dan Woodfin's staff is analyzing forced outage information from the December storm. | *© RTO Insider LLC*

Staff plan to engage with TAC’s Wholesale Market Subcommittee on the forecast error.

ERCOT deployed nearly 2.7 GW of its new firm fuel supply service (FFSS) Dec. 22-25 during the event. However, it *failed to notify* all market participants of the deployment or recall, as required under its protocols, and staff made system changes in January to correct the error.

Staff are drafting *new protocols* to improve existing language as they prepare for the next FFSS obligation period later this year. The changes are expected to improve the process for approving or instructing the restocking of fuel; offer disclosure reporting; incorporate an alternative FFSS resource concept; and improve qualified scheduling entities’ (QSEs) process for FFSS testing.

RUCs Continue to Increase

ERCOT staff’s *annual report* on reliability unit commitments led some stakeholders to call for market-based solutions after a second consecutive year of heavy RUC usage.

The grid operator said 8,244.8 instructed RUC resource-hours in 2022 resulted in 7,910.5 effective hours. That was up from the 3,853.1 effective resource-hours in 2021 and a significant increase from the two years prior, when a total of 421.8 effective resource-hours were deployed.

The increased usage is a result of ERCOT’s reliance since the 2021 winter storm on a conservative operations posture that maintains more reserves sooner. Bivens told lawmakers last year that the practice could add more than $1 billion to customers’ bills in 2022.

“We have a giant increase in RUCing some really old generators,” David Kee, CPS Energy’s director of energy market policy, told staff. “It’s causing some concerns in my shop, and we’re thinking about what we’re doing to these generators. ... We’re basically running them into the ground. The more you lean on these generators and bring them online for reliability reasons, you’re going to find they’re going to break.”

ERCOT’s Dave Maggio said the average age of RUCed units was between 40 and 60 years. More than 87% of the effective

ERCOT News

resource-hours addressed capacity concerns, with 12.9% needed for local thermal congestion or voltage concerns; all of 2020's RUCs were used to meet local congestion or voltage issues after a hurricane damaged transmission facilities in the Rio Grande Valley.

Pressed on staff's "desire" to reduce RUCs, Kenan Ögelman, vice president of commercial operations, agreed there is a "potential better approach to procuring coverage for the uncertainty that we are dealing with."

Ögelman said the grid operator expects to continue conservative operations but will be "looking at" modifications or improvements to RUCs. A long-term, market-based solution focused on revenue adequacy resides at the Public Utility Commission, he said, but priorities have yet to be established.

ERCOT paid out $34.11 million in RUC make-whole payments last year that was almost exclusively covered by capacity-short charges. It also clawed back $24.85 million. Those numbers were $404,000 and $484,000 in 2020, respectively.

Staff also said the delayed real-time co-optimization (RTC) project will be brought before the Board of Directors in June after they perform due diligence on the market mechanism favored by the Independent Market Monitor and many market participants.

ERCOT's Matt Mereness said the project, put on hold almost two years ago after the 2021 winter storm, still has a $51.6 million budget line item and a three-and-a-half-year timeline "because we haven't revisited it."

The RTC tool would expand ERCOT's real-time market by clearing energy and ancillary services every five minutes, as most other grid operators already do. The PUC in 2018 directed ERCOT to add RTC in 2018; it opened a rulemaking in December 2020 for its implementation (*51588*).

The project's impact analysis will have to be revisited because of inflation's toll. Staff will also reassess its scope with an eye of resuming RTC work in July.

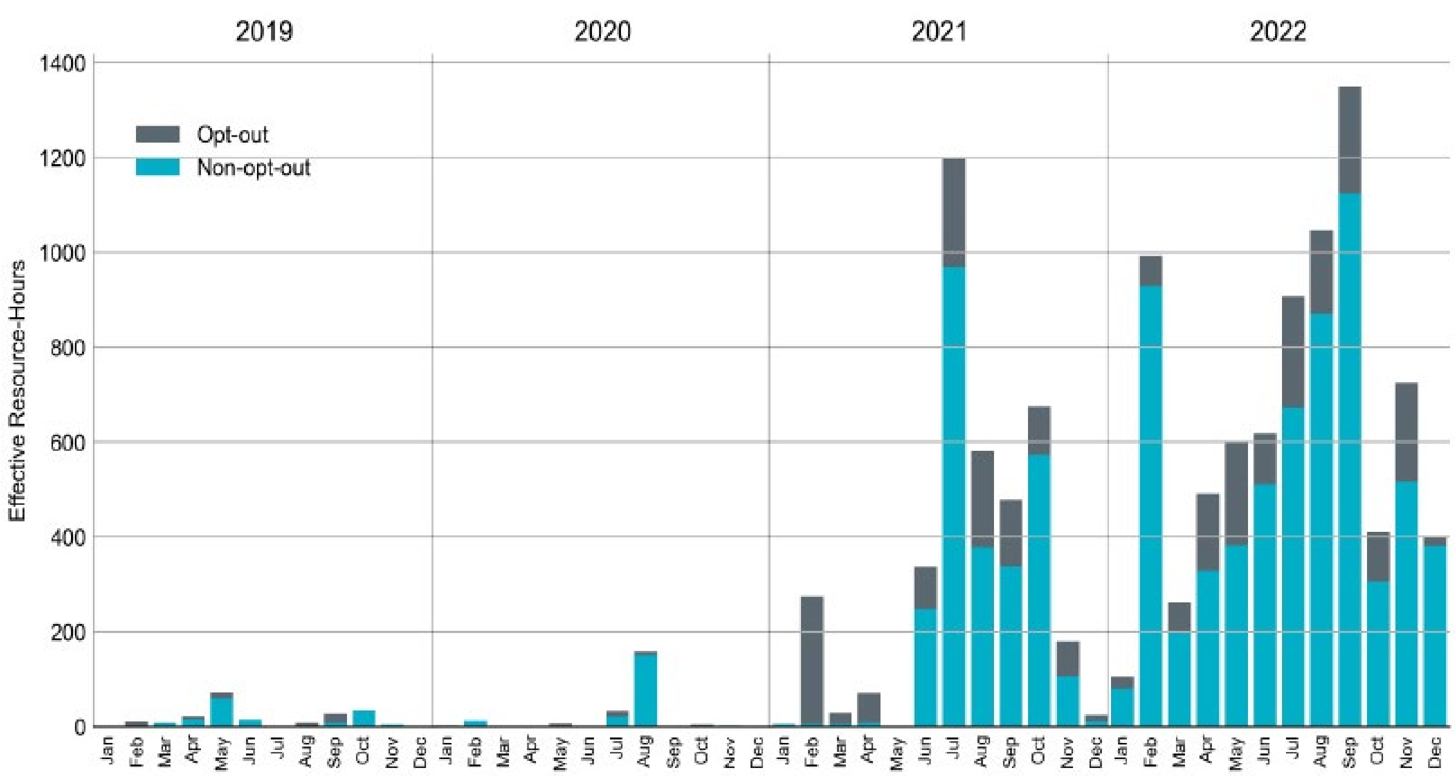
"From a reliability perspective, it's the next thing that we really do need," Mereness said. "We're not blind to the risk of this project of getting going, but we also know that we need to move forward on it. The reality is there are things going on at the commission. As that work [for ERCOT] comes out, it will have to be prioritized with other work."

Subcommittee to Charter Credit Group

TAC delegated the soon-to-be-disbanded Market Credit Working Group (MCWG) to develop a proposed charter, structure and name for a new working group that will report directly to the committee. The group will then replace the MCWG, which had provided input on credit-risk management issues to TAC's Wholesale Markets Subcommittee.

The stakeholder group will give market participants a voice in market credit issues after the board's Reliability & Markets Committee determined that staff should report to it on credit issues, and it moved in December to *disband* the Credit Working Group (CWG). The group was shifted last year to the R&M's purview from the Finance & Audit Committee, where it had been since 2004. (See "ERCOT Gets 1st Adjunct Member," *ERCOT Board of Directors Briefs: Dec. 19-20, 2022*.)

Speaking for Reliant Energy Retail Services, Barnes, a regular CWG attendee, pushed for the new group to include credit professionals, saying his company's credit pro recommended a voting structure. Other members stressed the importance of market diversity within the group.



ERCOT's RUC-instructed effective resource-hours have jumped over the last four years. | *ERCOT*

ERCOT News

The new group's responsibilities will likely include a credit review of all future nodal protocol revision requests, as required by *NPRR1157* and formerly carried out by the CWG.

TAC Elects 2023 Leadership

Committee members re-elected by acclamation South Texas Electric Cooperative's Clif Lange as their chair for 2023. Having recently been promoted as the cooperative's general manager, Lange has asked that TAC meetings be moved to Tuesdays this year.

Members also elected Jupiter Power's Caitlin Smith as vice chair. American Electric Power's Richard Ross also ran for the position.

The committee's 2023 subcommittee leadership was approved as part of the combination ballot:

- Protocol Revision Subcommittee (PRS): Martha Henson (Oncor) as chair and Diana Coleman (CPS Energy) as vice chair.
- Retail Market Subcommittee: Deborah McKeever (Oncor) as chair and John Schatz (Luminant) as vice chair.
- Reliability and Operations Subcommittee: Chase Smith (Southern Power) as chair and Katie Rich (Golden Spread Electric Cooperative) as vice chair.
- Wholesale Market Subcommittee: Eric Blakey (Pedernales Electric Cooperative) as chair and Jim Lee (CenterPoint Energy) as vice chair.

Most of the leadership are holdovers, with McKeever and Schatz switching positions. Coleman, Blakey and Lee are all new to their roles.

Members Endorse Five NPRRs

TAC unanimously approved *NPRR1144*, which provides a limited exception to the requirement that loads included in an ERCOT-polled settlement (EPS) metering facility's netting arrangement only be connected to the grid

Jupiter Power's Caitlin Smith and South Texas Electric Cooperative's Clif Lange take their leadership seats for TAC. | *ERCOT*

through the facility's metering point(s). The exception would allow no more than 500 kW of auxiliary load connected to a station service transformer be connected to a transmission or distribution service provider's (TSP/DSP) facilities through a separately metered point using an open transition load transfer switch listed for emergency use.

The measure passed 29-0, with CenterPoint abstaining.

TAC unanimously endorsed four other NPRRs on a combination ballot with a change to the Planning Guide (PGRR) that, if approved by the board, would:

- *NPRR1147*: set fast frequency response's ancillary service offer floor 1 cent/MW lower than other responsive reserve services categories to allow FFR's procurement up to the current limit, without proration with other categories.
- *NPRR1149*: charge QSEs an ancillary service failed quantity if their supply responsibility is not met in real time by their portfolio's resources, based on a comparison of their real-time telemetry.
- *NPRR1151*: eliminate the protocol requirement that the PRS hold at least one meeting per month.
- *NPRR1153*: add two existing fees (public information request labor and ERCOT training) to the grid operator's fee schedule; create a $500 registration fee for resource entities, TSPs and DSPs, and subordinate QSEs; delete the system administration fee's current value and the map sales fee; and restructure existing fees for generator interconnection or modification, full interconnection study applications and wide area networks.
- *PGRR102*: require resource entities and interconnecting entities to provide operations dynamic model quality test results that demonstrate appropriate performance for submitted operations dynamic models, and make non-substantive clarifying changes.

— Tom Kleckner

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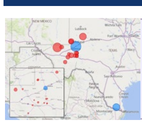
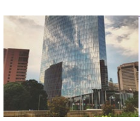


ERO Praises ERCOT's Actions to Address Inverter Incidents

ERO Insider



SERC Hits Virginia Electric with $320k in Penalties

ERO Insider

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ISO-NE News

New England States Unite in Push for Federal Transmission Funding

By Sam Mintz

The New England states have united to seek federal funding to help strengthen the region's transmission to accommodate electricity from offshore wind projects and Canada.

As a *coalition*, the states have put forward concept papers to the U.S. Department of Energy, asking to be considered for funding for transmission projects as part of DOE's new Grid Innovation Program, which is giving out up to $2 billion in funding in its first cycle.

The *program* will eventually give out up to $250 million per project, aiming to "support projects that use innovative approaches to transmission, storage and distribution infrastructure to enhance grid resilience and reliability."

New England's states see themselves as strong candidates, pointing to the region's unique energy security risks and natural gas reliance.

In a joint press release, the states said they are looking to pursue transmission investments that "reduce the region's reliance on imported fossil fuels in winter months, help insulate electricity customers from the wild swings in the fossil fuel markets currently leading to high electricity prices throughout New England and take advantage of diverse energy sources."

Their first proposal is a partnership between states, transmission providers and wind developers called the Joint State Innovation Partnership for Offshore Wind. If given federal funding, it would "proactively plan, identify, and select a portfolio of transmission projects needed to unlock the region's significant offshore wind potential, improve grid reliability and resiliency, and invest in job growth and quality."

In a separate submission led by Vermont, the states are also asking DOE for funding for the *New England Clean Power Link*, a proposed 1,000-MW transmission line between Québec and Vermont that would increase imports of Canadian hydropower.

The NECPL, under development by Blackstone subsidiary TDI New England, has received the permits it needs to bury two six-inch wide cables for around 150 miles in Vermont, including under Lake Champlain. But there's no contract yet for the power that would be delivered, and construction on the project has yet to commence.

DOE will be evaluating the applications over the next few weeks and is expected to invite some of the applicants to submit full proposals for funding, which would be due in May.

"We are hopeful that DOE views these concept papers favorably, and Connecticut and its partners stand ready to turn the proposals we've submitted into tangible models of climate action and its numerous benefits," said Katie Dykes, commissioner of the Connecticut Department of Energy and Environmental Protection. ■

The New England states are grouping together to ask DOE for major federal funding for transmission projects in the region. | *© RTO Insider LLC*

ISO-NE News

Comments Show Battle Lines over ISO-NE Interconnection Costs

By Sam Mintz

Transmission owners in New England have asked FERC to dismiss a RENEW Northeast complaint that seeks to shift the burden of network upgrade operations and maintenance costs off interconnection customers.

In the *complaint*, the renewables group argued that ISO-NE is the only U.S. region in which interconnection customers are directly assigned costs for the capital and O&M needed for network upgrades, an "exemption" from FERC policy that RENEW said is unjust and unreasonable. (See *Renewable Group Asks FERC for Interconnection Cost Changes in NE*.)

In its *response*, ISO-NE asked to be dismissed from the complaint because the provisions under discussion are transmission rate terms under control of the transmission owners and in which the grid operator doesn't hold any financial interest.

The transmission owners offered a *more substantive* answer, arguing that the complaint "fails to meet RENEW's [Federal Power Act] Section 206 burden of proving that the tariff rate on file is unjust and unreasonable."

The TO's argue that generators paying for network upgrades is part of a "grand bargain" that also includes "free and unlimited open access to regional network transmission service on the ISO-NE system."

It's a deal that has been subject to FERC review several times and been repeatedly accepted by the commission, the TOs wrote.

They also argue that altering a single aspect of cost allocation for the region's system could place the entire structure in "jeopardy," which is why FERC has a "stated policy against unilateral changes to a single aspect of a comprehensive negotiated rate structure."

Other Corners Respond

New England's generators, unsurprisingly, backed the RENEW complaint.

The New England Power Generators Association (NEPGA) described in its *comments* the "negative impact this unlawful assignment of O&M costs has on competitive market outcomes." NEPGA noted that market participants can't recover the O&M costs in the capacity or energy markets.

"The shifting of costs RENEW highlights creates broad negative economic consequences both for resources that rely on markets to produce economic outcomes and those that pay for their services," the association wrote.

Likewise, in a joint comment, the renewable and clean energy groups Advanced Energy United and the Northeast Clean Energy Council supported RENEW's complaint, saying the direct assignment charges at issue "unduly burden interconnection customers" that are currently most heavily represented by renewable and storage developers.

"Directly assigning O&M network upgrade costs to interconnection customers clearly violates FERC's O&M cost policy and the 'beneficiary pays' rule of cost allocation and should not be sustained," the groups wrote.

Among those weighing in against the RENEW complaint were the New England states (as represented by New England States Committee on Electricity) and newly appointed Massachusetts Attorney General Andrea Campbell. Both argued that the complaint would shift costs unfairly onto ratepayers.

"RENEW seeks to replace long-settled rules that put development risks and costs on interconnection customers with a one-sided bargain that shifts 100% of those costs to consumers," NESCOE wrote in its *comment*. "The commission should reject that myopic approach, as both bad policy and a matter of law."

Campbell's *comment* pointed to precedent, including past commission rulings and failure of a similar proposal in the NEPOOL process, to argue against the complaint in addition to expressing worries about the costs for consumers.

"New England ratepayers ... already pay higher transmission costs than customers in any region in the United States," the AG wrote. "To grant RENEW's cost shifting remedy would only exacerbate New England ratepayers' already high transmission rates." ■

All corners of the New England sector debated interconnection cost allocation in comments this week. | *© RTO Insider LLC*

ISO-NE News

NH Lawmakers Want to Take a Look at Leaving ISO-NE

By Sam Mintz

Should New Hampshire leave ISO-NE?

A group of six Republican state lawmakers is putting forward a *bill* that would create a commission to study that question.

The commission would investigate whether it would be feasible for the state to withdraw from ISO-NE and become its own independent grid operator, market administrator and power system planner.

In a hearing of the Science, Technology and Energy Committee on Monday, the primary sponsor Rep. J.D. Bernardy (R) said that costs to consumers are what's motivating his effort to consider separating from New England's grid.

"In my campaign, one of the key issues I faced was explaining to constituents why there were skyrocketing costs of electric power," he said during an informational hearing.

If New Hampshire — a net exporter of power to the rest of the region — were to withdraw from ISO-NE, it could harness the electricity produced in-state to power its own economy and households, he argued.

"Peak power in New Hampshire is a little over 2,000, 2,100 MW. What does Seabrook [Nuclear Power Plant] produce? About 1,200. That's about 60% of the power for New Hampshire," Bernardy said.

The proposal was met with significant skepticism by the other members of the committee, who noted that Seabrook's power is contracted out to buyers in a number of other states and couldn't necessarily be contained to New Hampshire.

Other committee members also pointed out that there would be immense legal and logistical challenges associated with separating from the regional grid operator.

"By withdrawing from the ISO, we would be blowing a big hole in the regional power system," Rep. Tony Caplan (D) said.

And, he asked, "how would we be able to provide lower rates for New Hampshire ratepayers given that the administration and regulation and all those services we would have to provide ourselves?"

Maine and Connecticut have both taken on similar assessments — Maine in 2007-8 and Connecticut in 2020 — and neither decided to move forward, said Joshua Elliott, director of the division of policy and programs at the New Hampshire Department of Energy.

Elliott said the agency is neutral on the bill because it would only involve studying the subject. If the legislature does move forward with the proposal, he suggested that it consider recruiting consultants to help put forward a more "substantive" end product.

The other sponsors of the bill are Republicans James Summers, Susan Porcelli, Fred Plett, Jason Janvrin and Yury Polozov. ■

New Hampshire lawmakers are calling for a study into whether the state should leave ISO-NE. | *Shutterstock*

MISO News

DC Circuit Upholds FERC's Refund Order in Ameren Illinois Case

By James Downing

A three-judge panel of the D.C. Circuit Court of Appeals on Jan. 24 upheld FERC's decision requiring Ameren Illinois to refund inappropriately recovered costs related to transmission construction.

The utility improperly included costs for construction-related supplies and materials in the same filing that was meant to recover the cost of transmission plant materials and supplies, when the construction supplies were not eligible to be recovered under the formula rates Ameren Illinois was using at the time.

"The commission found that Ameren Illinois had misreported materials and supplies costs on Form 1 and ordered Ameren Illinois to pay approximately $11.5 million in refunds to its customers, based on ten years of misreporting," the court said (*20-1277*).

Ameren filed for rehearing, which was rejected by FERC (ER20-1237). The company appealed to the D.C. Circuit, which said that FERC has broad statutory authority to grant refunds.

345-kV transmission line foundations | *Michels Power*

"Upon finding that Ameren Illinois failed to correctly record certain materials and supplies costs in the annual Form 1 report, the commission reasonably determined, based on a balancing of the equities, that refunds were warranted," the court said.

Ameren argued that FERC issued its customers a "windfall" and failed to perform a required balancing-of-equities test in granting the refund, but the court disagreed.

The utility said reporting construction-related costs in the wrong line was a common industry practice before FERC found Duke Energy Progress doing the same and put the industry on notice that it needed to stop the practice. That means it should not be bound its formula rate, Ameren said.

"No justification is offered for that position," the court said. "The utility's view that the misreporting was a mere technicality ignores the fact that such costs, if properly reported at line 5, could not have been passed on to customers under Ameren Illinois's formula rate."

Rather than giving customers a windfall, Ameren's error resulted in a windfall for itself to the tune of $11.5 million. That amounts to more than a ministerial error, the court said.

Just because FERC has not issued a refund order for every other utility that listed the construction-related costs under the wrong item does not mean the refund order to Ameren was unjust and unreasonable, the court said. ■

MISO News

MISO, Stakeholders Debate Lower Congestion Limit

System Impact Threshold Expected to Increase Network Upgrades

By Amanda Durish Cook

CARMEL, Ind. — MISO appears set to limit transmission congestion by instituting a lower system impact threshold on interconnecting generation that is all but certain to prompt more network upgrades.

"We've received a lot of feedback on this item," MISO's Kyle Trotter said during a Planning Advisory Committee meeting Wednesday. "We continue to believe that this change will bring positive impacts to stakeholders and future system reliability."

The RTO's proposal might dim prospects for some new generator interconnection requests. (See *MISO Insists it can Handle Record-setting Interconnection Queue*.)

Last summer, MISO suggested halving new generation's allotted distribution factor's (DFAX) effect on transmission from 20% to 10% for its basic and unguaranteed energy resource interconnection service (ERIS). (See *MISO Recommends Lower Distribution Factor to Address Congestion*.)

Trotter said the change will result in upgrade costs being shared among more interconnection customers and fewer unaddressed reliability issues being passed on to later queue cycles or surfacing in MISO's annual transmission expansion plans. He also said the likely additional upgrades will help reduce "future reliability issues and overloaded equipment."

The grid operator responded to a request from MISO South members and studied a 5% DFAX limit but decided the threshold would be too drastic. Staff said a 10% limit provides a good balance without being too aggressive.

Some stakeholders have said that it's premature to lower the DFAX threshold across the board when MISO hasn't yet put together a long-range transmission plan portfolio for the South region. Staff have marketed the LRTP portfolios as being able to support more generation interconnections.

Generation developers maintain that a tighter DFAX threshold is punitive and places even more responsibility for system planning on interconnection customers. Some stakeholders have argued that MISO is conflating transmission reliability with real-time congestion costs.

"The plan remains the same," Trotter said, adding that MISO will begin applying the change to the 2022 cycle of projects entering the definitive planning phase. The revision requires a change to MISO's business practice manuals.


Andy Witmeier, MISO | © *RTO Insider LLC*

Several stakeholders complained that staff haven't studied the possible financial impact to interconnection customers.

"This was sold as a way to reduce congestion," NextEra Energy's Matt Pawlowski argued. "I as a NextEra representative don't know what I'm actually getting with this change. No dollars have ever been shown. I know one thing: My costs are going to be higher. But I'm not sure what I'm going to get for that money. I would love to know what the plan is to actually show that."

Pawlowski said that the issue was introduced as an economic benefit, but MISO morphed it into a reliability matter.

Andy Witmeier, director of resource utilization, agreed that stakeholders initially raised the issue as an economic one. He said when staff examined the situation, it became clear that the RTO needed to act out of a concern for reliability.

"We're going to be adding three to four times more generation to our grid than is retiring. So, this is just going to continue. Our stance is that now is the time to make this change. We can't wait for all these units to come online," Witmeier said. "Certainly, there are economics at play here, but MISO's position has always been, 'This comes down to reliability.'"

"The problem is you've not proven anything," Pawlowski said. "We've conflated economics with reliability and come up with reliability because it's the easier one to pursue. And we're going to pay those extra dollars not knowing … whether we have better access to the grid. That hasn't been addressed."

Witmeier countered that MISO's reliability analyses of a tighter DFAX threshold turned up "a lot of constraints that we've been ignoring."

Union of Concerned Scientists' Sam Gomberg said MISO has not performed a cost-benefit analysis to show that a lower DFX cutoff would combat congestion.

"We don't know the impact of this change. All of the projects could withdraw, and none of these upgrades could be built," Clean Grid Alliance's Rhonda Peters said. "I'm not saying that's the case. I'm saying we haven't done an adequate study."

Peters said that MISO has not contemplated how much generation might drop out because of a 10% cutoff.

Travis Stewart, representing the Coalition of Midwest Power Producers, said the change means that the grid operator should update upgrade estimates for affected interconnection customers.

Witmeier said that IC customers, who consistently withdraw from the queue, should perform their own benefits analysis. He argued that the footprint doesn't currently have enough customers to buy all 280 GW of the generation in the queue.

"MISO is responsible for setting the reliability standards on congestion from generator interconnection. We're doing that," he said.

Sustainable FERC Project's Lauren Azar has maintained that lowering the DFAX threshold will result in more costs transferred to generators.

"Interconnection is about reliability and not addressing congestion," Clean Grid Alliance's Natalie McIntire argued during an October meeting of MISO's Interconnection Process Working Group. "What's resulting is congestion in real-time, which is an economic issue. ERIS generators are energy-only and should expect to be curtailed."

MISO staff contended at the time that the binding constraints interconnections ultimately cause are a reliability issue. They said potential constraints are currently being ignored in the GI process, only to crop up later in the system. ■

MISO News

MISO, SPP Update Stakeholders on Joint Tx Planning

By Amanda Durish Cook

CARMEL, Ind. — MISO and SPP said Thursday during their annual issues review that they plan to treat Joint Targeted Interconnection Queue (JTIQ) projects as large generator interconnection projects when allocating costs.

The RTOs have proposed allocating 90% of the portfolio's costs to interconnecting generators and the remaining 10% to their load. SPP's load will be responsible for 71% of costs, and MISO will shoulder the remaining 29%.

The JTIQ study completed early last year resulted in five projects on the RTOs' seam that should help reduce congestion and allow additional resources, primarily wind farms, to interconnect with their systems. The portfolio has an estimated cost of $1.06 billion. (See *MISO, SPP Propose 90-10 Cost Split for JTIQ Projects*.)

Sumit Brar, reliability analysis lead for MISO long-range planning, said the grid operators will not begin additional JTIQ studies unless the first portfolio has secured enough generation to cover most or more of its costs. Future studies will be conducted on a five-year horizon.

MISO expects the first JTIQ portfolio to support up to 28 GW of interconnecting generation on both sides of the seam.

MISO stakeholders expressed worry that the necessary amount of generation may drop out of the two IC queues, leaving load to handle the bag of costs. Some have also said a 90% cost assignment to interconnecting generation might not be fair.

They asked whether the RTOs might consider adding a cost cap on the per-megawatt charge or enact protections when generation requests drop out of the queue.

"Now, there will be dropouts, so we expect that," MISO Director of Resource Utilization Andy Witmeier said, adding that the RTO expects it will take "a few queue cycles" to get the lines nearly funded.

Witmeier said it's "unrealistic" to assume that the grid operators won't have enough willing generation developers to fully fund the projects.

"Eventually, enough generators will sign up, sign [generator interconnection agreements] in the region," he said.

The RTOs are proposing that generation be on the hook for a JTIQ per-megawatt cost when a project has a greater than 5% distribution factor on one or more facilities in the affected system and a greater than 1-MW impact on "at least one" JTIQ line.

Sumit Brar, MISO | © *RTO Insider LLC*

Steelhead Americas' Adam Solomon said the threshold was "ridiculously low" when compared to the large interconnection projects in the MISO queue.

MISO and SPP said they don't plan an interregional planning study this year, saying their plates are full memorializing the targeted market efficiency projects (TMEPs) work and preparing for an expected FERC notice of proposed rulemaking on interregional transfer capability. MISO said its planners are also working on the second tranche of its long-range transmission plan.

The grid operators are required to undertake a coordinated system plan every other year. Last year, the two performed a TMEPs study that failed to identify any small interregional projects. (See *MISO, SPP Unable to Find Smaller Joint Tx Projects*.)

Basin Electric Power Cooperative had asked the RTOs to study constraints in the Dakotas, and Ameren has requested an examination of chronically congested 161-kV lines and a transformer linked to a 345-kV line in Missouri.

DOE Funding for JTIQs Won't Affect Cost Allocation

MISO said Jan. 24 that potential Department of Energy funds will not affect a planned cost-sharing plan for the JTIQ projects.

The grid operators are collaborating with the Minnesota Department of Commerce and the Great Plains Institute to apply for funding from the DOE's *Grid Resilience and Innovation Partnerships* (GRIP) program. (See *DOE Opens Applications for $6B in Grid Funding*.)

The program requires that states affected by a project make the application process. Great Plains is organizing stakeholders and coordinating the multistage GRIP application process.

Brar said states with a JTIQ project are all involved. Funding will be granted to states based on the percentage of projects located within their boundaries.

The organizations sent a concept letter to DOE earlier in January. The department will inform applicants by Feb. 24 whether their projects are sufficient enough for a full application that would be due May 19. Approved GRIP projects could potentially be awarded a 50% project match. (See *SPP MOPC Briefs: Jan. 17-18, 2023*.) ■

NYISO News

NYISO Slaps NextEra for Lobbying for OSW Tx Projects

By John Norris

NYISO CEO Rich Dewey has rebuked NextEra Energy Transmission New York for attempting to "lobby" the grid operator to award it transmission projects to connect offshore wind projects to Long Island.

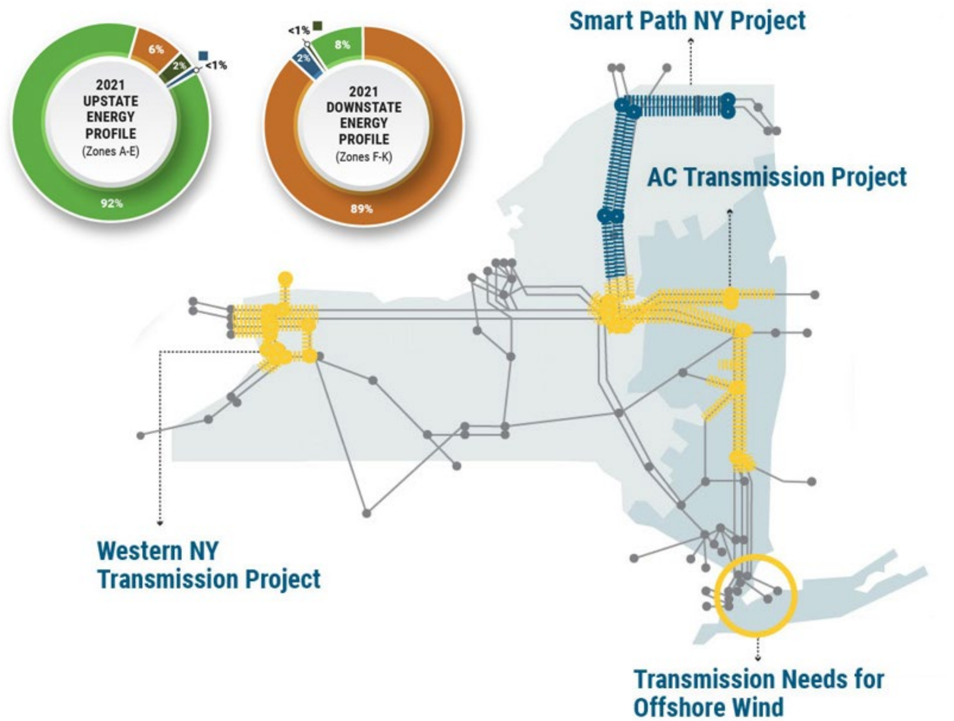
"The NYISO cannot, under its applicable rules, select a project based upon political, parochial or commercial interests," Dewey said in a Jan. 5 letter, which was first reported by POLITICO. "Grassroots lobbying efforts and media coverage are simply not part of the NYISO's evaluation of the more efficient or cost-effective solution" to the transmission needs identified by the Public Service Commission.

In August 2021, the ISO *solicited* projects to add "at least one bulk transmission intertie cable to increase the export capability of the [Long Island Power Authority]-Con Edison interface, that connects NYISO's Zone K to Zones I and J to ensure the full output from at least 3,000 MW of offshore wind is deliverable from Long Island to the rest of the state" and upgrades to associated local transmission facilities to accommodate the offshore export capability.

Of 19 proposals received from four developers, the ISO last April *identified* 16 "viable" projects, including nine from NEETNY's New York Renewable Connect. LS Power, Anbaric Development Partners and the New York Power Authority/New York Transco also made the short list.

NEETNY's *website* for the project includes seven "letters of support" from labor unions, elected officials and others.

The New York State Laborer's Organizing Fund, for example, *said* "NEETNY is the only potential developer that has actively reached out to the local labor communities where these lines will be constructed to pledge their commitment to good union jobs and involved us in their process."



New York's tale of two grids | *NYISO*

The "Western New York Delegation," which includes three state senators and two assemblymen, *praised* the company for its "extraordinary level of communication and capability" in building the 20-mile Empire State Line, the first competitively bid transmission project in the state.

None of the other competitors' project websites included such testimonials.

In an email to *RTO Insider*, Kevin Lanahan, NYISO's vice president of external affairs and corporate communications, said "the independence of the NYISO is paramount."

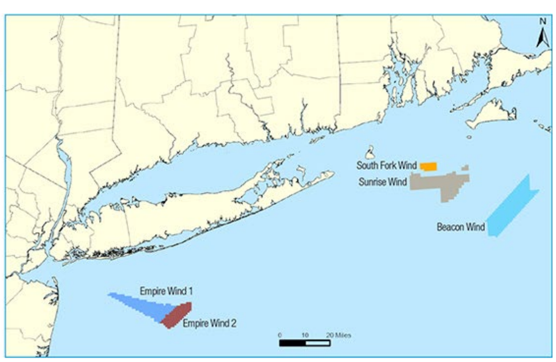
"This process, as with much of our work, requires that decisions are made according to an impartial analysis of facts and data, as stipulated in our tariff," and furthermore "the outcome is critical to the climate goals of the state and reliability of the power grid," which is why "when attempts to introduce outside influence into the decision-making process became apparent, we determined the prudent course of action was to remind all participants of the criteria being considered," Lanahan said.

After initially declining to comment, NEETNY told *RTO Insider* late Wednesday that it would comply with the ISO's rules.

"As with any project, we always reach out early to the local community and key stakeholders to explain the project need, gather feedback and establish an ongoing dialogue so that if our proposal is selected for construction, we can quickly begin engaging with local partners to incorporate their input," NEETNY President Richard Allen said in a statement.

"NextEra Energy Transmission New York is grateful to be a participant in the New York Independent System Operator's Public Policy Transmission Needs process, and we are committed to continue following the processes they have set forth." ■

Offshore Awarded Lease	Developer	MW	COD	POI
South Fork Wind	Orsted / Eversource	130	2022	East Hampton Substation
Sunrise Wind	Orsted / Eversource	880	2025	Holbrook Substation
Empire Wind 1	Equinor	816	2026	Gowanus Substation
Empire Wind 2	Equinor	1,260	2027	Barrett Substation
Beacon Wind	Equinor	1,230	2028	Astoria Substation



Long Island Offshore Wind Projects Under Development | *NextEra Energy*

NYISO News

Beacon Wind Draws Public Support at Power Line Hearing

NYPSC Continues Review of 1.2-GW Equinor-BP Project

By John Cropley

The proposed Beacon Wind I project drew unanimous public support last week during public hearings on the transmission line needed for the 1,230-MW wind farm planned off the New York coast.

The New York Public Service Commission held virtual comment sessions as part of its review process for the certificate of environmental compatibility and public need the developers must secure.

Many other state and federal approvals are needed before Equinor and BP can begin construction in 2025 in a 128,000-acre tract of ocean 60 miles east of the southeastern tip of Long Island.

The hearings Jan. 24 officially centered on the 115-mile underwater export cable running the length of Long Island Sound, plus a short overland cable and substation where it will make landfall in Astoria, Queens, in the northwestern corner of Long Island.

But everyone who spoke — activists, residents with no stated affiliation, business owners, and elected, union and neighborhood leaders — was in favor not just of permitting the cable but the entire project, and offshore wind in general.

The written comments submitted to the PSC were similarly supportive.

The level of public support for zero-emission wind power in and near the Astoria neighborhood is not surprising; the area has been dubbed Asthma Alley for its concentration of fossil fuel power facilities, past and present.

A subsidiary of NRG Energy had initially proposed to refurbish the Astoria Generating Station, a 558-MW peaker plant, prompting vigorous protests from neighborhood and climate activists.

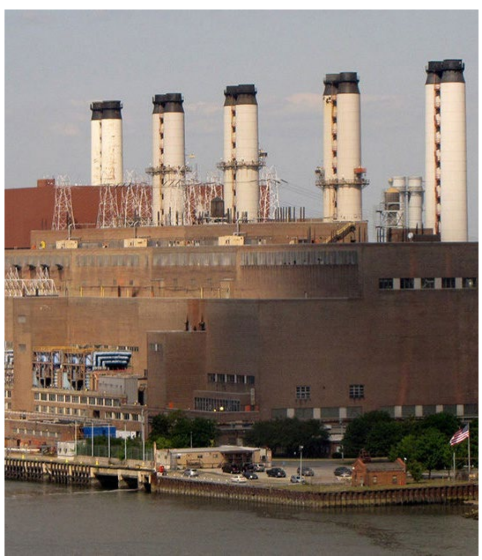
The state Department of Environmental Conservation rejected a plan to install a new 437-MW turbine generator on-site, saying it would not meet the emissions limits set in the Climate Leadership and Community Protection Act.

So instead, Astoria Gas Turbine Power opted to sell the site to Beacon Wind Land and demolish the power station.

Equinor told *RTO Insider* via email that the purchase of part of the complex is complete, and the developers would share more of their plans for the site in coming weeks.

Among the speakers last week:

- Casey Petrashek of the New York League of Conservation Voters said: "Beacon Wind I will bring significant environmental and economic benefits to New Yorkers."
- Kayli Kunkel, founder of the Earth and Me ecologically themed stores in Queens, said: "Clean, renewable energy and air and water quality are rights that we deserve as New Yorkers, and considering the diverse makeup of our borough, this is also an environmental and racial justice issue."
- Edwin Hill Jr., of the International Brotherhood of Electrical Workers, said the union appreciates Equinor's commitment to organized labor on the project. "Equinor has made a significant commitment of $52 million in social investments in New York state," he added.
- Fred Zalcman, director of the New York Offshore Wind Alliance, urged the PSC to grant the certificate of compliance and need. "The Beacon Wind project is a critical component of New York's nation-leading effort to power its economy based entirely on clean, renewable and carbon-free energy resources."



Public comment is running strongly in favor of replacing the Astoria Generating Station in New York City with a substation and point of interconnection for an offshore wind power cable. | *Ben Schumin, CC BY-SA-2.0, via Wikimedia*

- Marc Schmied, a volunteer with 350Brooklyn.org, contrasted the impact of constructing offshore wind farms with that of continued reliance on fossil fuel. "I understand and respect the concerns of both the local residents and the commercial fishermen who will be temporarily inconvenienced by the construction of Beacon Wind's transmission line," he said. "Offshore wind is by far the lesser of two evils here."
- State Assemblyman Zohran Mamdani, a Democrat who represents Astoria, said: "Our neighborhood has been on the front lines of the climate crisis but also on the front lines of fighting back, and last year we successfully beat back NRG's proposal to build a fracked gas power plant, and the approval of this permit will ensure that very same site that the plant would have been built will instead become an interconnection site."
- Richard Khuzami, representing the Old Astoria Neighborhood Association, said: "The Astoria waterfront, home to three major [public housing complexes] has long been afflicted by increased rates of asthma and other environmentally related afflictions, and this project will have a direct positive impact and improve quality of life."

Innovation Hub

As the developers push through the regulatory process, they are also taking steps to set up a supply chain, with construction of a tower manufacturing facility on the Hudson River in upstate New York and construction/support hub on the New York City waterfront.

Equinor and several partners Jan. 24 announced the opening of the Offshore Wind Innovation Hub in Brooklyn, which will help startups develop innovation in the offshore wind industry.

In a news release, Lyndie Hice-Dunton, executive director of the National Offshore Wind Research and Development Consortium, said, "We are delighted to be a part of this exciting partnership. The Accelerator Program is a unique opportunity to help support innovative solutions for offshore wind in the U.S., as well as help build strategic partnerships within this growing industry. We are looking forward to working with this outstanding group of leaders to achieve our mutual goal of accelerating offshore wind innovation." ■

NYISO News

NYISO Management Committee Briefs

CRIS Revisions Approved

NYISO's Management Committee on Wednesday approved the ISO's *proposed* tariff revisions related to the expiration and transfer of capacity resource interconnection service (CRIS).

The multiyear effort intends to enhance CRIS rules, with the objective of spending 2023 finishing the functional software requirements necessary to allow the ISO to track partial CRIS expirations.

The proposals seek to facilitate increased capacity deliverability by lowering the cost of new entry into the capacity market for an internal generator or an unforced capacity deliverability rights (UDR) facility looking to either transfer their CRIS rights to a same-location unit or expire their partial CRIS rights.

NYISO also adjusted the CRIS retention rules by enabling deactivated facilities to simply notify the ISO at any point that they will voluntarily relinquish their CRIS.

The Long Island Power Authority continued to object to the changes, saying they "do not address their concerns with CRIS expirations associated with interregional transmission ties with UDR," while three other organizations abstained from the vote. (See "CRIS Revisions Advance," *NYISO Business Issues Committee Briefs: Jan. 18, 2023*.)

The proposals now move to the Board of Directors for approval. NYISO anticipates filing the rules with FERC before the end of the first quarter.

NYISO control room in Rensselaer, N.Y. | *NYISO*

External and Virtual Transaction Errors

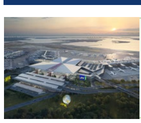
Sheri Prevratil, NYISO counterparty and credit risk manager, told stakeholders that the ISO identified typographical errors in the tariff language related to changes to credit requirements for external and virtual transactions, approved last year. (See "Credit Requirements on Virtual Transactions," *NYISO Management Committee Briefs: Nov. 30, 2022*.)

Prevratil said the two errors "changed one digit in the import supply table and one digit in the virtual supply table," though these "did not affect the analysis presented to the MC, and [the ISO has] already updated the presentation and tariff language" accordingly.

In response to a question from Howard Fromer, who represents Bayonne Energy Center, Prevratil confirmed that the tariff changes have not yet been filed with FERC and said NYISO intends to first seek board approval for them in February. ■

— John Norris

Northeast news from our other channels



JFK Airport Adding Solar/Fuel Cell Microgrid

NetZero Insider

Multiple Projects Offered in 3rd NY OSW Solicitation

NetZero Insider

Firm Plans Long-Duration Zinc-Air Battery Factory in NY

NetZero Insider

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

NYISO News

FERC Conditionally Accepts NYPA Formula Rate Revisions

By John Norris

FERC on Jan. 23 conditionally accepted the New York Power Authority's (NYPA) proposal to revise its formula rate template in response to its need to bring on large amounts of clean generation.

In its filing with FERC, NYPA sought to "update the allocation methodology for administrative and general costs and expenses as well as depreciation and net plant costs for general plant (A&G), incorporate a transmission rate incentive and a cost containment mechanism for the Smart Path Connect Project, and make certain technical and clarifying improvements to the formula rate template," the commission noted in the order (*ER23-491*).

A political subdivision of the state of New York, NYPA is classified as both a "municipality" and "state instrumentality" under the Federal Power Act. The agency has no specific service territory, but it generates, transmits and sells electricity at the wholesale and retail levels throughout New York. Since the creation of NYISO, NYPA has recovered the cost of its transmission facilities through the NYPA Transmission Access Charge (NTAC), which is assessed to most loads in NYISO on a load-ratio share basis.

In seeking the revisions, NYPA asserted that, because of New York's aggressive climate change initiatives, the organization's "business focus and investment profile has shifted such that transmission development and construction are the dominant activities," meaning that the current "single factor ratio allocator is no longer the appropriate allocation."

NYPA proposed using a "multi factor modified Massachusetts Method of allocation," arguing that the method "uses an equally weighted average of direct labor, net plant, and net revenue ratios" and "has broad regulatory acceptance and aligns with utility practice."

The Municipal Electric Utilities Association of New York (MEUA) disagreed, contending that NYPA "failed to demonstrate how the adoption of a multi factor allocation of A&G costs is just and reasonable." MEUA argued that using the Massachusetts Method "will likely assign a larger portion of A&G costs to the transmission function recovered in NTAC rates and less to its other profit centers."

NYPA responded that the changes are simple "nomenclature changes" that would not "have material impacts" nor impose "A&G costs on NYPA's transmission customers," providing the commission no reason to rule against the proposals.

However, FERC said its preliminary analysis indicated that NYPA's revisions might not meet its standard for justness and reasonableness and set the issue to a settlement judge hearing.

"We note that the proposed Formula Rate Template revisions to implement the proposed change in the A&G allocator go beyond NYPA's assertion that the revisions are only changes in nomenclature or a non-ratemaking change," the commission wrote. "Further, the incorporation of an allocation methodology is not an 'accounting change,' as NYPA asserts. Specifically, the proposed changes to the Formula Rate Template provide for a changed allocation of A&G costs to ratepayers and provide for changes to the Formula Rate Template that allow for the use of new inputs for those costs."

The commission also pointed out that the Massachusetts Method is typically used by holding companies to allocate A&G costs between the non-revenue generating holding company and its subsidiaries.

"NYPA, however, is a corporate municipal instrumentality and a political subdivision of the State of New York. NYPA's proposal includes no support for its claim that the Massachusetts Method is appropriate for its specific circumstances and structure," the commission said.

FERC accepted NYPA's filing for the proposed rate revisions, making them effective Jan. 23 but subject to refund pending the outcome of the hearing. The commission encouraged parties to the proceeding to reach a settlement before hearing procedures commence within 45 days of the order. ■

FERC headquarters in D.C. | *© RTO Insider LLC*

NYISO News

NYSERDA: 3rd OSW Solicitation Breaks Record

Developers Submit Dozens of Proposals for NY Projects

By John Cropley

New York said Friday that its latest offshore wind solicitation drew a record level of response for an East Coast state: more than 100 proposals from six developers for eight new projects.

The New York State Energy Research and Development Authority, which is shepherding the state's offshore wind buildout, said it would post summaries of the proposals after reviewing them. After the solicitation closed at 3 p.m. Thursday, five of the developers publicly announced their intentions.

"The high volume of quality proposals from leading global energy developers is a testament to the state's ability to attract strong competition and significant investments in New York's clean energy economy, ports and the development of long-term domestic supply chain," NYSERDA said in an email. "Following a rigorous evaluation period, NYSERDA expects to announce the awards in spring 2023."

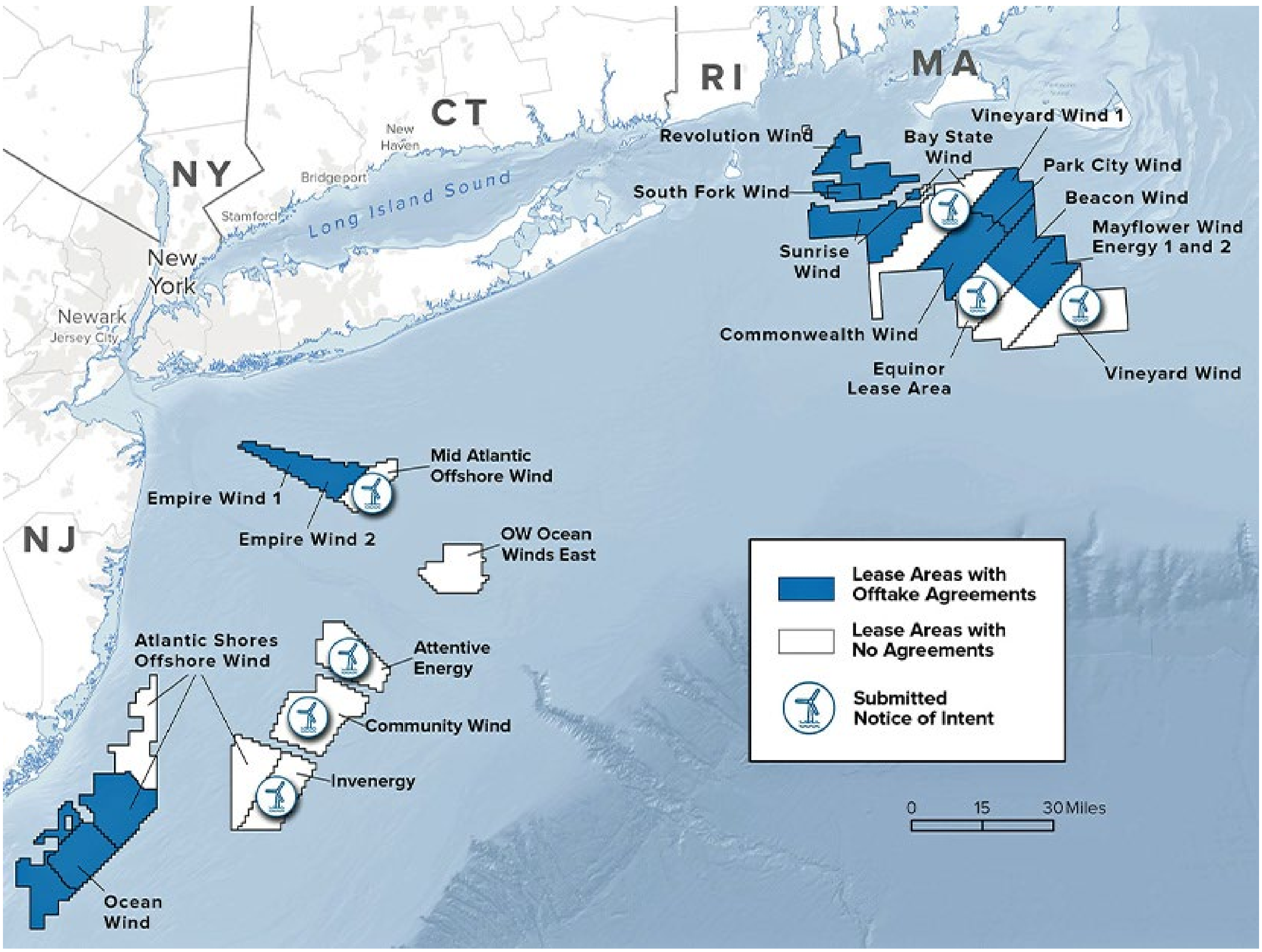
Among the state's priorities in this third solicitation was development of an in-state supply chain. One of the oldest names in the power industry, General Electric, will potentially help make that happen.

GE *said* Thursday that if there were enough orders for projects in New York waters, it would build two factories in Coeymans, 130 miles up the Hudson River from New York Harbor: one for nacelles, and one for blades for the next generation of GE's Haliade-X offshore turbine.

Ørsted and Eversource Energy already *have contracted* with Riggs Distler to build foundation components at the Port of Coeymans for their Sunrise Wind project.

At the nearby Port of Albany, a manufacturing plant for turbine towers is planned by a partnership that includes Equinor.

The move would be a reversal of sorts for



This map shows wind energy projects proposed off the coasts of New York, New Jersey and New England as of the end of 2022. | *NYSERDA*

NYISO News

GE, which was born in 1892 in Schenectady, not far from Coeymans. The conglomerate, which is now dissolving, long ago moved its headquarters out of Schenectady and has been shrinking its footprint there and elsewhere in upstate New York for decades through cutbacks, closures, spinoffs and business sales.

"As a leading manufacturer and innovator in developing renewable energy technology, GE is ideally positioned to help New York secure its vision of becoming a leading manufacturing hub for offshore wind technology," Scott Strazik, CEO of the new GE Vernova, the company's portfolio of energy businesses, said in a statement. "Our proposal leverages GE's unique and unparalleled expertise, resources and track record — including a 130-year legacy of manufacturing in New York — to make this vision a reality in a durable and sustainable way."

Notices of intent to submit proposals in this third solicitation were due Dec. 1. NYSERDA said it received notices from Attentive Energy, Bay State Wind, Beacon Wind, Community Offshore Wind, Invenergy Wind Offshore and Vineyard Offshore Wind.

Publicly announcing their intentions Thursday and Friday were:

- Vineyard Offshore, which proposed two projects — Excelsior and Liberty Wind — with a combined capacity of 2.6 GW. They would entail the largest investment to date in the U.S. supply chain infrastructure for the young offshore wind industry and provide more than $15 billion in direct economic benefits, Vineyard said. The proposal is backed by Copenhagen Infrastructure Partners, with is building Vineyard Wind I off Massachusetts in a 50/50 venture with Avangrid.
- Community Offshore Wind, a joint venture of RWE and National Grid Ventures, which said it would create more than 4,600 jobs, deliver more than $3 billion in economic benefits and collaborate with GE on the factories as it developed a 1.3-GW wind farm.
- Leading Light Wind, a partnership between Invenergy and energyRE, which proposed a wind farm generating up to 2.1 GW of power and offering up to $13.3 billion in economic benefits to the state. Leading Light noted that it is the only American-led wind developer in the New York Bight, and that the two partner firms are developing the $11 billion Clean Path NY transmission project with the New York Power Authority.
- Equinor and BP, already partners on Beacon Wind 1 and Empire Wind 1 and 2 off the New York coast, which submitted a proposal for a 1,360-MW installation in the Beacon Wind 2 lease area. In a news release Thursday, Equinor and BP said their plan would complement the 3.3-GW combined output of the three other wind farms and generate more than $11 billion in new economic activity statewide.
- Ørsted and Eversource, already partners on South Fork Wind and Sunrise Wind off the New York coast, which submitted multiple bids with different configurations. The common factor, according to the companies, would be billions of dollars in economic activity, strides for economic justice, prioritization of disadvantaged communities and minority- and women-owned businesses, and furtherance of the state's climate goals. Ørsted and Eversource are also partners in Bay State Wind. ■

NYISO News

NYISO Presses Onward with DER Revisions; Stakeholders Struggle to Keep up

ISO Kicks off Project to Improve Capacity Accreditation

By John Norris

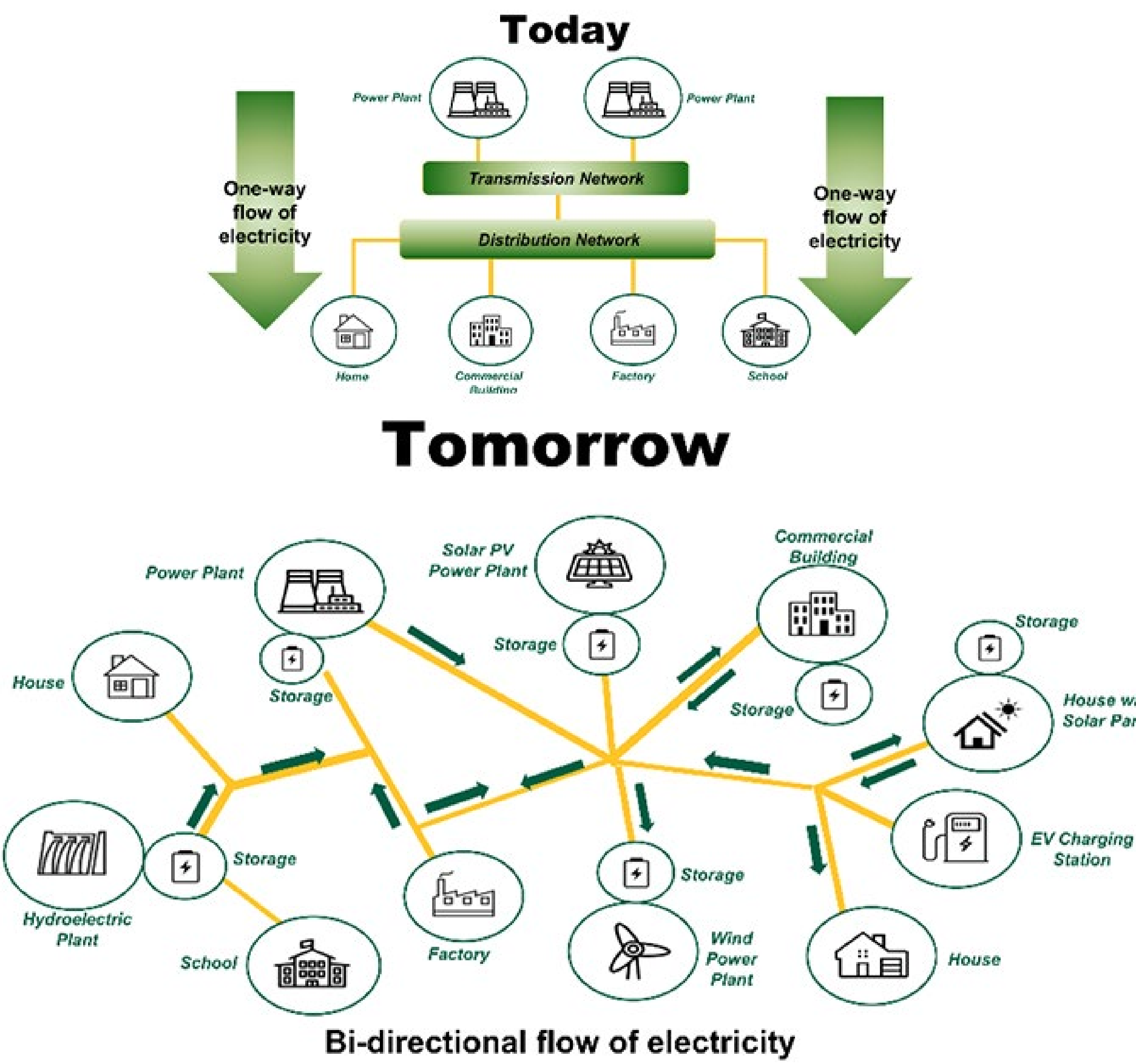
NYISO on Thursday *presented* the Installed Capacity and Market Issues Working Groups (ICAP/MIWG) with further revisions to its proposed rules for distributed energy resource aggregations based on stakeholder feedback, but the groups' members continued to express concern and confusion.

As it is never clear exactly which resources in an aggregation are providing electricity, NYISO has proposed to calculate their reference levels based on lists of average marginal costs for different resource types. "Aggregation-level offers will include a resource type from this list for each hour to indicate the highest-cost resource that is available to produce energy in the aggregation," according to the ISO. "The NYISO-estimated marginal cost of that resource type will serve as the reference level for the entire aggregation for that hour."

But there was extensive discussion and questions at the meeting about how exactly NYISO would do this, and how this would influence market bids and signals.

Aaron Breidenbaugh, director of regulatory affairs at CPower Energy Management, questioned NYISO's proposed cost-based approach and why it didn't stick with locational-based marginal prices. He said market participants who possess variable operations, such as crypto miners, may struggle to produce granular reference points to decide whether to make offers and may see "their net revenues being held hostage."

NYISO responded that LBMPs and bid-based



DER Future Impact on Grid | *NYISO*

NYISO News

reference levels are based on 90-day historical data, but an aggregation's composition can change day to day. A cost-based approach would enable aggregators to dynamically reflect different technology types, though the ISO expects that when someone "makes an offer based on their estimated marginal cost of production, they should be able to reflect that."

Stakeholders also continued to express confusion over how aggregations would be deployed and the timing for the transition to the new construct. (See *NYISO Stakeholders Still Concerned About DER Participation Model*.)

Julia Popova, NRG Energy's manager of regulatory affairs, said she was concerned that dispatched generators would not be compensated in the real-time market, even though they made bids based on ISO economic forecasting in the day-ahead market showing their units being profitable.

"In real time, there is opportunity to buy out our position, but with everything else going on with DERs, it does not work every time as intended," Popova said.

"If NYISO can't give us to the tools to make sure we aren't dispatched uneconomically, then it is not fair to penalize us" because "we did what we said we would do based on [the] day-ahead," Breidenbaugh chimed in.

NYISO offered stakeholders offline discussions in response to concerns and told them about upcoming training opportunities to help with onboarding. It expects to begin accepting customer registrations for DER aggregations in mid-April and anticipates the proposed tariff revisions becoming effective in early summer.

The ISO will seek approval of revisions from the Business Issues and Management Committees on Feb. 15 and Feb. 22, respectively, and will return to the ICAP/MIWG to continue discussions on necessary manual revisions.

	2023-2024 Capability Year					2022-2023 Capability Year				
Four-Control-Area-Participation	PJM	ISO-NE	Quebec	Ontario	Totals	PJM	ISO-NE	Quebec	Ontario	Totals
Initial Values (TTC Summer Ratings)	1450	1400	1690	1950	6490	1450	1400	1690	1850	6390
Grandfathered Rights*	1080	0	1110	0	2190	1080	0	1110	0	2190
Individual Limits (above GF)	193	250	39	268	750	218	401	17	77	713
Individual Limits (above GF) Delta	-25	-151	-22	191	-129					
Simultaneous Limits (above GF)	58	75	11	80	224	66	122	5	23	216
Simultaneous Limits (above GF)Delta	-8	-47	6	57	8					
Final Values **	1138	75	1121	80	2414	1146	122	1115	23	2406
*Final Values** Delta*	-8	-47	6	57	8					

2023 Import Rights for Neighboring Control Areas | *NYISO*

Capacity Accreditation Kickoff

NYISO *kicked off* its capacity accreditation modeling improvements project, one of many that the ISO wants to prioritize this year. (See *NYISO Outlines Timelines for 2023 Projects*.)

Zach Smith, NYISO capacity market design manager, said the effort "allows a twofold change": more accurate representation of installed reserve margins (IRMs) and locational capacity requirements (LCRs) in resource adequacy models, and more accurate capacity accreditation factors for capacity accreditation resource classes.

NYISO scoped out four topics that need to be addressed:

- gas constraints for fuel availability;
- long start-up notification requirements;
- modeling of special-case resources (SCRs); and
- dealing with non-fuel-related correlated derates, as identified by the Market Monitoring Unit. (See *NYISO Over-crediting Poorly Performing Units' Capacity, Monitor Says*.)

NYISO does not currently capture natural gas constraints, nor start-up notifications for non-baseload units, in the IRM/LCR models. SCRs, although currently modeled, were found to not align with their expected performance and obligations.

But Smith said the ISO expects to spend most of its efforts this year on tackling the problems identified by the MMU by better capturing how ambient conditions impact correlated derates of combined cycle and combustion turbines.

NYISO will spend the first and second quarters analyzing areas for enhancement; the third quarter identifying any solutions; and the rest of the year either prototyping these solutions or making implementation recommendations. It plans to return to the ICAP/MIWG next month to discuss gas constraints, SCR modeling and the correlated derate issues. ■

PJM News

Dominion-backed Bill Promises Savings, but Comes with Strings

Critics Argue it would Hamstring the State Corporation Commission

By James Downing

Dominion Energy is backing legislation in Virginia that critics say would limit the State Corporation Commission's ability to set its rates, while the utility has claimed it would save consumers millions.

Senate Bill 1265 also initially included language that would have made energy shopping by large commercial and industrial customers "nearly impossible," according to the Retail Energy Supply Association, but that was removed as it advanced through a Senate subcommittee earlier this month.

"As Virginians face historic inflation and rising energy costs, there is broad agreement that consumers need relief on their power bills," a Dominion spokesperson said. "The proposed legislation would provide immediate and ongoing rate relief to our customers. It would provide strong state regulatory oversight. And it supports our mission of delivering reliable, safe, affordable and clean energy to our customers."

The bill, sponsored by Sen. Richard L. Saslaw (D), cleared the Energy Subcommittee by a 4-1 vote, and it still must clear the full Commerce and Labor Committee before it can be voted on by the Senate. A House version of the legislation, *HB 1770*, has not moved forward yet.

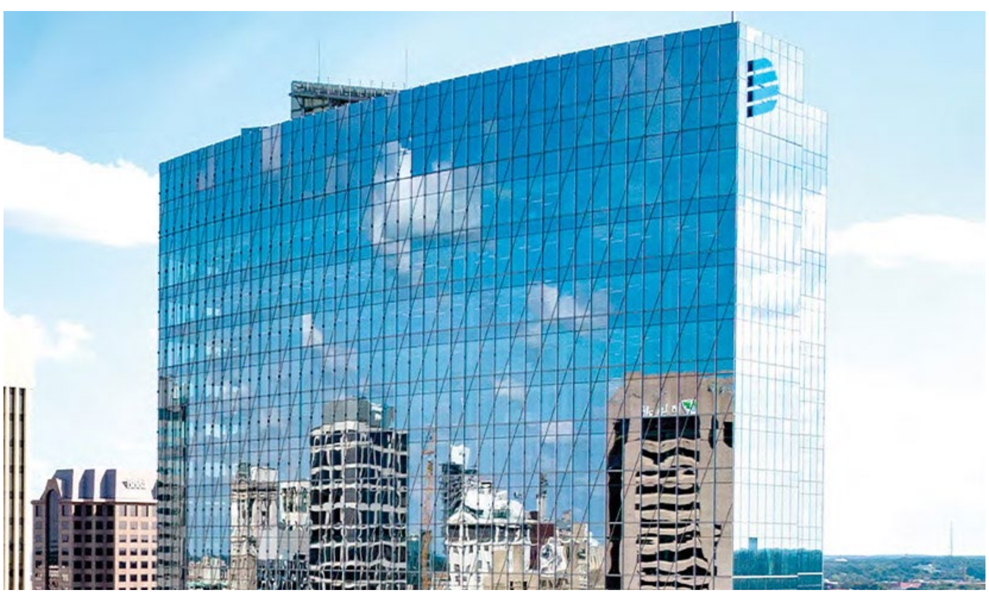
Ever since Virginia decided against moving forward with retail restructuring back in 2007, state law has required the SCC to set Dominion's rates based on a group of its investor-owned peers in the Southeast.

The bill would eliminate the SCC's ability to remove the two highest returns on equity and two lowest returns from that peer group when setting Dominion's rates. In return for that, it would shift some costs from riders to the firm's base rates and make it go through rate cases every two years instead of every three.

Eliminating those riders would save $300 million annually effective July 1, which would save the average customer bill about $5 to $7 per month.

While the bill removed any language dealing with electric shoppers, at a Senate Energy Subcommittee hearing Jan. 18, lawmakers indicated that they want to hear from the SCC on whether shopping shifts costs to remaining customers. That is an issue in California's capped power market, where cost shifts from customers leaving utility service are covered through a mechanism called the power charge indifference adjustment.

"Our rates have been below the national average for some time," Dominion Senior Vice President of Corporate Affairs Bill Murray said at the hearing. "This is a way for us to keep our rates below the national average, while having the certainty we need to raise a great deal of capital to build needed infrastructure, whether its generation, transmission or grid-hardening."



Dominion Energy headquarters in Richmond, Va. | *Dominion Energy*

The current peer group on which Dominion's rates are based is made up of about 10 utilities in the Southeast, and Dominion has the lowest rate of return on equity among them, Murray said. That peer group has shrunk from about 20 when the legislature first set it up 15 years ago because of industry consolidation, so removing two highest returns and two lowest has a much bigger impact on Dominion's rates than it used to.

If Dominion wanted to offer customers $300 million in savings, the firm could do so on its own without any legislation, Southern Environmental Law Center's Will Cleveland said at the hearing.

"This legislation does not let the Virginia commission set the rate of return for the Virginia monopoly utilities — that is our concern," Cleveland said.

Walmart lobbyist Kenneth Hutcheson told the subcommittee the retailer appreciated the removal of changes to the state's shopping rules, but he said the peer group should be expanded to include vertically integrated utilities from the Midwest and Gulf Coast.

Attorney Will Reisinger testified at the hearing on behalf of Clean Virginia, saying it would remove the ability of the SCC to independently set Dominion's rates.

Eventually all the investments Dominion is making, including projects to meet the goals of the Virginia Clean Economy Act such as the 2.6-GW Coastal Virginia Offshore Wind project, would be impacted by any higher rates of return Dominion is able to get under the legislation, Reisinger said in an interview.

"It's pretty extraordinary for a monopoly utility to try to set its own rate of return via legislation," Reisinger told *RTO Insider*. "This is exactly what public utility commissions were designed to do — set the utility's ROE at the correct level."

The Dominion-backed legislation isn't the only bill under consideration.

Senate Bill 1321, sponsored by Sen. Jennifer McClellan (D) and Sen. Creigh Deeds (D), and *House Bill 1604*, sponsored by Del. R. Lee Ware (R), would allow the SCC to lower a utility's base rates if it finds they result in "unreasonable revenues in excess of the utility's authorized rate of return." The bill has also been assigned to the Senate subcommittee. ■

PJM Stakeholders Endorse Accreditation Changes for Renewables

By Devin Leith-Yessian

VALLEY FORGE, Pa. — PJM's Markets and Reliability Committee and Members Committee on Wednesday endorsed a *proposal* to change the RTO's accreditation methodology for intermittent resources.

The proposal would revise PJM's effective load-carrying capability (ELCC) methodology — used to determine the amount of capacity a resource can offer — to limit the hourly output entered in the modeling at the facility's capacity interconnection rights (CIR) rating.

Currently CIRs are not considered in the ELCC process, but they are used downstream to cap accreditation. The result is that the ELCC value of intermittent resources is overstated and the CIRs that the resources had to purchase to support the ELCC value is understated, Independent Market Monitor Joe Bowring argued. PJM's current practice of including hourly output above a resource's CIR rating in its ELCC analysis when setting accreditation has been the source of much of the contention over the two years and is the subject of an ongoing complaint to FERC (EL23-13). (See *Stakeholders Challenge PJM in Capacity Accreditation Talks*.)

The changes were passed with more than 90% support at the MRC and 89% support at the MC. The PJM Board of Managers is set to consider them this Wednesday; if approved, PJM will file them with FERC the next day.

The provisions also include a transitional mechanism in which existing generators — including those still in development, but already holding interconnection service agreements (ISAs) — can apply for a portion of the available transmission headroom on the grid.

The proposal, submitted by PJM as "Package I," was approved by the Planning Committee on Jan. 10. Other proposals considered, but ultimately rejected, by the PC would have immediately granted existing resources the CIRs they would be granted under the new system, while others would have required those generators to apply for new capacity ratings and re-enter the queue. (See *PJM Planning Committee Endorses Capacity Accreditation for Renewables*.)

Generators seeking transitional capacity must file a CIR uprate request during a 30-day window, which is currently set to open on Thursday. The transitional studies determining the amount of headroom that can be granted to resources would begin on March 3, to be completed by April 21.

LS Power Amendment Fails

An *amendment* to the proposal put forward by LS Power would have required that any resources granted access to transmission headroom through the transitional studies either utilize that allocation or relinquish it.

The company's Tom Hoatson said the change is a logical outgrowth of stakeholders' desire in forming the proposal to limit discrimination between resources and would prevent hoarding or the exercise of market power.

PJM CEO Manu Asthana noted the interaction between CIRs and ELCC has long been a divisive issue for stakeholders and said that he believes that rather than introducing an amendment as endorsement is being considered, it would be better to vote on the larger proposal and continue deliberations on headroom utilization separately.

"This is a topic that we've worked on for a long time. It's been very contentious and hard fought to get to consensus," he said.

Though he could understand the perspective of those who believe that the amendment was an extension of the proposal's existing non-discrimination provisions, Asthana said he disagreed that the amendment fit into the intent of the package. He also worried that the language would function as a must-offer requirement.

Bowring said that it would be inefficient to have headroom allocated to generators that do not commit to using it and that it would not function as a *de facto* must-offer requirement — a provision he's long pushed for. He stated that "the temporary headroom is a valuable product that is being assigned to some resources at zero cost. The failure to require that the recipients of the temporary headroom actually use it means that they are preventing other resources from using the headroom. Without attributing intent, this is a form of withholding that is not consistent with an efficient, competitive market outcome.

"I don't think it's an expansion of the must-offer. As much as I would like it to be that, it's not that," he said.

PJM staff said that the original text of the amendment would be difficult to implement and inaccurately referenced CIRs rather than transitional headroom. At Asthana's recommendation, staff worked with Hoatson outside the room while the committee moved onto other agenda items, returning with a *reworked amendment*.

In objecting to the language's presentation as an amendment, Manuel Esquivel of Enel North America said it appeared to be an overly constrained provision within a larger proposal, with a lot of moving parts and open questions. Even when a generator's intent is to absolutely use the additional requested capacity, the dynamic nature of the transitional process may result in a particular generator ultimately not being able to use the headroom they sought.

He worried that the text would effectively function as a requirement that participating intermittent resources must offer into Base Residual Auctions (BRAs). Instead of creating such a requirement through an amendment, he said that should be part of the discussions at the Resource Adequacy Senior Task Force, which is currently engaged in considering changes to the capacity market.

"We're not comfortable with establishing something akin to a must-offer requirement for all resources in a vacuum," he said.

Because there was an objection to the text's adoption as an amendment, it was instead presented as an alternative motion. And because stakeholders ultimately endorsed the main motion, they did not vote on the amendment. ■

PJM CEO Manu Asthana (middle) speaks during the Jan. 25 meeting of the Members Committee. | © *RTO Insider LLC*

PJM News

PJM MRC/MC Briefs

Markets and Reliability Committee

MRC Discusses MSOC and CPQR Changes

The *PJM* Markets and Reliability Committee added a discussion of the market seller offer cap (MSOC) and capacity performance quantifiable risk (CPQR) to its Jan. 25 agenda at the behest of stakeholders concerned that the current constructs may not fully reflect the risk of penalties paid during emergency conditions.

Jeff Whitehead, of GT Power Group, said the current MSOC was built on the assumption that emergency performance assessment intervals (PAIs) would be few and far between. However, the 277 PAIs occurring on Dec. 23 and 24 during Winter Storm Elliott has challenged that notion.

With the 2025/26 Base Residual Auction (BRA) approaching and generation owners facing as much as $2 billion in performance penalties stemming from Elliott, Whitehead said it's important that sellers are able to understand how the storm will impact the offers they can submit. (See *PJM Gas Generator Failures Eyed in Elliott Storm Review*.)

PJM Vice President of Market Services Stu Bresler said there are two meetings of the *Resource Adequacy Senior Task Force* (RASTF) — including Jan. 31 — and one *Market Implementation Committee* meeting before the next MRC meeting. He said the issue can be added to those agendas with the goal of having a proposal to present to the MRC at its February meeting. Given the current timeline for the June BRA, he said actionable market changes would likely require an alternative auction schedule.

Jeff Whitehead, GT Power Group | © *RTO Insider LLC*

Jason Barker, Constellation Energy | © *RTO Insider LLC*

Gregory Carmean, of the Organization of PJM States Inc. (OPSI), said that any changes to the auction schedule would be disruptive to states that run their own markets to procure energy.

Noting that the funding for bonus payments is derived from the penalties paid by underperforming generators, Carmean questioned why the capacity performance mechanism results in "exorbitant prices" for ratepayers and doesn't net out to be cost neutral. Given that energy-only resources aren't subject to penalties, he also asked why they are eligible to receive bonus payments.

PJM's Adam Keech said the bonus payments are distributed to any overperforming resources to create an incentive to provide power when it is needed most, regardless of whether it comes from capacity or energy resources.

Jason Barker, of Constellation Energy, said many small or new market participants may not have developed the tools needed to fully model the performance risk to their facilities, creating a roadblock to offering as a capacity resource. A pro forma system where sellers can provide data and receive expectations of how their unit may perform could be a short-term step as broader market designs are considered.

Independent Market Monitor Joseph Bowring said it's reasonable to raise the narrow issue of the interaction between Elliott and PJM's market mechanisms.

"It is straightforward to include the PAI data from Elliott in the simulation calculations used to calculate CPQR," he said. "But is important not to be hyperbolic about the impact of the Elliott PAI. It should come as no surprise to anyone that the market experienced PAI. But this is the first significant PAI event in the history of CP. This can be handled within the existing rules."

Greg Poulos, of the Consumer Advocates of the PJM States (CAPS), noted that the conversation was occurring little more than a month out from the storm and data collection is still underway. Rather than rushing the MSOC conversation, he pushed for a more cautious approach.

"Overall, we would prefer to have a comprehensive market discussion and go at it that way rather than have a piecemeal and plug a hole, with a couple bandages over it," he said.

Stakeholders Endorse Expansion of Hybrid Resource Rules

The rollout for the *second phase of market rules* for hybrid resources was approved by the MRC Wednesday, expanding the definition of

PJM News

hybrid to any combination of fuel types. The first phase created a set of market rules for the most predominant form of mixed-fuel facilities, solar and storage combinations, with the classification and metering language effective Oct. 1, 2022, and the energy market model scheduled to go live this June. The proposal requires FERC approval. (See *PJM MRC Moves Forward on Storage, Hybrids*.)

The new hybrid definition would allow for more resource pairings, such as hydrogen and solar or gas and solar, to benefit from the market provisions in the first phase, regardless of whether they are paired with storage. The market model for inverter-based storage hybrids is based on the phase one structure.

The proposal approved last week creates a new market model for inverter-based, generation-only hybrids, such as wind and solar modeled on the existing system for wind resources. The EcoMax and uplift parameters currently in place for wind resources are also being applied for hybrids.

Other MRC Business:

- Stakeholders endorsed *revisions* to the charter for the emerging technologies forum to shift toward an emphasis on stakeholder discussion and debate, rather than a focus on education. The changes also include references to new Manual 34 language regarding forums, including added clarification that discussions in forums cannot be used to bypass the existing stakeholder issue resolution process.
- The MRC approved a *proposal* to change how PJM models power flows in its day-ahead model to look at all 24 hours for the reference date. With changes in load patterns, particularly from behind-the-meter solar and data center development, PJM's Amanda Martin said additional accuracy in aligning day-ahead and real-time flows is necessary. (See "First Read on Changes to Day-ahead Zonal Load Bus Distribution Factors," *PJM MIC Briefs: Nov. 2, 2022*.)

Adrien Ford, Old Dominion Electric Cooperative | *© RTO Insider LLC*

Members Committee

Stakeholders Endorse Pathway for Issues to be Brought Directly to MC

The Members Committee endorsed a *motion* from Adrien Ford, of Old Dominion Electric Cooperative, to allow members to bring some issues best addressed by the MC directly before the body through a problem statement and issue charge, rather than having to be first considered by lower committees. The manual revisions were endorsed by the committee by acclamation with eight objections and five abstentions, all in the end-use customer sector.

Poulos said it's best to have a problem statement and issue charge whenever possible to allow stakeholders to have a clear understanding of why a topic is being discussed. However, he worried that requiring those could lead to administrative discussion down the road that gets in the way of substantive work.

He asked Ford if she would be amicable to an amendment to her language to change the requirement that a problem statement and issue charge be approved by the MC be changed to recommend, but not mandate, that process. Such a change would also allow for issues to be voted on by the committee the same day they're broached.

Ford said she could not accept the amendment, as the language was drafted by a group of stakeholders over a long period of time.

PJM Considering New Non-performance Charge Billing Schedule

PJM CFO Lisa Drauschak *presented* a series of adjustments the RTO is considering to its non-performance charge billing schedule to extend the amount of time market participants have to make payments when performance assessment intervals (PAIs) fall near the end of the delivery year.

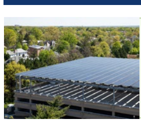
Currently, billing is split between the remaining months in the delivery year after the charges have been determined for a generator. For PAIs in the summer this leaves as much as nine months for payments to be made, but for Winter Storm Elliot there will only be three months to make payments once the penalties have been determined.

PJM's proposal would amend the tariff to allow payments to be split over an additional six months if less than six months remain in the delivery year once charges have been determined.

A second option being considered is to allow members who have been assessed penalties to elect to either pay them across the greater of the remainder of the delivery year, or three months, with no interest, or to have a six-month floor with interest added at the FERC prevailing rate. The alternative is based on stakeholder feedback received during the Jan. 24 meeting of the Risk Management Committee regarding the possibility of incorporating interest into the payment methods.

PJM General Counsel Chris O'Hara said that under the current language, if there were to be a PAI in the last two months of a delivery year, the collection period would already extend into the next delivery year, so the proposal is also an attempt to fix a broken provision. ■

Mid-Atlantic news from our other channels



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SPP News

FERC Rejects GridLiance, AECI Rehearing Requests

Commission Unmoved by Argument over Facilities' Classification

By Tom Kleckner

FERC on Jan. 19 dismissed as moot GridLiance High Plains' request to rehear last year's ruling that the utility failed to prove that certain Oklahoma facilities were eligible for cost recovery as transmission infrastructure and not distribution-related infrastructure (*ER18-2358*).

The commission said it was not persuaded by GridLiance's assertions that FERC inappropriately shifted to the utility the burden of proof to demonstrate that its facilities are transmission facilities under *Order 888*'s seven-factor test.

GridLiance filed its request in October after FERC affirmed in part and reversed in part an administrative law judge's previous decision in hearing and settlement procedures addressing SPP's proposal to revise its tariff to incorporate an annual transmission revenue requirement. The change would have placed the Oklahoma Panhandle facilities into Southwest Public Service Co.'s transmission pricing zone. (See "Commission Rejects SPP Tariff Revision, Reversing ALJ Decision," *FERC Revokes Tri-State's Market-based Rate Authority in WACM*.)

FERC has rejected a GridLiance rehearing request over the classification of distribution facilities in Oklahoma's Panhandle. | *GridLiance*

GridLiance argued that FERC erred by putting the burden of proof on the utility. It said it satisfied that burden when it showed "by a preponderance of evidence" that the facilities are transmission facilities under SPP's tariff and were appropriately classified. The commission's interpretation "silently subsum[es]" the seven-factor test and contradicts SPP's filed tariff by adding certain conditions, GridLiance said.

But the commission said it was not persuaded, noting it had already rejected the same argument last year and finding that GridLiance did not provide a "persuasive reason" to revisit its decision. It continued to find that under the Federal Power Act's burden-of-proof framework and FERC precedent that requiring Xcel Energy, SPS' parent company, to carry the seven-factor burden of proof would "effectively shift the onus" from SPP and GridLiance.

"SPP and GridLiance … bore the ultimate burden of persuasion with respect to the filing," FERC said. "Classification of the GridLiance facilities as transmission facilities was an integral component of that filing, and the commission has established that the seven-factor test may be applied for the purpose of that classification."

FERC did grant GridLiance's request for clarification, saying the facilities may continue to be classified as distribution facilities. It said the proceeding did not demonstrate that upgrades to the facilities changed their classification.

Commission Sustains Order in AECI Proceeding

The commission also rejected a rehearing request from Associated Electric Cooperative Inc. (AECI), sustaining a 2022 order that found the commission was appropriate in exercising primary jurisdiction over SPP's sales of emergency energy during February 2021's winter storm (*EL22-54*).

FERC again found that SPP properly compensated AECI and that the transactions were made under a commission-jurisdictional tariff. (See *FERC Rules for SPP in AECI Dispute*.)

The co-op appealed the decision in September, arguing that FERC ignored evidence of oral agreements between the parties that led to AECI responding to the SPP's verbal requests for emergency power during the storm. It said the commission relied on "post hoc rationalizations" in labeling the emergency transactions as market transactions.

FERC disagreed, saying the SPP tariff, the AECI-SPP joint operating agreement and AECI's market participant agreement constituted the "filed rate applicable" to energy transactions, making the co-op's status as a neighboring BA "irrelevant" in determining whether it is bound by those agreements.

"Assum[ing] a rate would be charged other than the rate adopted by" the commission would violate the filed rate doctrine, the commissioners wrote.

The commission dismissed AECI's argument that FERC erred in granting SPP's petition that FERC issue a declaratory order to declare that the grid operator had paid AECI the "full, correct and only legally permissible rate" for the emergency power.

FERC reiterated that it is appropriate for the commission to exercise primary jurisdiction over the transactions as it followed precedent and has the appropriate "expertise" to make such decisions.

"The commission has special expertise interpreting jurisdictional wholesale rates like SPP's tariff, the AECI-SPP JOA and the AECI MP Agreement because [it] oversees the rules governing wholesale markets like SPP's Integrated Marketplace … and is therefore best positioned to understand the meaning of the terms and conditions in the filed rate," FERC said. ■

SPP News

SPP MOPC Approves Late Resource Adequacy Revisions

SPC Delays Implementation of CRSP Terms for RTO West

By Tom Kleckner

SPP's Markets and Operations Policy Committee on Friday approved two revision requests related to resource adequacy requirements that members had set aside during their regular quarterly meeting earlier this month.

The special conference call became necessary when MOPC deferred action on the RRs after several late changes were shared with members the night before the January meeting began. The committee directed SPP staff and the Market Monitoring Unit to re-engage with stakeholder groups to ensure members still agreed with the changes. (See "Members Defer on PRM Deficiency RRs," *SPP MOPC Briefs: Jan. 17-18, 2023*.)

"We've kind of taken them on a roadshow," the MMU's John Luallen told MOPC during the call.

Taken together, *RR536* and *RR537* would provide load-responsible entities with a short-term, non-punitive alternative approach to deficiency payments for the summer resource adequacy requirement (RAR). Staff have been working on the mitigation strategy since July, when SPP increased the planning reserve margin (PRM) from 12% to 15%, effective this year. That left some members complaining they would not have enough time to meet the requirements. (See *SPP Board of Directors Briefs: Dec. 6, 2022*.)

The Supply Adequacy, Cost Allocation and Regional Tariff groups all approved the RRs last week by a combined vote of 75-1, with 28 abstentions, making only various non-substantive terminology edits.

MOPC then endorsed the tariff revisions in separate electronic ballots. Solar and storage developer Savion cast the only dissenting vote. The measures will now go before SPP's Board of Directors and Regional State Committee this week for final approval. Staff hope to gain FERC's approval in time to accredit resources for the summer season (June 1-Aug. 31).

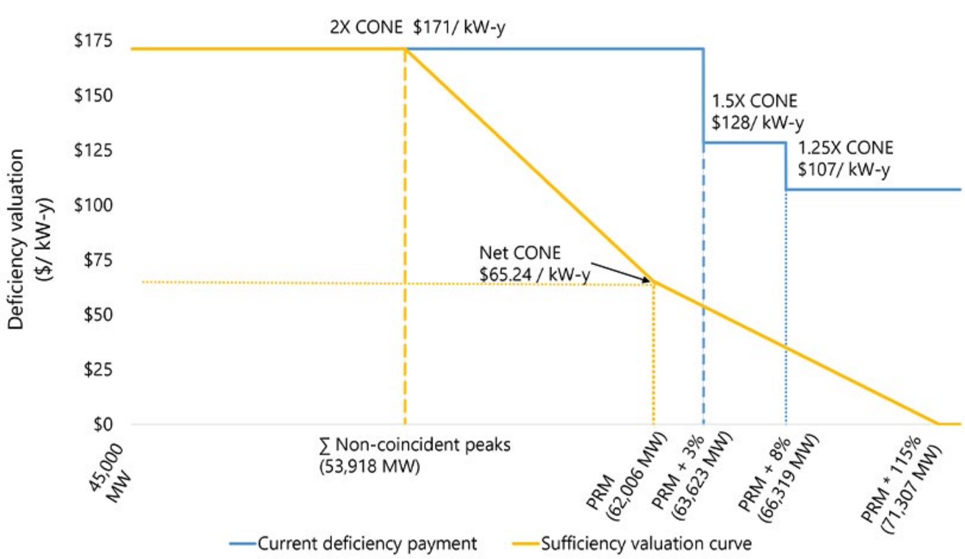
Stakeholders modified RR536 to clarify that LREs can make a sufficiency payment only when the PRM is increased within the previous two years and the LRE demonstrates it had adequate capacity to meet the PRM before it was changed. A deficiency cannot result from selling accredited capacity to another region after the PRM's increase is approved.

Under the change, capacity can only be claimed for accreditation by one asset owner in the SPP footprint. Capacity used to resolve deficiencies cannot be sold to another region for the applicable resource adequacy requirement season.

The measure includes the MMU's proposed sufficiency valuation curve to value capacity in the market. The curve starts at twice the cost of new entry (CONE) at or below the sum of noncoincident peak loads, then slopes downward to a net CONE value when regional accreditation reaches the PRM. When the region has sufficient accredited capacity, the net CONE drops down to zero at 115% of the PRM.

RR537 emerged from the last-minute stakeholder process with revised language that removes a tariff violation when LREs fail to make a resource adequacy payment. As modified, LREs would be deemed sufficient for the adequacy requirement with a deficiency payment.

The change was also modified to clarify that only capacity resolving deficiency is obligated to stay in SPP; the obligation only applies to a specific RAR season; and that a deficiency payment is based on a kilowatt-year.



SPP Market Monitoring Unit's proposed valuation curve for resource adequacy requirements | *SPP*

CRSP Faces Tx Rate Issues

The grid operator is working to address concerns by one of nine entities evaluating membership in its RTO West offering over its restrictions as a federal power marketer.

The Western Area Power Administration's Colorado River Storage Project (CRSP) in November requested changes to the terms and conditions for RTO membership, approved last July. Those terms were to be effective March 1, but SPP's Strategic Planning Committee endorsed a four-month extension to July 1 and additional terms and conditions during its Jan. 18-19 meeting.

The new terms include crediting CRSP's point-to-point (PTP) transmission service and a federal service exemption (FSE) of replacement energy to satisfy its statutory load obligations.

The board will consider staff's recommendation during its quarterly meeting today. The changes are contingent upon WAPA publishing its intent to join the RTO West in the *Federal Register* by Feb. 28.

Asked what SPP would do should other obsta-

SPP News

cles pop up before July, Bruce Rew, senior vice president of operations, said, "We would have to see what options we have that point to see if there's some alternative that we can do to satisfy their situation."

Rew said that about 88% of CRSP's transmission obligations sink outside its zone, leaving the remaining 12% exposed to rate increases because of SPP's treatment of PTP revenues. *Low water levels in the Colorado River* and the federal hydropower system also pose a risk, as the project's transmission system was built to move federal hydro, he told stakeholders during the MOPC and SPC meetings.

Staff and other RTO West-interested parties, working together, agreed that CRSP would maintain PTP revenue from its reservations to pay for facilities in its transmission zone. This would apply to service delivered either inside or outside the SPP RTO footprint, with the contractual or statutory load obligations distributed solely to the project.

Because SPP's tariff won't allow CRSP's replacement energy as an FSE, thus subjecting it to additional costs, staff and the other Western parties recommended the replacement energy be delivered to the CRSP zone and be subject to tariff provisions and charges.

Bruce Rew, SPP | © *RTO Insider LLC*

However, replacement energy delivered from CRSP's zone will be eligible for an FSE; ineligible transmission purchases will receive auction revenue or transmission congestion rights.

CRSP sells about 5.3 GW of power to customers in Arizona, Utah, Colorado, New Mexico, Nevada, Wyoming and Texas over transmission facilities either owned or leased by WAPA.

SPP is also evaluating options to pull in the implementation schedule for its *Markets+* offering in the Western Interconnection, an "RTO-light" market for those utilities not ready for full RTO membership. (See *Governance, Resource Adequacy Key to SPP's Markets+*.)

The grid operator has projected an initial phase establishing market rules and tariff language will take about 21 months, followed by another three years to develop the day-ahead market.

The *Western Resource Adequacy Program*, a key part of the Markets+ offering, has attained funding commitments to move the program forward, and SPP has replied to a FERC deficiency letter over its tariff filing, the RTO's Antoine Lucas told the SPC. Operations and forward-showing programs and systems will be implemented later this year, he said.

The SPC also approved a task force's recommendation to add changes needed to include competitive upgrades to project monitoring processes as part of its business practice related to transmission projects.

The Transmission Owner Selection Process Task Force has reviewed 19 key areas to improve the competitive project selection process. It has reached consensus on 12 areas. ■

Company News

NextEra Changes Leadership at FPL Subsidiary

Utility Battling Campaign Finance Violation Charges; Stock Drops

By Tom Kleckner

NextEra Energy CEO John Ketchum on Wednesday pushed back against allegations of campaign finance violations at the company's Florida Power & Light (FPL) subsidiary.

In a prepared statement made during the company's year-end earnings call, Ketchum told analysts that an internal review of *media reports* of alleged violations by FPL is "substantially complete."

"We believe that FPL would not be found liable for any of the Florida campaign finance law violations as alleged in the media articles," he said, basing his comment on "information in our possession."

Ketchum said the media coverage was used in a *subsequent complaint* filed in October by Citizens for Responsibility and Ethics at the Federal Election Committee. The ethics watchdog named names in its complaint and tracked contributions totaling $1.27 million to federally registered super PACs in 2020.

NextEra plans to seek dismissal of the complaint in the next few weeks, Ketchum said.

The complaint "primarily relies on media articles that allege certain violations … by various parties, including, by implication, FPL," Ketchum said. "We do not believe it is appropriate for a complaint such as this to move forward … we do not expect that allegations of federal campaign finance law violations taken as a whole would be material to us."

NextEra also *announced* that FPL CEO Eric Silagy plans to retire after 20 years with the company, 11 as the utility's top executive. Armando Pimentel, who retired from NextEra in 2019 as CEO of NextEra Energy Resources, will replace Silagy.

Silagy has denied any knowledge of the utility's alleged involvement in manipulating Florida elections, although leaked messages have shown he was in frequent and detailed communication with his senior staff about influencing a state senate race. Silagy served as senior vice president of regulatory and state governmental affairs before being named FPL's CEO.

Ketchum said NextEra wasn't making a "connection" between the allegations and Silagy's retirement but acknowledged the reports may have played a role.

"When you think about all the challenges that he had to overcome, with the hurricanes and high natural gas prices and inflation and supply chain and, you know, the media allegations and all those things, I think it took a toll on Eric that year," Ketchum said in a response to an analysts' question. "The way I look at it is it's a little earlier than I would have hoped Eric would have wanted to do it."

NextEra Energy's corporate headquarters in Juno Beach, Fla. | *© RTO Insider LLC*

Shares Plunge

The earnings discussion, leadership changes and NextEra's mixed results led to nearly a 9% drop in the company's stock price. Shares closed at $76.59 on Wednesday, down $7.31 from the previous close.

NextEra *reported* a fourth-quarter earnings of $1.52 billion ($0.76/share), compared to $1.20 billion ($0.61/share) a year ago.

For the full year, earnings were $4.157 billion ($2.10/share), up from $3.57 billion ($1.81/share) in 2021.

Operating revenue was up to $6.16 billion from $5.05 billion in 2021. However, analysts had expected $6.3 billion.

NextEra Energy expects 2023 earnings in the range of $2.98-$3.13 per share. The midpoint, $3.05 per share, is lower than the Zacks Consensus Estimate of $3.11.

Ketchum said the Inflation Reduction Act's passage leaves NextEra "better positioned than ever before to offer low-cost renewables and other clean energy solutions" beyond 2030. He said the company is extending its adjusted EPS growth expectations to $3.63-$4.00 for 2026.

"We will be disappointed if we are not able to deliver financial results at or near the top end of our adjusted earnings per share expectations ranges," Ketchum said. ■

Company News

Xcel to Pilot Long-duration Storage at Retired Sites

By Tom Kleckner

Xcel Energy on Thursday *announced* plans to develop long-duration storage systems at two retiring coal plant sites, part of an accelerating timeline for transitioning away from coal as a fuel resource.

The Minneapolis-based company has entered into definitive agreements with clean energy developer Form Energy to deploy its iron-air battery systems in a pair of pilot projects. Xcel said the storage technology will allow it to integrate more renewable energy into its system and maintain reliability as it continues to retire coal plants in the coming years.

"We are starting to get on a treadmill of shutting down our coal plants," CFO Brian Van Abel told financial analysts Thursday during the company's year-end earnings conference call.

The 10-MW/1,000-MWh multiday systems — capable of providing 10 MW of instantaneous power for up to 100 hours — will be installed at the Sherburne County Generating Station in Becker, Minn., and the Comanche Generating Station in Pueblo, Colo. Both projects are expected to come online as early as 2025 and are subject to regulatory approvals.

"Our partnership with Form Energy opens the door to significantly improve how we deliver carbon-free energy," CEO Bob Frenzel said in a statement.

The company remains on track to reduce carbon emissions 80% by 2030 and to deliver carbon-free electricity by 2050, Frenzel said. Pursuing advanced storage opportunities will "balance" Xcel's system needs.

Xcel *said* in October it would quit burning coal by 2031 when it retires the final Comanche plant. It plans to shutter the 1.1-GW Tolk Generating Station in West Texas in 2028, more than four years earlier than planned. (See *Xcel Energy to Quit Burning Coal in 2030*.)

The company *reported earnings* for the year of \$1.74 billion (\$3.17/share), up from 2021's performance of \$1.6 billion (\$2.96/share). Earnings for the fourth quarter came in at \$379 million (\$0.69/share), compared to \$315 million (\$0.58/share) for the same period a year ago.

The quarterly earnings were on par with Zacks Investment Research's consensus estimate; the quarterly revenues of \$4.05 billion exceeded the Zacks estimate of \$3.54 billion.

Xcel's share price closed the week at \$68.43, off just 13 cents from its pre-earnings close of \$68.56. ■

Rendering of battery arrays for renewable energy storage projects at two Xcel Energy coal sites. | *Form Energy*

Company Briefs

GM, LG Energy Cancel Plans for 4th US JV Battery Plant

General Motors and LG Energy Solution last week said they do not plan to move forward with a fourth U.S. battery cell manufacturing plant.

The companies' joint venture, Ultium Cells, said in August it was considering a site in New Carlisle, Ind., for a fourth battery plant that was expected to cost around $2.5 billion. However, LG Energy recently said discussions on the plant remain ongoing "but no decision has been made." GM could still proceed with plans to build a new plant with a new partner, sources said.

More: *Reuters*

Hyundai Unveils $8.5B Spending Plan amid EV Push

Hyundai last week announced it will invest $8.5 billion this year on electric vehicle research and development, as well as building a new plant in the U.S.

The company is targeting a 54% jump in EV sales in 2023 to 330,000 globally and said it wants its U.S. electric car sales to climb 150% to 73,000 to account for 9% of its U.S. sales.

Hyundai said in May that it is investing $5.5 billion to build an EV assembly and battery plant near Savannah, Ga., with the project expected to break ground this year.

More: *Bloomberg*

ACORE CEO Wetstone Stepping Down

The American Council on Renewable Energy (ACORE) last week announced that President and CEO Gregory Wetstone will step down after seven years with the organization.

"It has been a great privilege leading ACORE and helping position the renewable industry to deliver the clean energy future that Americans want and scientists demand," Wetstone said. "The time has come for me to move on to my next chapter. I know the talented ACORE staff will continue to drive progress working alongside the organization's stellar board of directors and its engaged and supportive members."

ACORE will begin a search for a replacement.

More: *ACORE*

Federal Briefs

EPA Denies Coal Ash Dumping Requests

The EPA last week denied six coal plants' requests to keep dumping toxic ash into unlined or inadequately lined pits.

The rules say that pits without legally compliant liners needed to stop receiving coal ash by April 2021, but many companies continued dumping ash in such pits and ponds. The six plants covered by the new decisions had argued they should not have to meet the deadline since naturally occurring clay, archaic liners or other conditions made their pits essentially as safe as impoundments with modern liners. In its denials, the EPA cited holes in the companies' arguments about the pits' safety and faulted the companies for failing to comply with other provisions of the rules.

Extensions to the deadline were denied at DTE's Belle River and Monroe plants in Michigan; the Coal Creek station in North Dakota; the Conemaugh plant owned by Talen Energy near Pittsburgh; the Salt River Project's Coronado Generating Station amid Native American reservations in Arizona; and the Martin Lake Steam Electric Plant in eastern Texas. The Apache Generating Station in Arizona was granted an extension on the condition it improves groundwater monitoring.

More: *Energy News Network*

Freeport LNG Seeks Approval to Begin Restart

Freeport LNG last week asked FERC to allow preliminary work to restart its 2.38 Bcf/d terminal in Texas, according to filings.

FERC staff published a request submitted by Freeport LNG requesting permission to begin reintroducing liquefied natural gas (LNG) through its Loop 1 system. The facility has been idled since a June explosion. If approved, the company could begin an 11-day process to cool down its transfer piping so that it can move LNG to dock one and restart boil-off gas management.

The timeline could mean activities to restart liquefaction equipment and other parts of the facility could follow in the first week of February.

More: *Natural Gas Intelligence*

TVA Plans Tx Upgrades in TN, NC

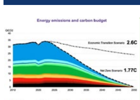
The Tennessee Valley Authority last week said it plans to spend $28 million on transmission upgrades in Polk County, Tennessee, and Cherokee County, North Carolina, to help improve reliability.

TVA is proposing to build a switching station and 27 miles of new power lines to connect with the Appalachia Dam and extend power to the southeast. The expenditure is part of more than $2 billion that TVA plans to spend on transmission improvements.

TVA is seeking public input through Feb. 20.

More: *Chattanooga Times Free Press*

National/Federal news from our other channels



BNEF: Net Zero Targets Only Limit Climate Change to 1.77 Degrees

NetZero Insider

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

State Briefs

CALIFORNIA

ZEV Sales Near 19% of All New Car Sales in 2022

Data from 2022 showed that 18.8% of all new cars sold in the state were zero-emission vehicles (ZEVs), according to the Energy Commission.

The highest selling ZEVs were the Tesla Model 3 (94,683) and Model Y (93,872). In total, 1,835,429 ZEVs were sold.

The commission also said that 40% of ZEVs sold in the U.S. were sold in California.

More: *California Energy Commission*

IDAHO

Duke Energy Begins Operation of State's Largest Solar Plant

Duke Energy Sustainable Solutions last week announced that its 120-MW Jackpot Solar project in Twin Falls County is now operational.

The largest solar facility in the state will provide energy to Idaho Power through a 20-year power purchase agreement.

More: *Renewable Energy Magazine*

ILLINOIS

Henry County Approves Community Solar Project

The Henry County Board last week unanimously approved a special-use permit for a 5-MW community solar project.

EnPower Solutions owns the property, while Common Energy will sell 800 to 1,000 subscriptions to the project.

More: *Quad-City Times*

MINNESOTA

House Passes Bill Requiring Carbon-free Electricity by 2040

The House of Representatives last week voted 70-60 to require the state's utilities to get all their electricity from carbon-free sources by 2040.

Under the bill, utilities would need to increase the amount of their electricity generated from renewable sources to 55% by 2035. It also sets a series of benchmarks utilities would be required to meet, culminating with 100% of their electricity coming from carbon-free sources by 2040.

A companion bill also passed out of a Senate committee and could go before the full Senate as soon as this week.

More: *MPR News*

NEW MEXICO

Bill Would Require New Homes to Include Solar, EV Charging

Democratic Sen. **Bill Soules** last week introduced a bill that would require all new homes to have solar panels and EV charging stations.

Any new home would have a photovoltaic system that would provide at least 1W per square foot of heated area, along with at least one EV charging station.

The Home Builders Association expressed concerns about the bill, saying it would drastically increase building costs, which would be passed onto the home buyer.

More: *KRQE*

Threats over High Natural Gas Bills Shutter Deming City Hall

The city of Deming's municipal offices were abruptly closed to the public on Jan. 25 in response to threats against city staff after high utility bills arrived for about 6,000 customers who purchase natural gas through the city.

Deming Police Chief Clint Hogan said that an unspecified number of "telephonic threats" targeted employees around 10:42 a.m. and recommended placing the municipal building on lockdown. The city announced that offices would stay closed until Jan. 30, as well as an emergency relief program under which the city will eat 65% of those bills.

Although city officials had warned at a Jan. 10 town hall that the next round of bills would be "outrageous" after per-unit prices soared past $3, residents and businesses reacted with shock after being billed hundreds or even thousands of dollars.

More: *Albuquerque Journal*

NORTH CAROLINA

Cooper Names Recktenwald Climate Change Policy Adviser

Gov. Roy Cooper named Bailey Recktenwald as the climate change policy adviser for the governor's office, effective Jan. 9.

Recktenwald is responsible for policy development, project management, stakeholder engagement, strategic planning and other duties to support Cooper's climate agenda.

Before joining the governor's office, Recktenwald served as the chief strategy officer at the state's Department of Environmental Quality.

More: *Coastal Review*

SOUTH CAROLINA

Silicon Ranch Gets Zoning Approval for Lamberttown Solar Farm

The Georgetown County Council last week approved a zoning change that will allow Silicon Ranch Corp. to build a 2,000-acre solar farm in the Lamberttown community.

The plans call for Silicon Ranch to build and operate two solar facilities on the property. They will each have a capacity of 100 MW and will be owned and operated by SR Lambert I and SR Lambert II. The two facilities will sell their energy to Santee Cooper and Central Electric Power Cooperative.

More: *Georgetown County News*

TEXAS

CPS Energy to Phase Out Coal by 2028

The CPS Energy Board of Trustees last week voted 4-1 to approve a new energy mix that will see the utility phase out its use of coal by 2028.

Under the plan, CPS Energy will shut down Spruce 1 by 2028 (pending ERCOT approval) and convert Spruce 2 to a natural gas plant by 2027.

The utility will add about 4,928 MW of capacity over the next seven years, including 1,380 MW from combined cycle natural gas and about 800 MW from reciprocating internal combustion engines that run on natural gas or diesel. Another 500 MW will come from wind, 1,180 MW from solar, and 1,060 MW from lithium battery storage.

More: *San Antonio Report*

VIRGINIA

Corporation Commission Approves Roanoke Gas RNG Project

The State Corporation Commission last week approved a plan by Roanoke Gas to convert biogas from a sewage treatment plant into natural gas.

Under the plan, biogas at the Western Virginia Water Authority's Roanoke Regional Water Pollution Control Plant will be pumped to a network of above-ground tanks, where a separation system will be used to refine it to pipeline-quality natural gas that will be transported to a nearby Roanoke Gas line.

Roanoke Gas said the facility will help insulate customers from significant price increases by giving the company a locally produced supply that would not be subject to nationwide trends.

More: *The Roanoke Times*

House Votes to Repeal Clean Cars Law

The Republican-led House of Delegates last week voted 52-48 to pass legislation that would repeal a law tying the state to California's vehicle emissions standards, which are set to ban the sale of new gas-powered cars in 2035.

House Bill 1378, sponsored by Del. Tony Wilt, likely faces an uphill battle in the Senate, where Democrats have killed several Republican bills aimed at the same goal.

In 2021, the General Assembly passed legislation that coupled the state's vehicle emissions regulations with those set by the California Air Resources Board. Last year, CARB issued a new rule that will require all new cars sold in the state be zero-emission beginning in 2035.

More: *Virginia Mercury*

WYOMING

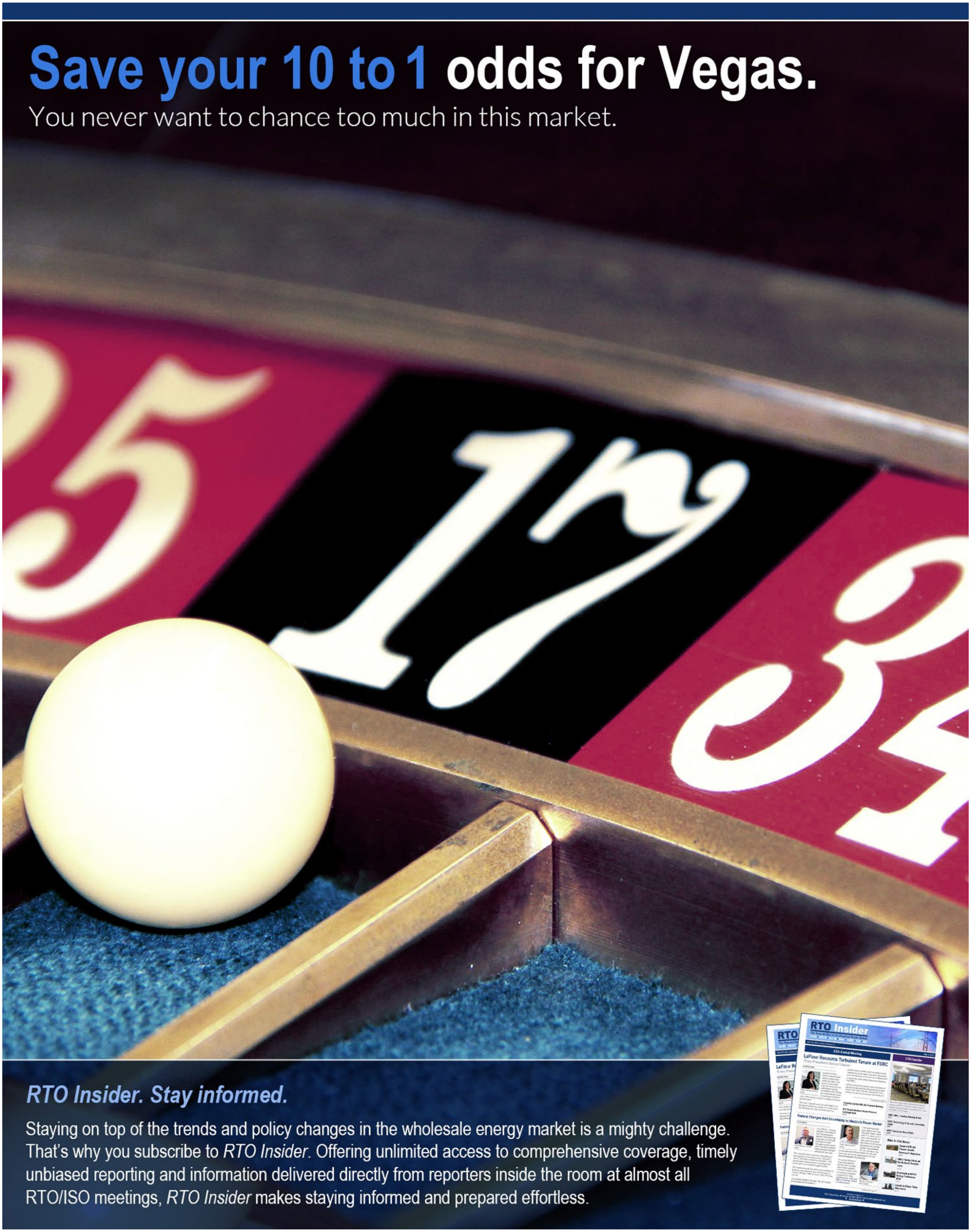
Effort to Repeal, Reform Rooftop Solar Payments Advances

The Senate Corporations, Elections and Political Subdivisions Committee last week voted 3-2 to repeal mandatory net-metering for residential and small business rooftop-solar power generation, while also reforming the program for those grandfathered in.

The measure would repeal a statute that requires regulated utilities to credit or pay residential and small business customers for surplus electricity that's redirected onto the grid. The repeal would go into effect July 1, 2024. Net-metering arrangements would be honored until July 1, 2039 for customers with solar panels installed by the repeal date.

The bill would also give authority to the Public Service Commission to determine net-metering compensation rates and allow utilities to potentially tack on extra charges for rooftop solar customers remaining in the system.

More: *WyoFile*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