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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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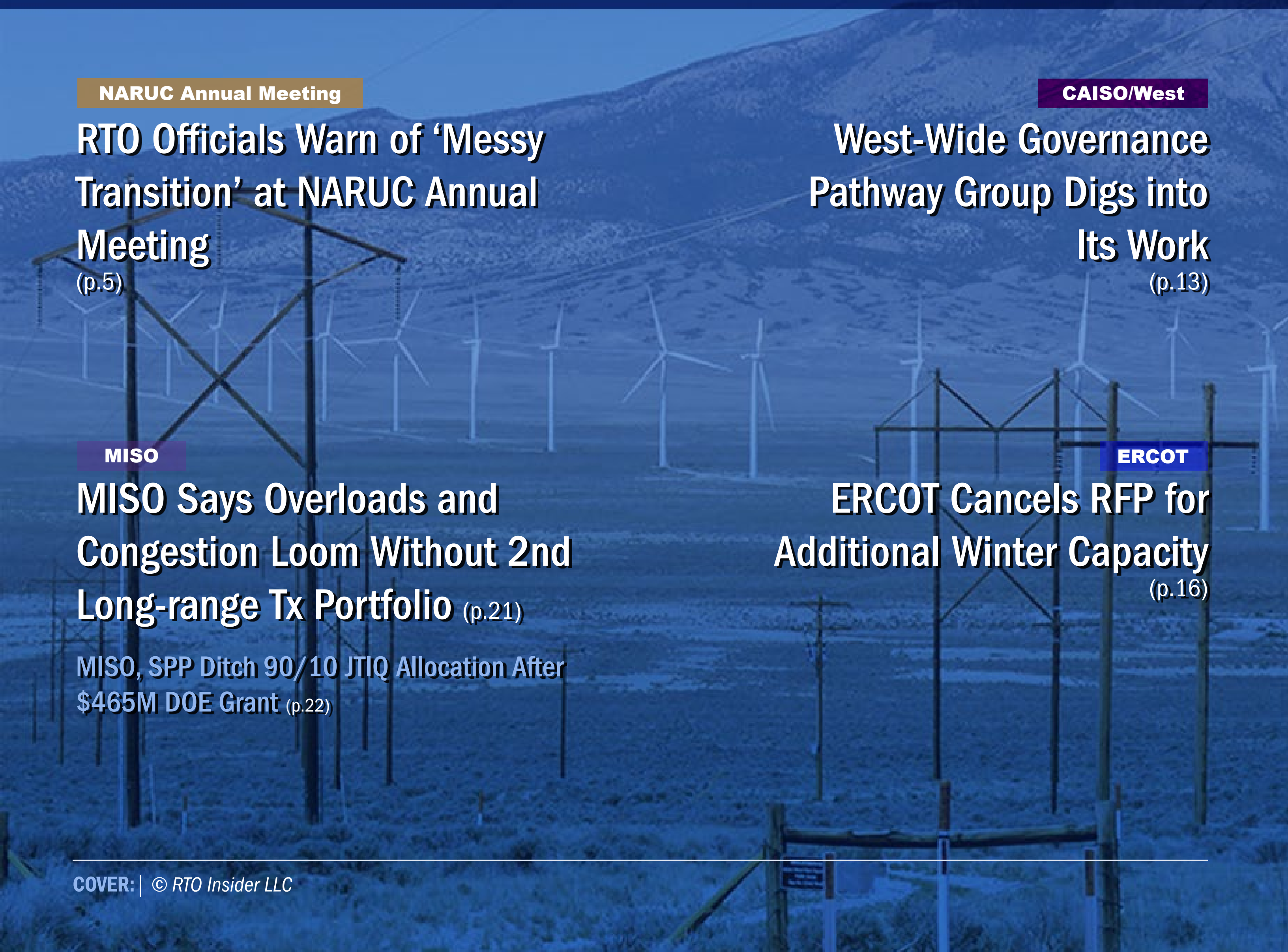

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Stakeholder Soapbox

Let the Market Determine the Fate of EVs

By Kenneth W. Costello

Advocates of various energy technologies have long argued that major barriers, either government or market derived, stifle the development of their favored technology. They then infer that the current level of their preferred technology is suboptimal, necessitating some form of governmental intervention.

That seems to hold true for New Mexico Gov. Michelle Lujan Grisham, who wants state tax credits and mandates on the purchases of electric vehicles. New Mexico already has a stringent clean car rule that requires that by 2031, 82% of all new vehicles delivered to the state be zero emission. Her agenda is a double whammy for gasoline/diesel-powered vehicles: Make EVs more economically attractive with taxpayer-funded subsidies and restrict the number of gasoline/diesel-powered vehicles New Mexicans can buy. She is essentially forcing EVs on New Mexicans faster than what they prefer.

Perhaps the most pathetic part of her agenda is that she hopes to trim down the number of gasoline/diesel-powered vehicles in the state without knowing whether that is what the residents of New Mexico want. (Car owners are wary of EVs for various reasons, including: their high upfront costs; range anxiety, i.e., their fear of not making it to the next charging station; and their inherent skepticism of new technologies.) How arrogant is that? She is telling New Mexicans that as governor, she knows better what types of vehicles they should purchase than they do. She is ignoring the wishes of her constituents to purchase different vehicles: Today, only about 1% of the vehicles in New Mexico are EVs.

She desires to fundamentally reshape the car industry via regulations, mandates and subsidies. Added to the insult is her requirement that taxpayers pay for her "all-electric" scheme when the majority of residents don't stand to benefit.

So far, purchasers of EVs are mostly in the high-income category, and that will likely hold for the foreseeable future. That means tax credits and other subsidies will benefit the well-to-do and be paid for by folks who are less financially well off. One study remarked that "The US academic literature indicates that up to 90% of EV purchase incentives adopted by the federal government have flowed to the richest one-fifth of households."[1] This also suggests many of the purchasers would have bought an EV in the absence of government incentives. This behavior means (1) the reduction in greenhouse gas (GHG) emissions attributable to the incentives are overstated and (2) the incentive is essentially a windfall gain to higher-income households paid for by less-well-off ones.

New Mexico Gov. Michelle Lujan Grisham | *Gov. Grisham*

And what is in it for the residents of New Mexico and other jurisdictions inducing EV purchasers with subsidies and mandates? Zilch! What almost always gets ignored is the fact that no matter how many EVs New Mexicans or people in other jurisdictions buy, the effect on climate change is negligible.

A mandate to require that a certain percentage of vehicles be EVs represents a policy with intrinsic distortions. It is a highly blunt instrument, draconian and expensive relative to other ways to mitigate GHG emissions (which is the manifested rationale for the governor's all-electric mandate).

Probably most serious, banning or artificially restricting goods or services reflects governmental action that dictates consumers find a substitute that presumably is inferior to the alleged objectionable product that is banned, or else such action would not be necessary. A ban forces consumers to do something they otherwise would not do. For example, vehicle owners could hang on to their old, less fuel-efficient vehicles longer than otherwise — a perverse outcome that could lead to higher GHG emissions.

By reducing options for vehicle owners, driving will become more expensive in New Mexico. Perhaps this is the intent of those who are anti-car. As warned by energy expert Mark Mills of the Manhattan Institute, "they're coming for your cars."

Government controls over GHG emissions directly affect goods and services, such as electricity and transportation, whose costs will likely escalate. If controls include banning or severely restricting fossil fuels like gasoline, the costs could be substantial. We have an abundance of fossil fuels at affordable prices, which explains why over 80% of the world's energy still comes from fossil fuels. This raises the question of whether we want to or can wean ourselves from fossil fuels over the next two or three decades without suffering severe economic consequences.

The governor's actions presume that EVs are a winning technology — but this is highly presumptuous, as there is much uncertainty over the future of EVs. Mandates carry risks. Mandates require policymakers to pick winners and losers, which is inherently almost

Stakeholder Soapbox

impossible, and often results in failure, given the limited knowledge of policymakers (which, of course, they don't want to acknowledge) and their propensity to serve special interests. The problem is particularly acute for new technologies with a high level of uncertainty over cost and performance. For example, a policy that mandates EVs as a preferred option can turn out disastrously if the price of gasoline falls sharply or if EVs fail to develop economically and technically as advocates hope.

A better way to make EVs more attractive to consumers is to have them compete against gasoline/diesel-powered vehicles. When regulating or legislating away their main competition, it becomes more likely that EVs will continue to be inferior to gasoline/diesel-powered vehicles. This is just one example of the unintended consequences sprung from a policy whose prime intent is to promote a particular technology.

What is particularly perplexing is the rationale behind the governor's intent to accelerate the purchase of EVs by New Mexicans through tax credits and mandates. She argues that the tax credits will make EVs more affordable to middle- and low-income households. But one cannot ignore the evidence showing that the subsidies will disproportionately benefit the wealthy at the expense of those less well off. So far, 90% of EVs in the U.S. have been purchased as a second or third car by high-income households.[2]

It's not even clear that replacing gasoline/diesel-powered vehicles with EVs will have a positive environmental effect. Similar to many other batteries, the lithium-ion cells that power most electric vehicles rely on raw materials (like cobalt, lithium and rare earth elements) that have triggered grave environmental and human rights concerns. Cobalt has been especially problematic. The environmental effect, of course, also depends on what energy sources are used to produce electricity. Currently, much of the electricity generated at night (when charging occurs for most EVs) comes from fossil fuels.

Even if EVs lower GHG emissions, studies have shown they are an inefficient way in terms of the costs per unit of avoided emissions. Other alternatives, such as nuclear power and natural gas are more cost-effective. One study claimed that EVs are among the most expensive tools government can use to lower GHG emissions, measured as dollars spent to achieve a given amount of GHG reduction.[3] What would seem to be a preferred social policy is to impose an efficient tax on GHG and tailpipe emissions.

I believe that what is driving EV frenzy is the anti-fossil fuel agenda or virtue signaling (by both EV purchasers and EV advocates). EV advocates probably know EVs would have a minuscule effect on climate change but long to see the extinction of fossil fuels; I can't think of a more plausible explanation.

To wit, most climate activists view fossil fuels as a barrier to achieving deep-decarbonization targets deemed essential to protect against alleged catastrophic climate change. They consider electrification of buildings and transportation with clean energy sources as part of a policy portfolio to achieve these targets. What they don't say is that their proposals for government intervention will fail a cost-benefit test and are regressive by benefiting the well-to-do at the expense of others. How can they then defend their pro-EV advocacy with such anti-social results?

I want to conclude by saying that I think EVs are a remarkable technology that I hope will succeed on its own without government assistance. Both for equity and economic-efficiency reasons, government inducements — whether to hasten the number of EVs or charging stations through perverted policies — are a bad idea. Governments can better spend taxpayers' monies. EVs have a promising future. Technological advancements in batteries and the other sides of production, as well as in charging stations, will ultimately decide the fate of EVs, as they will determine consumers' demand for EVs and manufacturers' profits from EVs. Their success is more likely if government steps out of the way and allows EV providers to address market demands to lure consumers with price reductions and better vehicle performance — not with subsidies and mandates. ■

Kenneth W. Costello is a regulatory economist and independent consultant.

[1] Fraser Institute, https://www.fraserinstitute.org/sites/default/files/review-of-electric-vehicle-consumer-subsidies-in-canada.pdf.

[2] Energy Institute at Hass, https://energyathaas.wordpress.com/2021/09/20/three-facts-about-evs-and-multi-vehicle-households/.

[3] International Monetary Fund, https://www.imf.org/en/Publications/fandd/issues/2019/12/the-true-cost-of-reducing-greenhouse-gas-emissions-gillingham.

NARUC Annual Meeting

RTO Officials Warn of 'Messy Transition' at NARUC Annual Meeting

New NARUC President Fedorchak Announces Gas-electric Coordination Initiative

By Ayla Burnett

From left: PJM CEO Manu Asthana; MISO CEO John Bear; NERC CEO Jim Robb; and North Dakota PSC Commissioner Julie Fedorchak | © *RTO Insider LLC*

LA QUINTA, Calif. — As pressure grows to decarbonize the electricity sector, grid operators are increasingly grappling with how to coordinate the retirement of traditional resources with the introduction of new non-emitting resources — all while ensuring reliability and affordability.

Challenges of the grid's transition was a running theme of the discussions among utility regulators and power industry stakeholders at the National Association of Regulatory Utility Commissioners' Annual Meeting held in the Southern California desert from Nov. 12 to 15.

"In these discussions you get the question of what keeps you up at night," MISO CEO John Bear said. "The transition … is probably the biggest concern that we have."

In a Nov. 14 panel, RTO/ISO executives identified the litany of challenges their organizations face as they attempt to retire thermal generation and integrate renewables onto the grid.

"We have to keep the lights on and keep the power affordable through the transition," PJM CEO Manu Asthana said. "The big difference is the new resources that are coming on are not predictable in the same way that the old resources were."

With the retirement of thermal generation comes the challenge of ensuring there are enough dependable resources to fill the gap when weather-dependent renewables can't serve load. The introduction of new technologies has been slow, and if traditional resources are retired too soon, grid operators fear the worst.

"That's probably one of my biggest concerns, is that we will let these resources that we have, that we use today, retire and not have the replacement resources come in time," Asthana said. "We just can't let that happen."

Asthana pointed out that PJM is on track to retire about 40 GW of resources by 2030; Calpine's Joseph Kerecman told *RTO Insider* that may be an understatement. (See *PJM Whitepaper to Highlight Future RA Concerns*.)

The solution, the CEOs said, is to keep some traditional methods of generation, like natural gas plants, on the grid as long as possible in combination with renewables to ensure reliability.

"There's a lot of pressure to not build gas infrastructure, but gas is the marginal fuel in our markets," Asthana said. "We're approaching this intersection where we know we have to decarbonize the system, but I think we are at risk of not doing so in an orderly fashion."

NERC CEO Jim Robb emphasized another solution to make a smoother transition: getting better standards in place for inverter-based resources. He noted that while inverter-based resources are currently "grid-following," they will have to form the grid when they start making up 40 to 60% of the generation mix.

"That's the path toward a carbon-free grid: having grid-forming technology through power electronics. But we're not there yet," he said.

Greater Gas-electric Coordination Needed

Robb said the electric industry is the largest consumer of natural gas, and with the increasing demand for electrification comes a greater need for coordination between the electric and gas sectors.

"If we continue to just build out the electric sector, but we're not paying attention to the fuel infrastructure behind it, we're going to run into a lot of issues," Robb said.

During a Nov. 15 panel, commissioners, regulators and strategists emphasized the need to view and operate the grid as a single entity.

"There's two separate grids right now," said Jason Ketchum, vice president at ONE Gas, a Oklahoma-based utility that also serves customers in Texas and Kansas. "There's a gas grid, and there's an electric grid, and we need to start talking about the energy grid."

Diverting from many of the week's climate-focused conversations, Ketchum emphasized the importance of listening to the customer and recognizing that people in some communities may not have the interest or capability to moderate their lifestyles in the interest of burning less gas.

"We serve a pretty wide geographic area, and a lot of our communities are different," Ketchum said. "Some are more focused on environmental issues; others are more focused on affordability."

Georgia Public Service Commissioner Tricia Pridemore, who moderated the panel, asked "if the answer to all of this" was to build more pipelines.

Not necessarily, Ketchum said: Focus on delivering whatever the best asset is to the customer in any given area. But he also emphasized gas as an important economic driver.

"There's a lot of parts of our region that don't have gas that can't grow economically," he said. "It's a great opportunity to locate assets in areas that can really help out those communities."

Getting into GEAR

North Dakota Public Service Commissioner Julie Fedorchak, who was elected NARUC president during the conference, announced a new initiative called Gas-Electric Alignment for Reliability (GEAR).

Led by Pridemore, NARUC's newly elected vice president, GEAR will bring together a task force of regulators, utilities, grid and pipeline operators, and gas producers and suppliers to help better coordinate the gas and electric industries. Energy officials are hopeful that GEAR will initiate meaningful progress toward greater gas-electric coordination to meet the country's reliability and clean energy needs.

"This is going to be a messy transition, almost guaranteed," PJM's Asthana said. "But I'm almost certain we're going to solve this problem." ■

FERC/Federal News

DOE Proposes Expanding NEPA Exclusions for Clean Energy, Transmission

By James Downing

The U.S. Department of Energy on Thursday proposed *revisions* to its regulations under the National Environmental Policy Act that would expand the scope of "categorical exclusions" for transmission and clean energy.

The exclusions would apply to projects that are shown to not have a significant environmental effect. It would create a new exclusion for energy storage projects within previously disturbed or developed areas, while changing exclusions for solar energy and transmission.

DOE reasoned that upgrading lines can prevent the construction of new ones, with the Notice of Proposed Rulemaking (NOPR) highlighting reconductoring as a means of capacity expansion, which can increase the amount of renewable energy on the grid.

"Improvements to capacity and efficiency can help to ensure reliability, reduce costs to consumers and reduce [greenhouse gas] emissions associated with electricity generation, transmission and distribution," said the notice in the *Federal Register*.

Rebuilding transmission lines is currently exempted, but only up to 20 miles. The proposal would remove that mile limit. The department reasoned that the environmental impact of a line is not related to its length.

It also would expand the exclusion for relocating segments of a line to existing rights of way or previously disturbed or developed lands. Regulations currently include language limiting relocation exemptions to "minor" relocations of small segments; the proposal would remove the word "minor."

The storage exemption applies to electrochemical batteries and flywheels within previously disturbed or developed areas, or within small sites near such areas.

The current categorical exclusion for solar is limited to projects of 10 acres or below, but DOE said acreage is not a reliable indicator of environmental impact and would remove that limit in the proposal. Projects larger than 1,000 acres on previously disturbed or developed land have not had significant environmental impacts, it said.

DOE expects that the new exclusions will save it money and time, while improving the reliability and resilience of the electric grid. Expanded electricity generation that helps to reduce greenhouse gas emissions is another benefit.

The department is taking comments on the proposal through Jan. 2.

Speaking after FERC's open meeting Thursday, Chair Willie Phillips said that the proposal would have more impact on DOE's transmission siting authority. The commission has its own pending NOPR implementing its backstop siting authority granted by the Infrastructure Investment and Jobs Act. (See *FERC Backstop Siting Authority Runs into Opposition from States*.)

DOE's proposal was welcomed by American Council on Renewable Energy President Gregory Wetstone in a statement.

"A dramatic increase in renewable energy and transmission infrastructure is needed to enhance reliability, lower energy costs and maximize the benefits of the Inflation Reduction Act," Wetstone said. "A key barrier is the often lengthy siting and permitting process. ACORE supports the use of categorical exclusions for projects that will produce a cleaner grid and not adversely impact the environment. This mechanism improves siting and permitting while maintaining NEPA's core environmental provisions." ■

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FERC/Federal News

Will DOE's Tx Needs Study Spur New Regional, Interregional Lines?

Department Incorporated 330 Industry Comments on Draft into Final Report

By K Kaufmann

A key difference between the *draft* National Transmission Needs Study the Department of Energy released in February and the *final version* issued Oct. 30 is a new section in the introduction spelling out what the goals of the report are and, equally important, what they are not.

"The objective is to identify pressing transmission needs across the nation," said Jesse Schneider, a policy adviser in DOE's Grid Deployment Office (GDO), which authored the report. "However, the study does not prescribe any specific transmission solutions to meet those needs."

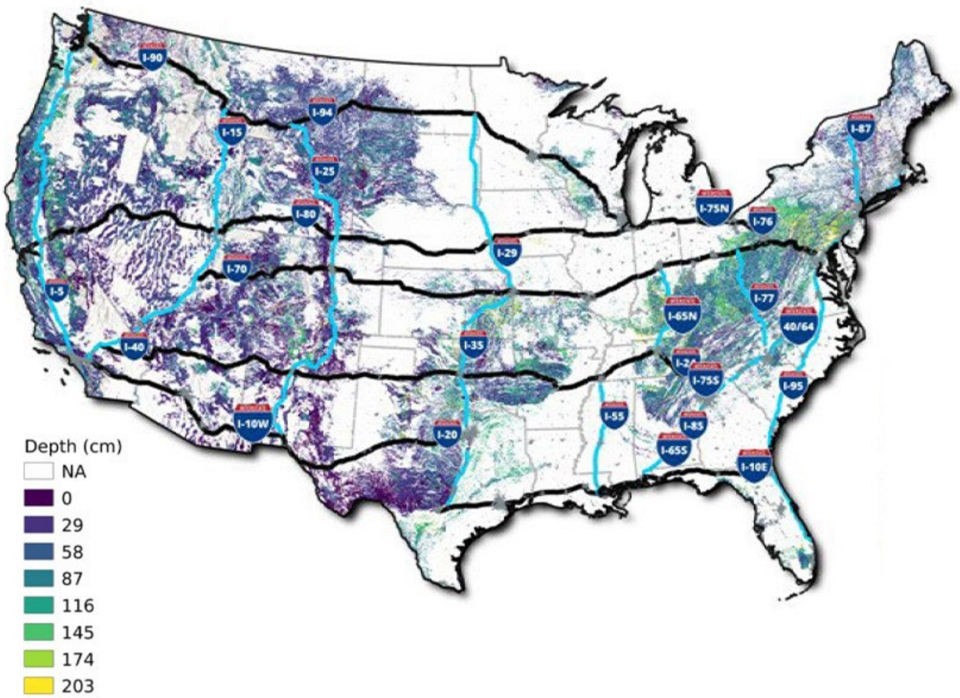
Speaking during a recent webinar on the report, Schneider further stressed "the study findings are intended to inform department transmission priorities, including implementation of funding programs, technical assistance or broader transmission planning programs." The report is not intended "to supplant or presuppose any existing transmission planning activities," he said.

Similarly, while the study does break down transmission needs by region, that analysis will be used to "inform" but not designate any National Interest Electric Transmission Corridors (NIETCs) — areas where transmission constraints and congestion could be improved with federal funding and accelerated permitting. (See *What Are National Interest Transmission Corridors and Why Do We Need Them*?)

DOE issued a request for information on the process for designating NIETCs in May and, as with the Needs Study draft, received a range of comments. In her opening remarks at the Nov. 8 webinar, GDO Director Maria Robinson said further guidance on NIETC designation would be released by the end of the year. (See *States, RTOs Caution DOE on Transmission Corridors*.)

Separate from NIETCs, DOE sees the Needs Study as a resource that can be used to encourage entities "to revise their planning processes to incorporate these findings, including consideration of a wider range of transmission benefits [and] portfolios of transmission project evaluation, rather than individual project evaluation," Schneider said.

Broader planning perspectives also might include "scenario-based planning with longer time horizons to incorporate alternative transmission solutions including grid-



The National Transmission Needs Study looks at possibilities for siting underground transmission lines along existing highway rights-of-way. The dark blue areas here note rugged terrain or shallow bedrock where undergrounding would be difficult and expensive. | *NREL*

enhancing technologies, as well as weather data [that] better reflect future extremes," he said.

The need to explain the study's goals and how it should and shouldn't be used was raised by a number of the 58 groups and individuals who submitted a total of 330 comments on the draft Needs Study. The comments were summarized, with the department's responses, in an 80-page appendix to the final.

The range of comments and the resulting revisions made to the final study reflect the complexities of grid planning as the U.S. generation mix moves toward cleaner, renewable resources.

"I think it does send a clear message," said Rob Gramlich, president of industry consultant Grid Strategies. "It's a well-done and thorough report citing many dozens of studies. So, I think, as a pure piece of analysis and information, it makes a very strong case. And it is from the Department of Energy, with the authority that entails … and is supported by all the national labs, so that gives it a lot more credibility than just a report."

The study's topline findings were no surprise, as Energy Secretary Jennifer Granholm said in a press call preceding the release. "We need to seriously build out transmission in order to improve reliability and resilience, and of course, to lower energy costs and relieve congestion on the grid."

The study also finds "that of all the different configurations of transmission deployment, interregional transmission results in the largest benefits," Schneider added during the Nov. 8 webinar, with the caveat that "transmission needs will shift over time."

The Comments

The report's broad and general approach — and the department's insistence on not providing solutions — left some commenters dissatisfied. Utilities, RTOs and transmission developers all argued the report omitted projects and circumstances specific to their transmission planning and operations.

New York Transmission Owners (NYTO), a util-

FERC/Federal News

ity stakeholder group in NYISO, said the report should include four of its latest projects, which are aimed at alleviating price differentials between New York City and upstate areas, an issue raised in the draft.

PJM staunchly defended its performance during the winter storm of February 2021, commonly referred to as Winter Storm Uri, noting it provided "unprecedented amounts of power" to neighboring regions and that any limits in interregional transfers were due to "constraints in neighboring systems."

ERCOT, on the other hand, urged DOE to treat the effects of Uri as outliers, asserting the report's call for more interregional transmission to connect Texas to surrounding areas is overstated, given system upgrades it has undertaken since the storm.

DOE's decision to base the report on existing studies, rather than fresh research — and the resulting underlying assumptions — was another flashpoint. While the draft referenced more than 50 reports, DOE was deluged with recommendations for other studies to be included, resulting in the final version reviewing and citing more than 100 reports.

Given the study's strong focus on interregional transmission, the National Renewable Energy Laboratory's *Interconnections Seam Study* — which looked at the benefits of interregional connections — was one of the more surprising omissions from the draft, but it was included in the final. Other additions include MISO's Long-Range Transmission Planning Process and CAISO's 2022-2023 Transmission Plan.

A lack of up-to-date information on transmission needs on tribal lands was another gap in the draft, according to comments from the Blue Lake Rancheria Tribe, in Northern California. In this case, DOE tapped a still-unpublished survey on tribal access to reliable electricity, which found an estimated 54,000 Native Americans, including Alaska Natives, live without electricity, the majority of them in the Navajo and Hopi nations.

Of those surveyed, 23% do not have access to a centralized power grid, and 65% said existing grid infrastructure could be extended to tribal lands, the report said in a new section on tribal transmission needs.

Multiple commenters also took issue with DOE's base case for anticipating and modeling future transmission needs, predicting high levels of renewable energy coming onto the grid, but only moderate load growth. Consolidated Edison pointed to the potential effect on demand spurred by New York's Climate Leadership and Community Protection Act as an example of ambitious state legislation that could drive load growth.

The law calls for New York to cut its greenhouse gas emissions 85% by 2050, with an interim goal of a 40% reduction by 2030.

Advocacy nonprofits similarly called for DOE to factor in the effect on renewable energy and load growth of the Inflation Reduction Act's clean energy incentives and the EPA's vehicle emission standards, which are expected to accelerate adoption of electric vehicles.

The Edison Electric Institute (EEI) and Public Service Enterprise Group (PSEG) faulted DOE for not taking into account FERC's proposed rules on transmission planning and cost allocation. According to the Needs Study, EEI argued the proposed reforms "will encourage efficient, cost-effective transmission investment."

DOE responded to EEI and PSEG by noting the Needs Study is focused on the physical limitations of the transmission system, "not jurisdictional or regulatory limitations." FERC rulemaking, therefore, is deemed "out of scope," DOE said. The department does acknowledge the likely effect of state and federal law, adding modeling of high renewable, high load growth scenarios to the final report.

For example, the study shows the Plains region (roughly corresponding with SPP) would need up to 119% more regional transmission under a moderate load growth, high renewable scenario, but possibly over 400% more in a high load growth, high renewable case.

The Impact

As originally authorized in 2005 amendments to the Federal Power Act, the Transmission Needs Study was called the Transmission Congestion Study, looking only at congestion on the grid. But the Infrastructure Investment and Jobs Act (IIJA) expanded the scope of the report to encompass future needs as well as congestion.

As the first such report, the Needs Study was released as part of a series of DOE announcements of new transmission programs funded by the IIJA, highlighting the department's role as a catalyst for transmission expansion. DOE is using $1.3 billion in IIJA funds to sign on as an anchor off-taker for three interstate transmission projects, chosen in part based on regional analyses in the Needs Study. (See *DOE to Sign up as Off-taker for 3 Transmission Projects*.)

DOE also recently awarded $3.46 billion in IIJA funds to 58 grid improvement projects, with the largest award, $464 million, going to five transmission lines in *MISO* and *SPP*'s joint targeted interconnection queue (JTIQ) portfolio. Reflecting the Needs Study's call for a portfolio approach to grid planning, the projects are aimed at improving interregional connections and transfers along the MISO-SPP seams. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

The report's effect outside the department seems more uncertain, especially given the strong regional and local bias in the comments.

On the one hand, the study's regional profiles are one of its strong points, laying out where more regional and interregional transmission could improve resilience and bring low-cost renewable power to urban and other areas with high electricity rates.

The study's approach here is aligned with how RTO grid planning appears to be evolving toward the portfolio approach DOE advocates, as seen in the MISO-SPP JTIQ projects and PJM's Regional Transmission Expansion Plan Window 3 solicitation. That initiative resulted in PJM recommending a range of projects to expand its system for new renewable generation as fossil fuel plants retire. (See *PJM Recommends $5B in RTEP Transmission Projects*.)

But the study also notes the majority of transmission projects that have been built in recent years are smaller lines aimed at improving local reliability. The proportion of overall transmission installed to address system reliability needs has grown from 44% in 2011 to 74% in 2020. Interregional projects that can provide multiple benefits beyond reliability — such as getting more cheap, renewable power online — still face formidable obstacles, including permitting and financing.

Gramlich sees the report as one piece of an incremental process — including DOE funding, NIETC designation and FERC rulemaking — that could drive change in transmission planning, permitting and construction.

"The report could encourage state and federal regulators to get busy … with interregional [transmission]," he said. "It can also encourage private developers — utilities or independent developers — to work on lines. … I would think developers building in the transmission [regions] that were highlighted in the report would get a boost with all of the stakeholders and all the utility off-takers or other subscribers to transmission lines. I would think this report would be meaningful for them to encourage their participation." ■

FERC/Federal News

FERC Enforcement Report Details One Closed Probe into Winter Storm Uri

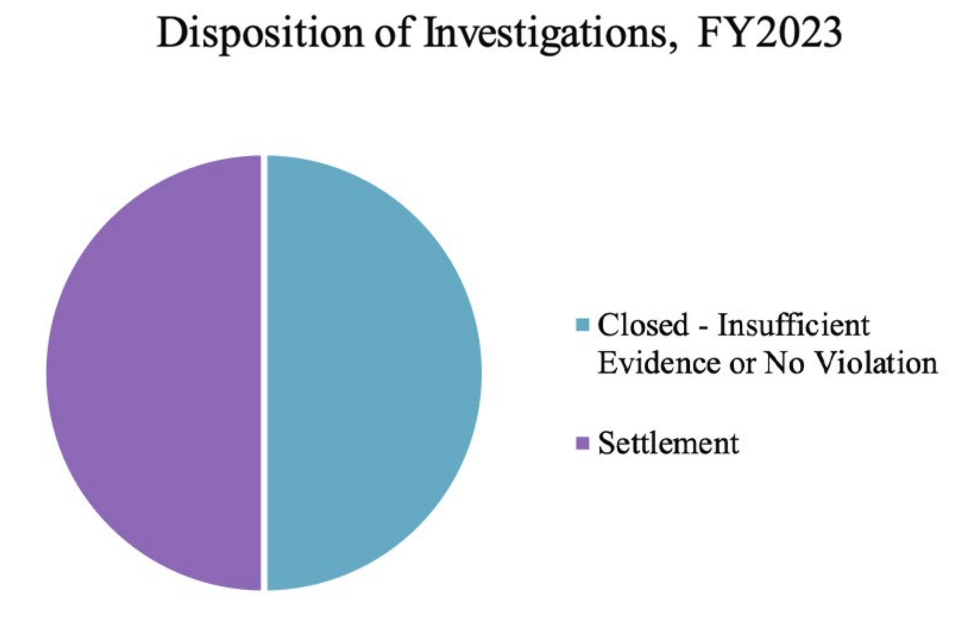
Phillips Says Others Ongoing

By James Downing

WASHINGTON — FERC on Thursday released its *17th Annual Report on Enforcement*, which showed that it has closed down one market manipulation probe into the events around February 2021's Winter Storm Uri.

The commission still has open, nonpublic investigations into the events around Uri, which led to massive blackouts in Texas where hundreds died and roiled natural gas markets around the country, leading to billions in extra costs for consumers.

"I cannot talk about them," FERC Chair Willie Phillips said at his post-meeting press conference. "But hear me: For those people who had market manipulation, who committed market manipulation, or if there was any fraud that was imposed upon our consumers — the Federal Energy Regulatory Commission, the Office of Enforcement ... will find you, we will punish you, and you will pay the price."



Finished investigations in fiscal year 2023 | *FERC*

The investigation FERC closed without action came from a referral of Enforcement's own Division of Analytics and Surveillance about a gas marketing company that curtailed supply to customers to whom it had delivery obligations by citing *force majeure* and then sold gas to a different customer at a higher price, the report said.

Enforcement staff reviewed documents and took sworn testimony from employees and determined it lacked evidence to move forward. The firm's decision to sell gas to a different customer appeared to have been made during a small window of time when the marketing company believed its curtailments would be less substantial.

"Enforcement staff also did not find evidence that the marketing company actively sought out buyers to sell gas to at an elevated price," the report said. "To the contrary, the purchaser unilaterally reached out to the marketing company requesting gas."

DAS is regularly watching the electric and natural gas markets that FERC polices, with the report saying in fiscal 2023, its surveillance led to 567,000 screen trips in the electric markets, leading to 43 surveillance inquiries and six referrals for investigation. On the gas side, it had 24,000 screen trips on the year, leading to 27 surveillance inquiries and three referrals for investigation.

The division engaged in enhanced surveillance during "disruptive market events" related to December 2022's Winter Storm Elliott and a period of high energy prices in the West during the winter of 2022/23. It is continuing to analyze both market events and has already referred some matters related to last winter's weather events to investigative staff.

Overall, Enforcement opened 19 new investigations and closed nine pending probes without further action. Staff also negotiated 12 settlements that were approved by FERC for a total of $33.4 million: $11.7 million in civil penalties and $21.7 million in disgorgement.

Three other settlements resolved litigation in federal District Court for $4 million in disgorgement, one order to show cause for $4.4 million in civil penalties, and one U.S. Court of Appeals matter for a $10.75 million civil penalty.

Enforcement staff also completed nine audits of public utility, natural gas and oil companies that resulted in 68 findings of noncompliance and 332 recommendations for corrective action. They directed $33 million in refunds and other recoveries. ■

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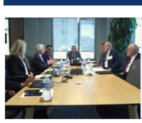

NERC 'Very Happy' With GridEx VII Participation — ERO Insider

NERC Expecting Packed 2024 for Standards Actions — ERO Insider

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FERC Optimistic About Energy Markets This Winter

But Concerns Persist About Grid's Vulnerabilities to Extreme Events

By Holden Mann

Higher-than-average temperatures in parts of the U.S. could reduce electricity and natural gas demand and help prevent energy shortfalls this winter, FERC staff said in the commission's *2023-2024 Winter Energy Market and Electric Reliability Assessment*, released Nov. 16.

However, the possibility of one or more prolonged cold weather events, along with drought and wildfires continuing through the season, means significant reliability risks remain, NERC staff told commissioners at FERC's open meeting.

The concern was stated most bluntly by Mark Lauby, NERC's chief engineer, who spoke after Commissioners Allison Clements and Mark Christie responded to FERC staff's presentation of the report. Although Clements noted the mild weather forecast and natural gas futures prices as "areas for optimism," and Christie said "hopefully we'll get through [winter] with some luck," Lauby professed to being "taken aback" by the commissioners' comments.

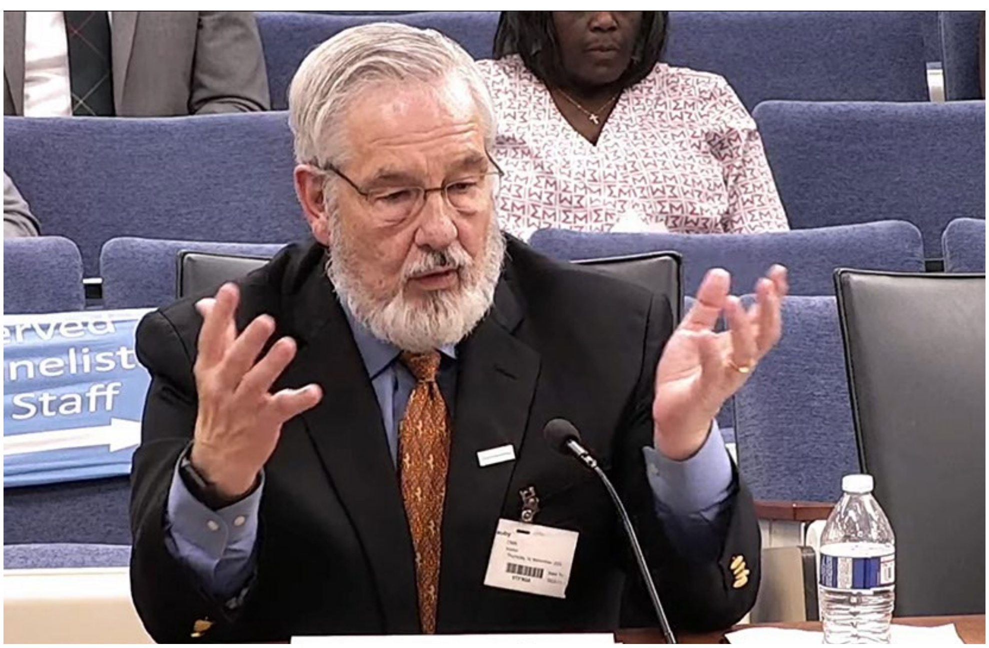
"I don't like to plan on hopes and dreams," Lauby said, noting NERC's own recently released *2023 Winter Reliability Assessment* warned that much of the North American electric grid faces elevated or high risk of energy shortfalls in December, January and February. (See *NERC: Grid Risks Widespread in Winter Months*.) "And even if, in fact, we have an average winter, that doesn't mean we won't have a cold spell during the winter. … That's the kind of stuff that keeps me up at night."

Mild Temperatures in North, West

FERC's assessment cited the National Oceanic and Atmospheric Administration's *seasonal temperature outlook*, which predicted that a strong El Niño effect in the Pacific Ocean will bring warm temperatures to the West Coast, leading to a strong likelihood of higher-than-normal temperatures across the northern U.S. The Southern states are equally likely to experience below-average temperatures as they are to experience above-average ones.

The likelihood of higher temperatures during the winter months — particularly in colder regions of the country — suggests less energy will be needed for heating and a lower likelihood of insufficient gas for both heating and electricity, FERC's report said. But the assessment also noted that NOAA's forecasts "do not include the probability of extreme cold weather events," which can affect energy supply and demand in unforeseen ways, and that "below-freezing temperatures can stress critical infrastructure … especially natural gas facilities."

Drought conditions are also expected to persist in the central U.S. through winter, potentially causing problems for hydropower plants in the north-central U.S. and lack of fresh water for thermal plants in the south-central areas. Similar conditions are predicted for the Pacific Northwest as well. In addition, the Canadian wildfire season — including several large existing fires — is now expected to continue into winter, which could affect regions in the U.S. with connections to Canada such as WECC, MISO and ISO-NE.



Mark Lauby, NERC | *FERC*

Drops Expected in Gas, Electricity Prices

FERC's report said natural gas prices are expected to be lower this winter than in previous years, despite rising demand, thanks to growing production and high natural gas storage levels. But while market fundamentals "indicate adequate availability of natural gas at the national level," local fuel availability may still be affected by "regional constraints."

According to the assessment, the predicted average natural gas demand is expected to reach 122.4 Bcfd, 4% over last winter and 7.2% more than the previous five-year average. Electricity generation constitutes about a quarter of this demand, at 32 Bcfd, with residential and commercial use making up the largest share, at 42.3 Bcfd. The biggest growth in demand is from net natural gas exports, which are projected to average 13 Bcfd this winter, up 21% from winter 2022-2023 and 62% from the previous five-year average.

Gas futures prices Nov. 1 were lower than the final settled futures prices for last year at all of the trading hubs cited in the report, and at several hubs, they were below the previous year's final settled prices as well. FERC's report attributed last winter's soaring prices to the impact of Winter Storm Elliott in late December.

Wholesale electricity prices are also projected to decline at most major pricing hubs compared to last winter, the assessment said, with the greatest difference seen in the West, where last year's record high gas prices contributed to higher electricity prices as well. Declines of at least $5/MWh are also expected in the Southeast, NYISO and PJM.

In SPP, prices are expected to increase from $37.81 on average last winter to $38.21 this winter. However, SPP is projected to have the lowest wholesale electricity prices on average of any region, the report said. ■

FERC/Federal News

Northeast States Detail Early Efforts on Interregional Tx Collaborative

By James Downing

States in the Northeast are working together to expand interregional transmission with a focus on coordinating the connection of offshore wind facilities to the grid, according to speakers on a Wednesday webinar hosted by Advanced Energy United.

Representatives from states working on the Northeast States Collaborative on Interregional Transmission spoke about the first months of their work since the effort was launched in June with a *letter* to the Department of Energy.

"We still are in early days of the collaborative," said Jason Marshall, deputy secretary of the Massachusetts Executive Office of Energy and Environmental Affairs. "But I think with as much expertise as we have in the room, focused in one place, we really do have a unique opportunity to chart a path forward toward greater interconnectivity."

While the collaborative has a focus on helping to connect offshore wind, Abe Silverman, director of the Center on Global Energy Policy's Non-Technical Barriers to the Clean Energy Transition initiative at Columbia University, said the benefits of transmission go well beyond that. Transmission has helped regions better manage recent reliability events such as last December's winter storm, he noted.

"This is about money at the end of the day for a lot of folks," Silverman said. "And so, as we think about building this coalition between various states — both states with really aggressive carbon policies and states with less interest in that — we really need to talk about the money piece of it, and transmission can be enormously cost saving as well."

The initial letter was signed by the six New England states, New York and New Jersey, which all have similar energy policies, but some of their neighbors are very different. Preethy Thangaraj, who advises New Jersey Gov. Phil Murphy (D) on energy policy, said that the states in PJM have very diverse energy policies — ranging from states like hers with strong net-zero goals, to West Virginia, where no such laws are on the books.

The best example for multistate transmission expansion is MISO's Multi-Value Projects, where every state got some kind of benefits, which helped connect a lot of wind power to the grid, said Silverman.

"But it was really looking at all of this sort of value stacking of benefits that transmission gives you," he added.

MISO is a very large RTO, but it is a single region, while the states in the planning effort stretch across three separate markets: ISO-NE, PJM and NYISO. That means they will need to go through interregional planning, which, despite Order 1000 being on the books for a decade, has not taken off.

Most interregional transmission lines have been backed by specific developers to ship renewables long distance, while those that have cleared the FERC planning processes have dealt with really "crisp issues," such as the loop flows around Lake Erie more than a decade ago that impacted reliability across several markets, said Silverman.

"The amount of true interregional planning, where you sort of look at the needs of one region and optimize it by building transmission to another region and look at their benefits and costs as well, is a relatively new concept, or at least it hasn't really been activated," said Silverman. "So, we talk about it a lot, but what we really need is for FERC, and to some extent the DOE, and I think the states, to come together and say: 'OK, you know, we've talked about this for a while, we now need to go ahead and actually do it.'"

The New England states especially have worked together on energy issues several times in the past, but really focusing on the transmission needed to help reliably and affordably to meet their clean energy goals is a new effort, said Bruce Ho, senior policy adviser for the Connecticut Department of Energy and Environment. And this time they need some help.

"Ensuring this effort is successful really does critically depend on the support and interactions we have with the federal government and particularly the Department of Energy," Ho said. "The transmission vision buildout we're thinking of crosses state borders; it's inherently federal." ■

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FERC/Federal News

EPSA Releases Policy Principles for Energy 'Expansion'

By James Downing

The Electric Power Supply Association (EPSA) has released a set of policy *principles* it hopes will inform legislators and regulators as they work to transition the grid to cleaner supplies and greater demand from electrification.

Many in the industry refer to the "energy transition," but EPSA CEO Todd Snitchler said in an interview Nov. 14 that the changes also include an "energy expansion," as electricity will be expected to take on new sources of demand including transportation and heating.

"Consumer adoption of new, electrified devices, heating and cooling systems, vehicles and industrial processes will drive further demand for electricity, and accurate wholesale pricing is needed that sends demand signals to customers to respond flexibly, economically and reliably," says EPSA's fifth principle.

The first principle is an endorsement of wholesale competition, the development of which enabled the independent power producer business model of EPSA's members. It says competitive wholesale markets are the most effective tool to achieve policy objectives by encouraging private capital deployment and innovation at the lowest costs, while shifting risks to investors — not consumers.

"Hopefully, this will encourage policymakers to think about these issues as they're making decisions about policy choices and resources and timelines," Snitchler said. "Because it's very easy to say you want a certain outcome; it's much more difficult to achieve it, and we hope these will help inform the 'achieving' part of those policy goals."

EPSA also says existing dispatchable resources will be needed to keep the grid reliable, even as they operate less often.

"As you see a greater penetration of renewable resources, you're going to continue to see a need for natural gas, because of the performance characteristics it has," Snitchler said. "It will be required when the sun isn't shining, or the wind isn't blowing, or you have other interruptions to non-dispatchable resources. Dispatchable resources that can respond quickly, power up and remain operational, like natural gas, are going to be profoundly important because they will be the difference between the lights staying on and us having a power outage."

Such power plants will run less often, but they will be important to maintaining reliability when they do run. Some of the market reforms will be required to ensure that plants that are vital for reliability but get fewer and fewer chances to earn money from the energy markets stay online.

"Market-based solutions, like a flexibility product, or a quick-ramping product, or something that will ensure that those resources are able to earn sufficient revenue to remain on the system, when they are needed, is going to be how we're going to have to think about it," Snitchler said.

Stepping back, system planning is based on parameters the industry came up with in the middle of the last century, but the grid has already changed significantly, with more on the way, so new planning methods will need to be developed.

In the past, EPSA had focused on trying to limit the impact of subsidies on wholesale power markets, but since the Inflation Reduction Act added billions of dollars more, those debates are in the rearview mirror, Snitchler said.

"We just have to figure out how to incorporate that into the policies that policymakers are going to subsequently have to implement in order to achieve their objectives," he added.

Many of those subsidies and the plans to decarbonize the electric industry rely on moving past natural gas eventually. While EPSA is technology agnostic, the resources that could replace gas-fired power plants are not ready to do so at scale, and it is uncertain when they will be.

"In the event that we can have the breakthroughs that will help us get to where small modular reactors can be the generation resource of the future, that would be great," Snitchler said. "The challenge is those technologies are talked about today like we are on the cusp of having it tomorrow, and it appears that we're farther away than that."

Just last week, NuScale Power had to cancel a proposed SMR in Utah, while other technologies like clean hydrogen have yet to be developed at the scale and price needed where they would start to replace natural gas. (See *Pioneering NuScale Small Modular Reactor Canceled*.)

Competitive markets are often where new technologies are first deployed once the economics make sense, but retiring natural gas plants too early will increase reliability risks, Snitchler said. Should there be a major crisis because of policy, it could easily lead to a backlash against the energy transition.

Polling consistently shows that consumers value reliability when it comes to the grid, Snitchler said.

"If we're moving too quickly, in any one direction, and that results in power outages, or crises that happen, public support will pretty quickly erode," he added. "So, I think that's something that we need to be mindful of as we go through this process, because it's not going to happen overnight, and we need to be thoughtful about how we get from here to the ultimate destination." ■

J-Power's Elwood Energy Center | *J-Power*

CAISO/West News

West-Wide Governance Pathway Group Digs into Its Work

Launch Committee Issues Mission Statement, Charter Guiding Effort for Single Western RTO

By Robert Mullin

The committee tasked with laying the groundwork for an independent Western RTO confronts a complex set of challenges on an ambitious timeline as it seeks to help CAISO outpace SPP in the contest to organize the region's electricity market.

Chief among the challenges: raising the money needed to finance the effort, which a group of Western state utility commissioners kicked off in July to boost the prospects of establishing a single RTO that pointedly includes California. The commissioners proposed the plan just as SPP's Market+ day-ahead market offering began making headway against CAISO's Extended Day-Ahead Market. (See *Regulators Propose New Independent Western RTO*.)

Members of the West-Wide Governance Pathway Initiative's (WWGPI) Launch Committee described the work ahead during a virtual stakeholder update Nov. 17, just days after the group released its *mission statement and charter*.

"The real mission is that we're looking to create an independent entity with independent governance that is capable of overseeing an expansive suite of West-wide wholesale electricity market activities and related functions," said Launch Committee Co-chair Pam Sporborg, director of transmission and market services at Portland General Electric.

Sporborg described the "core principles" — set out in the mission statement — guiding the committee's work:

- Establish an entity with the largest possible footprint in the West — including California — while maximizing consumer benefits.
- Ensure independent governance for all market operations.
- Preserve and build on existing CAISO market structures, including the Western Energy Imbalance Market (WEIM) and EDAM.
- Minimize duplication of costs for both the market operator and its participants.
- Create a structure flexible enough to support a full complement of RTO services while not requiring participating organizations to join a full RTO if they choose not to.

Funding Needed

In the month since it began meeting, the Launch Committee has created work groups to address specific "focus areas" to tackle issues in establishing the independent entity.

Organizational structure and funding will be the key focus of the Administrative Work Group, according to Jim Shetler, the group's co-chair. Shetler is general manager of the Balancing Authority of Northern California (BANC), which in August became the second organization to commit to joining CAISO's EDAM. (See *BANC Moving to Join CAISO's EDAM*.)

During the Nov. 17 meeting, Shetler said his group is evaluating whether the WWGPI should form a 501(c)(3) or "more of an informal association kind of structure." It also will determine whether the effort requires an initial "fiscal sponsor."

"We are stood up to do a lot of work and look at the governance structure alternatives for an independent oversight, but we don't have any dollars to do that right this minute, so we are looking at where we would get funding, both in the near term and long term," he said.

Near-term funding could come from "seed donations" by electric sector participants who've already expressed willingness to put up the money, Shetler said. The work group could also seek grants from foundations.

For the longer term, the group is working with Western state officials to file a grant request with the Department of Energy for federal funding, which likely would not materialize until the middle of 2024.

The group is examining the full scope of the WWGPI and the costs associated with administrative setup, outreach and communications, and legal analysis.

"I would anticipate we would have a better handle on what we think the dollars and cents would require … in the early to mid-December timeframe," Shetler said.

Laura Trolese, director of Western markets and strategy at The Energy Authority, asked where the funding would be found for the entity's foundational board of directors, which is slated to be seated in January.

"And maybe just a note that it could be problematic to have funding for that board that is either not or perceived not to be independent," Trolese added.

Shetler said his group recognizes the need for any funding to be "unbiased and not influential."

"Some of the federal dollars that might be coming our way [are] an option for that, but we have not had any detailed discussions yet on what that funding source may me, though we acknowledge and recognize we have to make sure that it's viewed as being independent," he said.

The West-Wide Governance Pathway Initiative is seeking to create an independent entity that includes the California grid. | © *RTO Insider LLC*

CAISO/West News

"We want the funding to really come from a broad and diverse set of entities," said the Launch Committee's other co-chair, Kathleen Staks, executive director of Western Freedom, an industry coalition that advocates for a single Western RTO.

Legal Questions

Examination of legal issues will fall to the Launch Committee's Priority Functions and Scope Work Group.

The group is charged with identifying "concrete options" for a market structure that integrates California, said the group's co-chair, Spencer Gray.

"Our goal is to define a range of solutions — or pathway options — that are related to tariff management for the markets and other services [and] what the governance structure looks like for a potential new regional entity," said Gray, executive director of the Northwest & Intermountain Power Producers Coalition (NIPPC).

The group will address legal questions associated with creating a regional entity, including what is possible under existing law and what are any associated litigation risks. It also will investigate the minimum changes needed in California law to alter CAISO's governance and operations to enable some of the options.

"And we want to be thorough in asking those questions without presenting a preferred solution yet; this can be viewed more like a solution set," Gray said.

While the single tariff covering CAISO and the WEIM gives both the ISO Board of Governors and the WEIM Governing Body voting rights, only the ISO board has the right to file rule changes with FERC, noted work group member Jeff Nelson, manager of market design and analysis at Southern California Edison.

"So we're starting with that place and sort of asking questions — what sort of things could move around? And what would require new tariffs?" Nelson said. The group also will explore what it would require for an independent entity to have "absolute rights" over market rules "without the ISO's current board having any say in those."

Gray said many stakeholders, including NIPPC, filed comments with the WWGPI asking for that kind of legal analysis "because there's been so much thinking about what are the options for greater autonomy for a regional entity in the context of the Western EIM and EDAM."

Communications, Outreach and Transparency

"Talking about markets to a general audience is quite challenging, as many of you know, so anyone who knows how to talk about this in an easily understandable way, we're always looking to improve," said the Northwest Energy Coalition's Ben Otto, co-chair of the Launch Committee's Communications and Outreach Work Group.

The group's focus will be threefold, Otto said, including supporting the committee's ability to communicate with WWGPI stakeholders; acting as a liaison between stakeholders and the work groups to "collect and share feedback"; and leading outreach with stakeholders, the media and others.

"Our goal here is just to be able to clearly communicate out to the public about what we're doing — our goals, our processes and our timelines," Otto said of the last point.

Launch Committee meetings currently are held in private. Allison Mace, manager of market policy and analysis at the Bonneville Power Administration, asked whether the committee plans to open future meetings to the public.

"We're continuing to have these types of public forums where we are able to get the input and share the updates on the Launch Committee, but … there will be other times where the Launch Committee will need to be able to discuss and deliberate about the feedback received in these meetings amongst ourselves," Sporborg said.

Staks said the committee is considering whether to hold additional topical public meetings, such as one to cover the legal analyses and scenarios outlined by Gray.

Shetler pointed out that the new charter states any decisions by the Launch Committee will be made in public session.

"We really are trying to make sure that this is a very transparent process," Staks said.

The Launch Committee will hold its next public update Dec. 15. ■

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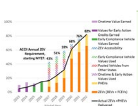

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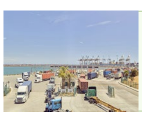

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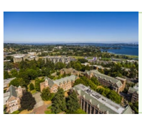

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Nevada Geothermal Auction Fetches $1M for BLM

Agency's Take Falls Short of 2022 Sale

By Elaine Goodman

As part of its efforts to lease land for renewable energy production, the Bureau of Land Management (BLM) auctioned leases for 33 geothermal parcels in Nevada on Nov. 14, fetching just over $1 million.

The sale offered 45 parcels totaling 134,866 acres in 12 counties. Bids were received for 33 parcels, covering 96,605 acres.

The leases went to eight bidders, according to *results* published by BLM. TLS Geothermics Corp. won leases for eight parcels. The French company also won leases for five Nevada parcels in a geothermal auction last year.

Zanskar Geothermal and Minerals won leases for six parcels. Zanskar's mission is to discover geothermal energy faster using big data, the Utah-based company's website states.

Ormat Technologies and Photosol US each won five leases. Norte Geothermal won leases for four parcels, and FLHN 1 LLC won three.

Rodatherm Energy Corp. and Baseload Power U.S. won leases for one parcel each.

BLM issues geothermal leases for 10 years. Following the auction, the winning bidders must submit site-specific proposals before energy development can begin.

Nov. 14's auction, which earned $1.025 million, was smaller in scope than BLM's Nevada geothermal lease auction last year. The bureau's competitive auction in August 2022 brought in $3.3 million for 66 Nevada geothermal parcels totaling 192,912 acres.

And those results are a far cry from a BLM auction in June that raised a record-breaking $105 million. That auction was for four parcels in the Amargosa Desert in southern Nevada for solar development. (See *BLM Holds Record-breaking Solar Auction in Nevada*.)

Still, Nov. 14's auction will help meet the Biden administration's goal of permitting 25 GW of solar, wind and geothermal production on public lands by 2025, BLM said in a release.

"Issuing geothermal leases is an important piece of the dynamic energy portfolio in Nevada," Justin Abernathy, BLM Nevada deputy state director of energy and minerals, said in a statement. "BLM carefully analyzed these parcels, and this successful lease sale is the initial phase to developing new, clean energy sources."

Ormat Technologies, which recently completed the North Valley geothermal power plant in Nevada, was the winning bidder for five Nevada geothermal parcels that the BLM auctioned this week. | *Ormat Technologies*

BLM has tentatively scheduled its next competitive geothermal lease sale for October 2024.

Nevada has 26 geothermal power plants in 17 locations, and the state's geothermal generation capacity of 827 MW is second only to California, according to the Nevada Division of Minerals.

Ormat has several geothermal power plants operating in Nevada. The Reno-based company submitted the highest per-acre bid in Nov. 14's auction of $130 for a 2,494-acre parcel in Mineral County.

Ormat's projects include a geothermal power plant in North Valley, Nev., whose completion was announced in May. The project included construction of a 58-mile transmission line in addition to the 25-MW power plant.

But another project Ormat is planning in Nevada has hit a roadblock: A group of plaintiffs filed a complaint in U.S. District Court in January challenging BLM's approval of Ormat's geothermal exploration project near the town of Gerlach.

The town is a gateway to the annual Burning Man festival, and plaintiffs in the case include the Burning Man Project, which runs the annual event, as well as the Summit Lake Paiute Tribe of Nevada and Friends of Nevada Wilderness.

The plaintiffs said BLM didn't consider in its environmental review the potential impacts to "inimitable" hot springs in the area. The defendants also failed to consider impacts of "the future but inevitable large-scale geothermal production project," the complaint said.

In addition to BLM, the Department of the Interior and Interior Secretary Deb Haaland are named as defendants. The federal defendants have denied the allegations. Parties in the case continue to file briefs. ■

ERCOT Cancels RFP for Additional Winter Capacity

By Tom Kleckner

ERCOT canceled its effort to procure additional generation capacity this winter Nov. 17, citing "limited response" from the market.

The Texas grid operator was seeking 3,000 MW of capacity with its request for proposal. Participants responded with 11.1 MW of "potentially eligible" capacity.

ERCOT CEO Pablo Vegas said Nov. 17 *during an interview* that it was "disappointing that there wasn't more available."

"One of the important outcomes of this RFP process was learning what the market response would be to this type of capacity request," he said in a *statement*. "We'll take these lessons and continue to work with the [Public Utility Commission of Texas] and the market to evaluate other types of demand response products that could contribute meaningfully to electric reliability in the future."

The ISO announced its intention in October to increase operating reserves this winter. It listed 20 mothballed and seasonally mothballed dispatchable resources that were eligible to respond to the RFP. Austin Energy and CPS Energy, owners of three of the four largest plants on the list, have said they would not bring their decommissioned units back to life. (See *ERCOT Searching for 3 GW of Winter Capacity*.)

Talen Energy notified ERCOT in August that it was planning to indefinitely suspend operations at the other large plant on the list, its 292-MW gas unit outside Corpus Christi. The grid operator evaluated offering a reliability-must-run contract for Barney Davis before Talen withdrew the suspension request on Oct. 27. (See "ERCOT Evaluating RMR Options," *Texas Public Utility Commission Briefs: Aug. 24, 2023*.)

Vegas said no generators offered their decommissioned units in response to the RFP, which presented three-month contracts that were to begin Dec. 1. The program's 11.1 MW came from entities offering to shed load during emergency conditions.

The awards would have been announced Thursday.

The ISO said it weighed factors such as the program's costs and the incremental additional complexity for its control room against the very small amount of capacity and the minimal reliability benefits in declining to proceed with the RFP.

"It will come as a surprise to no one that knows anything about power markets that ERCOT's Hail Mary attempt to procure zombie power plants failed," Stoic Energy CEO Doug Lewin said on X, formerly known as Twitter, putting in a plug for energy efficiency's benefits.

The RFP also drew pushback from the PUC's commissioners, who expressed concerns during an open meeting earlier this month over ERCOT's refusal to place a firm cap on the program's costs. Vegas told the commission staff had not yet set a budget for the RFP.

Commissioner Will McAdams *said* the RFP should be considered an interim or bridge solution under state rules. That would mean it would compete with funds under the $1 billion cap designated for the performance credit mechanism.

ERCOT said it "firmly believes" expanding demand response capabilities in the industrial, commercial and residential customer classes offers "tremendous potential." It said it will work with the PUC and stakeholders to explore incentives and product designs that may work better in the future.

The RFP was based on probabilistic analysis indicating ERCOT faced a 20% risk of entering energy emergency alert conditions this winter if the system was hit with another event similar to last December's Winter Storm Elliott. It said the 3,000 MW of additional capacity that could be called upon if needed was an "added layer of protection" during peak demand.

"The [RFP] was an extra layer of precaution to mitigate higher risk during extreme weather this winter," Vegas said. "ERCOT is not projecting emergency conditions this winter and expects to have adequate resources to meet demand." ■

The lights from Barney Davis twinkle across the Intercoastal Canal near Corpus Christi. | *© RTO Insider LLC*

NRG's Gutierrez Steps down as CEO, Director

Activist Investor Elliott Management Continues Focus on Capital Returns

By Tom Kleckner

Mauricio Gutierrez stepped down Friday as NRG Energy's CEO, an apparent victim of a push by activist investor Elliott Investment Management to reshape the organization's leadership.

NRG *said* Monday that Gutierrez had resigned as CEO and as a member of the board of directors. In a *filing* with the U.S. Securities and Exchange Commission, NRG said the resignation "was not the result of any disagreement with the company" or any matter concerning its operations, policies or practices.

However, Elliott, owner of more than 13% of NRG's shares, has been openly critical of the company's $5.2 billion acquisition of Vivint Smart Home earlier this year. Elliott has called the purchase "*the worst deal of the decade*" and called on the company to focus on returning capital to shareholders.

Interim CEO Lawrence Coben, the board's chair, said in NRG's press release that Vivint's integration is "well underway."

"As a differentiated company at the intersection of energy and smart home technology, NRG has clear upside-value creation opportunities," he said.

The board has begun seeking a permanent CEO and has retained a search firm to help.

"Today, NRG is in a position of strength. The board is confident in NRG's strategic direction," Coben said. "We extend our appreciation to Mauricio for his contributions in helping to build NRG's solid foundation as we prepare for the next generation of leadership."

Gutierrez joined NRG in 2004 and served in several leadership positions before being named CEO in December 2015.

The Houston-based company has a large presence in Texas. Reliant Energy, its electric retailer, owns about 40% of ERCOT's deregulated market, and NRG accounts for about 20% of the grid operator's fleet, noted Stoic Energy CEO Doug Lewin.

"This is big Texas energy news. [NRG has] been among the loudest voices for a capacity market, even though their power plants are often broken down when most needed," he *wrote* on X, the social media platform formerly known as Twitter.

Mauricio Gutierrez has stepped down as NRG Energy's CEO. | © *RTO Insider LLC*

NRG said it will also conduct a comprehensive review of its operations and cost structure to "further enhance capital return to shareholders" and to identify additional efficiency opportunities.

Elliott partner John Pike and portfolio manager Bobby Xu said the fund invested in NRG "because we believed that a renewed focus on best-in-class operations and returns-driven capital allocation would strengthen NRG and enable it to deliver significant upside for shareholders."

NRG also said Monday that, pursuant to a cooperation agreement with Elliott, it has added four new independent directors to the board:

- Marwan Fawaz, former executive adviser for Google and its parent company, Alphabet, and former CEO of Nest and Motorola Home;
- Kevin Howell, former Dynegy COO and former regional president for NRG Texas;
- Alex Pourbaix, CEO of Cenovus Energy; and
- Marcie Zlotnik, co-founder and COO of Texas retailer StarTex Power.

The four new directors were identified as part of NRG's board "refreshment process" in collaboration with Elliott, the company said. They increase the board's membership to 13, 12 of whom are independent. NRG said it expects to reduce the board's size to 11 members in the second half of 2024.

Howell and Pourbaix will join the board's CEO search committee, with fellow independent Directors Lisa Donohue, (the chair), Antonio Carrillo and Heather Cox. Incumbent Director Anne Schaumburg was appointed lead independent director. ■

ISO-NE News

New England Transmission Owners Issue Draft Asset Condition Forecast Database

By Jon Lamson

The New England Transmission Owners (NETOs) released a draft asset condition forecast database for the ISO-NE Planning Advisory Committee Nov. 15 and outlined updates to the asset condition project stakeholder review process.

As the New England grid ages, the region has faced rising costs associated with asset condition upgrades needed to replace old, degraded or defunct transmission infrastructure. On multiple occasions earlier this year, the New England States Committee on Electricity pressed the NETOs for reforms and greater transparency to the asset condition planning process. (See *States Press New England TOs on Asset Condition Projects*.)

The NETOs' *draft database* includes information on the issue targeted by the project and the proposed solution, along with the estimated project cost, in-service date, location and primary equipment owner. It includes projects that are under construction, proposed and in the planning stages. The total combined cost estimate for all projects in the draft database is about $4.5 billion.

Dave Burnham, representing the NETOs (Avangrid, Eversource, National Grid, Rhode Island Energy, Vermont Electric Power and Versant Power), said that the transmission owners plan to provide the forecast annually.

Burnham also *outlined* a series of updates to how asset condition projects are presented to the PAC, following feedback from stakeholders responding to the NETOs' proposed changes.

While the current standard requires that a project is presented to the PAC before construction begins, it has no defined stakeholder comment period.

Under the new proposal, for projects with an anticipated cost greater than $50 million, transmission owners would present potential solutions to the PAC at least six months prior to the start of major construction. Stakeholders would have a chance to give feedback, and three months later the transmission owner would present to the PAC responding to any stakeholder feedback and detailing the preferred solution.

For projects expected to cost less than $50 million, a presentation would be required three months prior to the start of construction detailing the preferred solution and soliciting stakeholder feedback.

Burnham said the proposal is aiming to "balance the need for increased notice and increased transparency but is also … something that we could commit to, given our own internal priorities and internal project development lifecycles."

If presentations to the PAC are required too far ahead of the beginning of construction, "sometimes we just don't have the detailed information that's necessary to really give stakeholders the full picture of a project," Burnham added. ■

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NECA Conference Focuses on Changes to ISO-NE Capacity Market

By Jon Lamson

WALTHAM, Mass. — Representatives from ISO-NE, Massachusetts and industry groups met on Nov. 13 to discuss major changes to the RTO's capacity market and the effects they could have on the region's clean energy transition at the Northeast Energy and Commerce Association's 2023 Power Markets Conference.

The potential changes include significant updates to ISO-NE's resource capacity accreditation (RCA) methodology, along with prompt and seasonal capacity market formats. A prompt auction format would reduce the time between the Forward Capacity Auction (FCA) and the capacity commitment period (CCP) from more than three years to just a few months, while a seasonal market would break the yearlong CCP into distinct seasons with separate auctions.

ISO-NE recently filed for a one-year delay of FCA 19, which applies to the 2028/29 CCP. The RTO is planning to use the delay to finalize its RCA updates and consider the different formats. (See *NEPOOL Votes to Delay FCA 19*.)

Chris Geissler of ISO-NE said the RCA updates are a key component of preparing for increasing amounts of variable resources and higher winter peak loads.

"The concerns are no longer really about just the summer peak, but about a much broader set of cases," Geissler said. "Because of that, we think it's important to try to align how we credit resources for their contributions with what we actually expect them to deliver when we need it."

Bruce Anderson of the New England Power Generators Association said the RCA changes are "an effort to create a capacity product that is substitutable across all resource types," and that updating the accreditation methodology "makes a lot of sense" at a broad level. Anderson added that the current methodology may improperly value certain resource types.

The specific effects of the RCA changes on different resource types are not yet clear. Preliminary *results* released in April indicated that the updates would increase accreditation values for wind and passive demand response (such as energy efficiency), while significantly reducing the values for energy storage, solar and active DR. However, ISO-NE has stressed that the RCA project is ongoing, and the results are subject to change.

From left: Jeff Bentz, NESCOE; Bruce Anderson, NEPGA; Chris Geissler, ISO-NE; Rosendo Garza (moderator), Day Pitney LLP | *© RTO Insider LLC*

Anderson noted that peaking resources like many oil generators have a greater reliance on the capacity revenues than resources with a greater reliance on energy markets.

"For different resource types, these changes are more critical for their viability," Anderson said. "Overall, the design creates a set of revenue opportunities where those resources can be viable."

Jeff Bentz of the New England States Committee on Electricity said ISO-NE and its stakeholders need to strike a difficult balance between states' requirements for renewable resources and the need to preserve reliability.

"I'm sure we're going to find out with the new modeling that some of this may not be as favorable to the type of resources that the states want to see grow," Bentz told the conference. He said that while the RCA changes might hurt the accreditation values of short-duration batteries, it could provide an incentive for longer-duration batteries with greater reliability benefits.

"If that incentive is out there, innovation grows and we get to longer-duration batteries for example, and they're rated highly in the new program, that will be good," Bentz said, noting there is a lot of work left to understand all the tradeoffs of the changes.

Prompt and Seasonal Implications

A seasonal market could be a way to differentiate between distinct reliability risks in the winter and summer periods, especially with the anticipated increase in winter risks, Geissler said, noting that ISO-NE has yet to make a recommendation on the potential move to prompt and seasonal formats.

Geissler added that a seasonal approach is a way to "be more granular in the capacity that we procure, so we're making sure we're meeting both the summer peak as well as extended winter cold spells."

Regarding a prompt market, Bentz said the current Forward Capacity Market has faced issues stemming from new resources that clear the market but do not reach operations on time or at all.

"Moving to a prompt market — from a consumer standpoint — you're going to get what you pay for on the day you pay for it," Bentz said.

Anderson said these "ghost projects" bring down the market price in subsequent auctions. He added that delayed projects force ISO-NE to decide to either grant the resource an extension or file with FERC to terminate the contract.

"Any resource coming into the market on a prompt basis, assuming it's going to be something in the order of say three, or even six months ahead of its delivery period, that's a resource that's built and ready to go," Anderson said.

In contrast, Anderson said moving to a prompt market could hurt price formation by failing to give enough advance notice that a resource is retiring compared to the current three-year forward market. This dynamic would limit the time available to address any reliability or resource adequacy issues created by the retirement and could lead to an increase in reliability-must-run agreements to keep resources online.

"You see the same issue of price formation in the market, it's dragging the price down for a resource that's being retained outside of the market, not pricing itself in the market," Anderson said. ■

ISO-NE Study Highlights the Importance of OSW, Nuclear, Stored Fuel

By Jon Lamson

ISO-NE *presented* the final stage of its Operational Impact of Extreme Weather Events study to stakeholders at the NEPOOL Reliability Committee (RC) on Nov. 14, shedding light on how changes to the 2032 resource mix could affect reliability in the region.

The analysis built upon findings for the winter of 2032, which were originally *presented* to the RC in *August*. The new results stemmed from additional tests — or "sensitivity analyses" — based on stakeholder requests, which included adjustments to the load profile, clean energy additions, and fossil fuel and nuclear retirements.

The sensitivity analyses assessed the 2032 grid under a worse-case scenario based on historical weather patterns from a 21-day stretch in the winter of 1961, which had the highest average system risk of all similar periods considered.

The analysis used the 2023 Capacity, Energy, Loads and Transmission (CELT) report's load forecast for 2032, with a resource mix built around the results of Forward Capacity Auction 17. It assumed the presence of the New England Clean Energy Connect transmission line, which is *under construction* in Maine but has faced extensive legal and political challenges.

The results "reveal a range of energy shortfall risks and highlight the increasing energy shortfall risk between 2027 and 2032, said Stephen George of ISO-NE. George qualified that the findings "are useful for highlighting directional changes in energy shortfall risk under various assumptions; [the] results should be considered in the context of the specific assumptions made and the attributes of the Jan 22, 1961, 21-day event."

The baseline case and the sensitivity analyses looked at shortfall with and without the Everett LNG import terminal in service. (See *FERC, NERC Leaders Voice Concern About Loss of Everett Marine Terminal*.) Counterintuitively, the modeling indicates that the presence of Everett marginally increases energy shortfall by enabling greater injections of LNG into the gas network and causing the region to run out of its LNG stockpile more quickly.

However, ISO-NE has cautioned that this aspect of the model should not be considered a perfect representation of future LNG stockpiling behavior.

The analysis found that replacing 1 GW of fossil resources with additional offshore wind capacity reduced the projected shortfall by 37 to 42% compared to the baseline scenario. In contrast, limiting the total offshore wind capacity to 1,600 MW — compared to the 5,600 MW assumed in the baseline scenario — increased the shortfall by 165 to 193%.

The offshore wind industry in New England has seen several major project cancellations over the past year, and industry experts have expressed their worry that this could push the in-service dates of the next wave of projects in the region into the 2030s. (See *Long-term Optimism Meets Short-term Concern at Offshore WINDPOWER 2023*.)

The study found that replacing a gigawatt of fossil fuel generation with onshore wind and utility-scale solar also improved reliability, but to a lesser degree. Onshore wind was associated with a 25% reduction in shortfall, while solar was associated with a 3 to 5% shortfall reduction. However, replacing the same amount of fossil fuel generation with two-hour-duration storage was associated with an 11 to 19% increase in shortfall.

The analyses modeled only two-hour-duration battery storage resources; ISO-NE received requests from stakeholders to look at longer durations but was limited by the study's time constraints.

"Future modeling enhancements will enable the incorporation of longer-duration storage," George said.

The baseline scenario did not include nuclear retirements, but the sensitivity analysis found that retirements would increase shortfall in all scenarios considered. Replacing all nuclear capacity with the same amount of renewable *qualified capacity* led to a 50 to 76% shortfall increase. George noted that retiring nuclear resources without corresponding renewable replacements would also significantly increase the region's reliance on oil and LNG.

Regarding fossil fuel resources, the study found residual fuel oil (RFO) resources to be especially helpful to maintaining grid reliability. Replacing all RFO resources with the same amount of renewable qualified capacity led to a 19 to 36% increase in shortfall.

"Energy from resources that burn stored fuels will continue to be important in terms of minimizing energy shortfall as the region transitions to higher penetrations of renewable resources," George said.

The study found that the retirement of 1.5 GW of gas-only generators had minimal effects on the projected shortfall because of the limited amount of natural gas available during the study period. Replacing these retiring resources with an equal amount of renewable nameplate capacity decreased shortfall by 24%.

Increasing the level of electricity imports also made a significant dent in the projected shortfall; a 50% increase in imports coupled with the elimination of the cap on maximum transfer capability reduced shortfall by 66%. Demand response also boosted reliability; an added gigawatt of active demand response capacity cut shortfall by 38 to 39%.

Finally, changes to the overall load profile had a significant effect on the shortfall. Increasing the load by 10% led to a 156 to 192% increase in shortfall, while decreasing load by 10% reduced shortfall by 84 to 87%. A 20% increase in behind-the-meter solar reduced shortfall by 7 to 10%.

ISO-NE hopes to release a final report covering the results from all phases of the study in late November or early December. Following the final report, the RTO plans to use the results to begin work on a "Regional Energy Shortfall Threshold," which will establish "the region's acceptable level of reliability risk." ■

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MISO News

MISO Says Overloads and Congestion Loom Without 2nd Long-range Tx Portfolio

By Amanda Durish Cook

MISO Executive Director of Transmission Planning Laura Rauch | *© RTO Insider LLC*

CARMEL, Ind. — After completing its initial economic and reliability analysis, *MISO* has found that numerous overloads and congestion await its system if it doesn't recommend a second long-range transmission plan (LRTP) portfolio.

"Keep in mind this is the start of the analysis. There's much more work to do to translate these studies into transmission lines. So, expect to hear overloads today, not transmission projects," Executive Director of Transmission Planning Laura Rauch told a Nov. 15 Planning Advisory Committee meeting.

That said, MISO *found* "significant" overloads and congestion on the system when it applies its envisioned 2042 resource mix in studies. Rauch said she expected the study results to show problems in the system.

Rauch said the second LRTP portfolio likely will shape up to be a "more complex solution" than the first, $10 billion LRTP portfolio. She said MISO's analysis by 2042 found lines reach stability limits instead of just thermal limits and foresees a greater need for reactive power.

Rauch said MISO may have an idea of some projects by early spring.

"I would say at this point, all solutions are still on the table," Rauch said of project sizes and voltages.

Rauch said MISO's West Region — Minnesota, Iowa, Wisconsin, North Dakota and portions of South Dakota, Montana and Michigan's Upper Peninsula — showed a need for higher-voltage transmission facilities to "support large power transfers and enable generation resources from remote areas to be delivered to load centers."

By 2042, MISO found 20% of the facilities in the West Region will be overloaded, with annual generation curtailments exceeding 15%.

On the other hand, MISO said its Central Region — most of Illinois and Indiana and portions of Kentucky and Missouri — will be instrumental to supporting system transfers. It said about 10% of the Central Region's facilities will be overloaded by 2042 without significant transmission expansion.

Rauch also said she expects MISO will have "additional challenges to solve" in the Central Region based on anticipated weather patterns and expanded transfer needs.

Finally, MISO's East Region —most of Michigan's Lower Peninsula — will need increased import and export capabilities by 2042. By then, MISO said about 10% of the East Region's facilities will be overloaded, with annual curtailments surpassing 15%.

Rauch said the overloads and binding constraint hours uncovered in MISO's initial studies will form the foundation of its list of transmission needs for the second LRTP portfolio.

"We may not solve all of them, but all of them will be considered," Rauch said.

Rauch also said MISO has been sharing the results of its LRTP analyses with the Independent Market Monitor, who has voiced concerns with the future energy mix MISO predicts by 2042. (See *MISO Promises Analyses on Long-range Tx; Stakeholders Divided on IMM Involvement*.)

The second LRTP cycle again zeroes in on MISO Midwest; the third portfolio will pay attention to MISO South needs, and the fourth will address power exchange limits between the Midwest and South regions. MISO has said while the first, $10 billion portfolio is an "important start, further work is needed to ensure reliability."

Meanwhile, the Organization of MISO States again has hired RLC Engineering to independently assess future projects in the second LRTP portfolio. For the first portfolio, RLC arrived at a 1.4:1 benefit-to-cost ratio for projects, smaller than MISO's overall projection of 2.6:1.

MISO will hold an LRTP workshop Dec. 1 to dedicate more discussion to its initial findings.

"We're just getting started and looking forward to the journey," Rauch said. ■

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DOE Offers $3.5B for Domestic Battery Manufacturing, $444M for Carbon Storage

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MISO News

MISO, SPP Ditch 90/10 JTIQ Allocation After $465M DOE Grant

By Amanda Durish Cook

CARMEL, Ind. — Weeks after the nearly $2 billion Joint Targeted Interconnection Queue (JTIQ) transmission portfolio was awarded a $465 million Department of Energy grant, MISO and SPP are switching their proposed cost allocation for the projects.

Now, all costs of the JTIQ portfolio should be assigned to interconnection customers, MISO and SPP have agreed. The new cost allocation will replace the RTOs' previously proposed 90% assignment to interconnecting generators with the remaining 10% to load.

The RTOs have further said all operations and maintenance costs on the projects will be borne by the constructing RTO's load.

Last month, DOE announced the JTIQ portfolio will receive $464.5 million from the department's Grid Resilience and Innovation Partnership program. (See *DOE Announces $3.46B for Grid Resilience, Improvement Projects*.)

MISO Director of Resource Utilization Andy Witmeier said MISO, SPP and states are in the middle of negotiations with DOE before they can receive the money.

Speaking at a Nov. 15 Planning Advisory Committee meeting, Witmeier said the grant will help get the JTIQ portfolio online "to the benefit of generators waiting to interconnect." And he said a more simplified cost allocation likely will help move the projects across the finish line, even though MISO and SPP had settled on the 90/10 allocation almost a year ago.

345-kV lines in the JTIQ portfolio | *MISO and SPP*

"This is what MISO and SPP believe will have the most success in getting approved," he said.

Witmeier characterized the change in direction on cost allocation as a "small pivot." He said MISO always would have used the grant money to apply for the load's share of project costs first, and the $464 million grant more than takes care of the tab load would have picked up under the original cost allocation proposal.

Witmeier said MISO and SPP concluded DOE's funding can address rate complexities the 10% allocation to load will introduce in how costs will be spread across load and how operations and maintenance costs will be handled. He said using a 100% allocation ensures entitlements are assigned to the constructing region and reduces risk that load in one RTO is supplementing transmission in the other in the unlikely case not enough generation shows up to fund the lines.

Witmeier said the 100% method is a "much simpler rate design, if you don't have load in that calculation."

He also said the 100% allocation to generators matches SPP's existing interconnection upgrades allocation and allows MISO and SPP to approach FERC with a "consistent approach."

"The 100% is a small shift for MISO, but the 90/10 was a big shift for SPP," he said.

In MISO's individual queue process, interconnection customers bear 100% of interconnection costs except when network upgrades are 345 kV or higher, when the 90% to interconnection customers, 10% to load allocation kicks in.

In an email to *RTO Insider*, SPP confirmed the new rate design will be a better fit with its current cost allocation for generator interconnection projects.

Xcel Energy's Carolyn Wetterlin said her utility agrees with the change. She said a 100% allocation will result in a "cleaner filing" to FERC and less costs borne by ratepayers in MISO and SPP.

However, the Coalition of Midwest Power Producers' Travis Stewart said the change is significant and interconnection customers have concerns.

National Grid Renewables' Maggie Kristian said some generation developers weren't comfortable with load's small share in the allocation to begin with. She said it's disappointing to see even that small amount reduced to nothing.

Witmeier said the 100% cost allocation to projects will apply only to the first JTIQ portfolio. He said MISO and SPP will have to "go back to the drawing board" for future JTIQ portfolios and devise a new cost allocation. The RTOs hope FERC gives its blessing for JTIQ planning to become a cyclical process and replace their affected system study process.

Witmeier also said there are always lingering concerns about free riders in transmission cost allocation. He said while interconnection customers might be upset to completely cover the JTIQ bill, load is probably unhappy taking on 100% of MISO's long-range transmission plan costs.

"We've been having this discussion in the MISO community for the past 15-20 years, what is the appropriate formula for generation and load," Witmeier said.

He said while MISO will hear written concerns on the allocation change through Dec. 6, it's unlikely to influence changes to MISO and SPP's direction.

The RTOs also found a change in adjusted production cost benefits of the JTIQ portfolio between MISO and SPP since it first conducted a benefits analysis in 2021. Now MISO can expect to see a $76.5 million benefit, while SPP will experience $99.3 million in benefits over 20 years. The RTOs originally found a $55.7 benefit for MISO and a $132.9 benefit for SPP over the first 10 years the projects are in service.

As far as how the DOE grant will be split between MISO and SPP, that's unknown, Witmeier said. He said that depends on how many projects apiece from the MISO or SPP clear their respective interconnection queues. ■

MISO Decides Battery Storage Can Use As-available Tx Service

By Amanda Durish Cook

CARMEL, Ind. — Battery storage that charges from the grid should be able to use non-firm transmission service, MISO has decided.

MISO is discarding its previous requirement that battery storage needs to secure yearly, firm point-to-point transmission service before it can charge from the grid. (See *MISO Agrees to Dial Back Tx Service Requirements for Energy Storage*.)

Manager of Resource Utilization Kyle Trotter debuted draft business practice manual language adopting the changes at a Nov. 15 Planning Advisory Committee meeting.

Staff in October said battery storage should be treated like any other intermittent load in MISO and should be able to use as-available transmission service. That means storage owners will be free to use the less expensive non-firm, point-to-point transmission service or MISO's Network Integrated Transmission Service for any length of time.

Trotter said MISO hopefully will be able to incorporate the change formally by the first quarter of 2024. He said if the Planning Advisory Committee is receptive, MISO will test out the changes with the Market Subcommittee in January.

Changes to MISO's business practice manuals require only a review from MISO's legal team to be implemented. They are not filed with FERC. ■

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MISO News

MISO to Focus on LRTP, Congestion for MTEP 24

By Amanda Durish Cook

Jeremiah Doner, MISO | *© RTO Insider LLC*

CARMEL, Ind. — MISO last week said the bulk of its 2024 Transmission Expansion Plan (MTEP 24) will look much the same as last year's, with an emphasis on long-range transmission planning and near-term congestion studies in addition to its usual round of annual studies.

MISO took stakeholder suggestions in early fall on what additional planning studies it may undertake as part of MTEP 24. However, planning staff warned that MISO is limited next year in what it can accomplish because it's performing extensive analysis under its ongoing long-range transmission plan.

The Municipals, Co-ops and Transmission-Dependent Utilities Sector requested MISO perform a study centered around the potential effects of widespread energy storage additions and analyze grid-enhancing technologies' ability to provide flow control.

MISO said it will consider energy storage and grid-enhancing technologies over the course of its regular MTEP studies, but not under a dedicated analysis. The RTO said it's always open to considering non-transmission alternatives to projects.

"We don't see the need for a standalone study. We see where the annual MTEP process can address that," MISO's Jeremiah Doner said at a Nov. 15 Planning Advisory Committee meeting.

However, MISO said a continuation of this year's near-term congestion study is on the table as part of MTEP 24. (See MISO *May Use Inaugural Near-term Congestion Study to Plan Smaller Tx Upgrades*.)

Doner said MISO hasn't settled on a scope for the near-term congestion study.

"It's too early to say what that study is going to produce," he said.

MISO previously said the study again will be exploratory and likely won't result in project recommendations.

Some members of MISO's Environmental Sector have expressed disappointment that MISO will take another year of hypothetical testing before it recommends small projects that alleviate congestion.

MISO said it needs more time to refine its transmission planning model to solve congestion on a five-year horizon instead of in the long run. Planners said they are open to tweaking the scope and study assumptions based on stakeholder requests.

Some stakeholders have said MISO already has a template for studying regional congestion and cost allocation with its Targeted Market Efficiency Projects with PJM. But MISO said the MTEP interregional process is materially different.

MISO planners have said that if any market participant is concerned about congestion in the near term, they can pursue a market participant-funded transmission project. ■

MISO News

MISO's More Stringent Interconnection Queue Rules Go Before FERC

By Amanda Durish Cook

Andy Witmeier, MISO | *© RTO Insider LLC*

CARMEL, Ind. — MISO this month put its package of changes meant to downsize its crammed interconnection queue before FERC and plans to conduct a survey of its interconnection customers to gauge how many projects it should expect.

MISO split its package of stiffer interconnection rules into two filings at FERC. One tackles the increases to milestone payments and tighter land requirements, while the other proposes an annual megawatt cap on project submissions according to a feasibility formula (*ER24-340* and *ER24-341*). MISO has determined there's only so many potential generation projects it can simultaneously consider and still achieve accurate interconnection studies. (See *MISO Relaxes Proposal on Stricter Queue Ruleset*.)

To estimate how many submissions it might be facing when it finally opens its project application window in early 2024, MISO will conduct a survey of its interconnection customers on the number, size and type of projects they plan to submit.

During a Nov. 15 Planning Advisory Committee meeting, Director of Resource Utilization Andy Witmeier said MISO won't publicly share the volume of projects it expects based off survey results. He said the idea is for MISO to have an idea internally of how many projects to prepare for.

Witmeier said MISO will publish a megawatt cap before it opens the 2023 cycle. He said even though applications have been pushed into the first quarter of 2024, MISO still will administer a 2024 queue cycle later in the year.

MISO delayed opening a queue application window this year because it wants the new queue rules in place first to deter another unmanageably large number of gigawatts from joining the queue.

Witmeier said the exact launch of the 2023 application window is contingent on FERC's decisions on MISO's pair of filings. MISO asked for a Jan. 22 FERC effective date. Stakeholders can comment on the filings at FERC through Dec. 4.

MISO has proposed that its megawatt cap be based on its ability to develop a reasonable dispatch based on the existing system with existing interconnection requests and the regional and subregional peak load in the study model.

A few weeks before it put its filings to FERC, MISO said a yearly megawatt cap on interconnection requests would be beneficial, incentivizing interconnection customers to submit their project request as soon as possible, instead of at deadline when the application window closes. MISO said that in turn would produce an earlier evaluation of the application, better coordination with transmission owners on selected points of interconnection and a public posting of accepted applications, allowing other developers to make more informed decisions regarding their own projects.

Witmeier said the package of stepped-up requirements would yield higher-quality projects, while the cap would allow a more viable study process for MISO.

"We do believe we need a backstop to limit the size of the queue study," Witmeier said at an Oct. 11 Planning Advisory Committee meeting. He said scaled-back study cycles would result in more realistic modeling of potential system overloads and voltage support assumptions.

"I realize the package is not what everyone wants," Witmeier said. But he said he views the more strict rules as becoming a "permanent fixture" of MISO's interconnection queue. ■

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White House Releases Climate Assessment, $6B for Resilience Projects

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NYISO Braces for the Coming Winter

OC Elects New Vice Chair, Approves Winter Operations Report

By John Norris

Winter Operating Study Report

NYISO's Operating Committee on Nov. 16 approved the winter 2023/24 operating study *report*, which found New York's bulk power system can operate reliably this winter based on calculated transfer capabilities.

The report by the ISO's Operating Studies Task Force estimates internal and external thermal transfer capabilities for the upcoming winter season based on forecast load and dispatch assumptions, as well as any generation or transmission changes since last year. The external analysis covers NYISO's adjacent balance areas of ISO-NE, PJM and Ontario's IESO.

The task force *reported* an increase in internal thermal transfer limits for the Total East (1,525 MW) and Central East (1,825 MW) interfaces due to Segments A and B of the Alternating Current transmission *project*, which was designed to increase the deliveries of renewable power to downstate New York.

Changes to external transfer limits also were seen. The ISO-NE-to-NYISO interface saw a decrease of 225 MW due to the reactivation of the Sprainbrook-East Garden City (Y49) 345-kV line. Meanwhile, the NYISO-to-PJM interface increased by 250 MW due to changes in PJM's dispatch assumptions and the PJM-to-NYISO interface increased by 75 MW due to the redistribution of flows from the Segment A and B project.

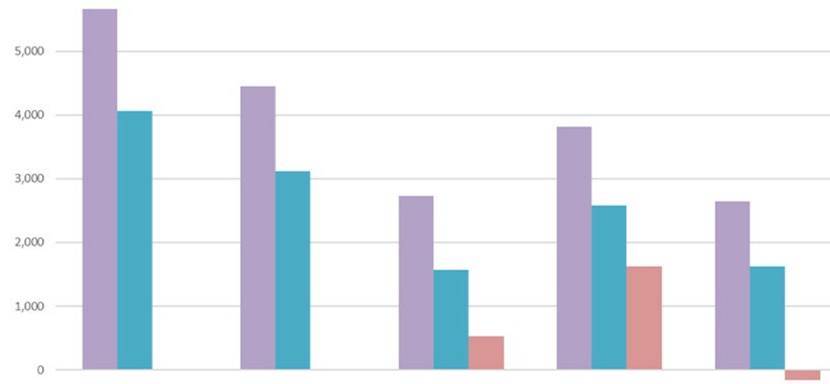
NYISO reported that 639 MW of fossil-fuel based generating capacity was deactivated and that 336 MW of renewable generation was added since last year's study. The *appendices* are posted online.

Winter Capacity Assessment

Aaron Markham, NYISO vice president of operations, *informed* the OC that while NYISO expects sufficient capacity for 50/50 peak forecast winter conditions, there is a risk of shortfalls during extreme weather events if non-firm fuel resources become unavailable.

The assessment projects winter generation capacity of 39,668 MW, approximately 750 MW lower than last year's assessment, due primarily to the retirement of peaker units.

"Over the last approximately five years, we've seen about a 2,400-MW reduction in the margin as a result of retirements," Markham said. "Continued reductions in winter capacity, disruptions in fuel supply or other concerns might result in operational challenges, especially during extreme cold weather events."



	19-20	20-21	21-22	22-23	23-24
50/50 - Only Firm Fuel	5,668	4,447	2,730	3,812	2,641
90/10 - Only Firm Fuel	4,067	3,118	1,566	2,583	1,625
99/1 - Only Firm Fuel			525	1,619	-161

Projected capacity margins for normal and extreme weather conditions in New York | *NYISO*

Projected winter capacity margins for normal and extreme weather conditions with only firm fuel resources available:

- 2,641-MW surplus capacity margin for 50-50 peak forecast conditions
- -161-MW deficit capacity margin for 99-1 peak forecast conditions

Projected winter capacity margins for normal and extreme weather conditions with non-firm fuel available:

- 9,135-MW capacity margin for 50-50 peak forecast conditions
- 6,333-MW capacity margin for 99-1 peak forecast conditions

Projected firm fuel generation potentially unavailable at high load or temperature conditions (*NYISO 2023 Gold Book, Table I-20*):

- 114 MW lost for 90-10 daily average temperature (5 F)
- 707 MW lost for 99-1 daily average temperature (-2 F)
- 707 MW lost for 90-10 daily minimum temperature (0 F)
- 3,441 MW Lost for 99-1 daily minimum temperature (-8 F)

Markham said NYISO will continue monitoring winter conditions and communicate any emergencies to stakeholders. The ISO is continuing to review the 11 recommendations from the FERC and NERC joint inquiry into the electric outages caused by Winter Storm Elliott. (See *Déjà Vu as FERC, NERC Issue Recommendations over Holiday Outages*.)

Matt Cinadr, a power systems operations specialist with The E Cubed Co., revisited a stakeholder concern regarding the treatment of special case resources by NYISO, saying the assessment's findings highlight that these resources should not be overlooked. (See *Providers See 'Mixed Signals' on Demand Response in NYISO*.) "I don't think anything should be done to push SCRs further out of the market," he said, "there is value in the [802 MW of SCRs] being shown in your assessment."

OC Election

The OC elected James Kane, senior energy market adviser with the New York Power Authority, as the committee's new vice chair. Kane *co-chaired* the Electric System Planning Working Group in 2021.

October Operations

Markham also *told* the OC that October's load peaked at 21,735 MW on Oct. 4, recorded its minimum load of 11,890 MW on Oct. 8 and added 73 MW of behind-the-meter solar since the previous month.

He added that the Oct. 14 annual solar eclipse had a minor impact on BTM production, affecting only 100 MW, significantly less than the anticipated 700 MW. (See "Eclipse Preparation," *NYISO Business Issues Committee Briefs: Sept. 14, 2023*.) ■

NYISO News

NYISO Stakeholders Advance Rules on Ambient Ratings, Internal Controllable Lines

Stakeholders Elect New BIC Vice Chair

By John Norris

FERC Order 881

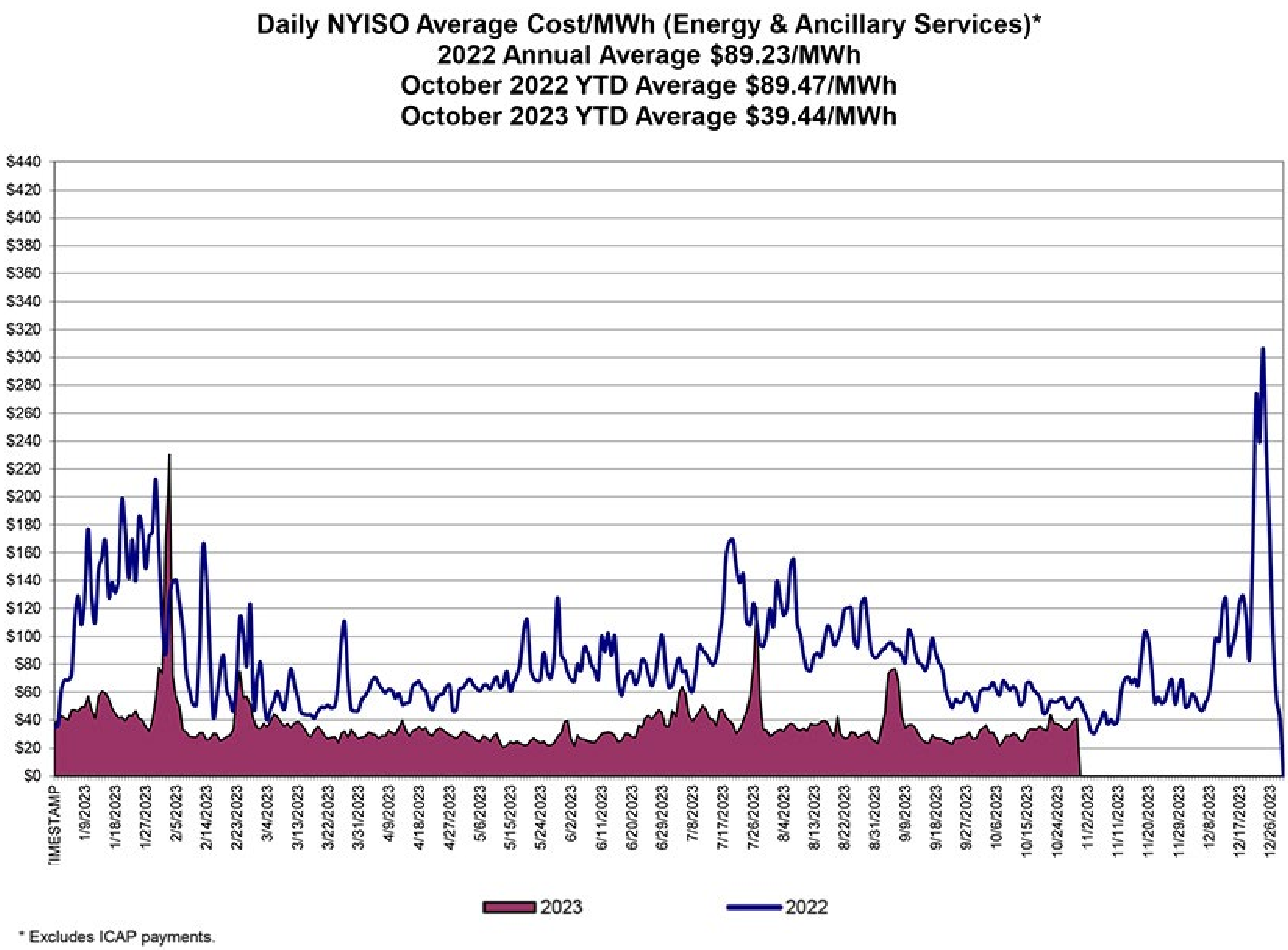
RENSSELAER, N.Y. — NYISO's Business Issues Committee on Wednesday *approved tariff revisions* to align day-ahead market (DAM) congestion settlement procedures with ambient-adjusted ratings (AARs).

FERC Order 881, issued in December 2021, mandated transmission providers evaluate their transmission capacity based on real-time environmental conditions, such as air temperature, wind speed and solar radiation (*RM20-16*). The order requires transmission providers to use AARs for short-term transmission requests — 10 days or less — for all lines impacted by air temperature. Seasonal ratings will be required for long-term service. (See *FERC Orders End to Static Tx Line Ratings*.)

NYISO's proposed *revisions* aim to resolve inconsistencies between AAR rating limits used in the DAM and those assumed in transmission congestion contract (TCC) auctions.

This included changes to calculations of the congestion rent impacts of uprates and derates and the creation of a new category of qualifying events resulting from differences in the DAM ratings required by Order 881 and those assumed in TCC auctions.

FERC partially rejected NYISO's initial July 2022 compliance filing, saying that some of the ISO's revisions fell outside Order 881's scope, certain terms were inadequately defined and the ISO was non-compliant with the timeline requirements of the order. (See *FERC Approves*



Daily NYISO average cost/MWh for 2022 and 2023 | *NYISO*

NYISO News

Batch of Line Ratings Compliance Filings.) NYISO is awaiting a decision on its second compliance filing, submitted in June 2023.

NYISO's ability to adjust its transmission line ratings in real time has become increasingly important to maintaining grid stability and efficiency, especially as the grid integrates more intermittent energy sources and climate change leads to more variable weather patterns.

The proposed changes now move to the Nov. 29 Management Committee for final approval. The ISO plans to implement the changes alongside its compliance proposals already accepted by FERC.

Internal Controllable Lines

The BIC also *voted* Nov. 15 to recommend the MC's approval of energy market, capacity market and market mitigation *rules* for new "internal controllable lines" (ICLs).

Clean Path New York (CPNY), a 175-mile, 1,300-MW HVDC line, will be the *first* ICL in the New York control area. CPNY, which was selected under the New York State Energy Research and Development Authority's *Tier 4* renewable energy certificates program, will deliver renewable power generated upstate into New York City.

The ISO's *revisions* will optimize ICL flows based on economic dispatch to serve loads at the least as-bid cost. Bilateral energy market transactions will not be permitted to source to or sink from an ICL.

The lines will be eligible for day-ahead bid production cost guarantee (BPCG) payments and for real-time BPCGs only if they are dispatched out-of-merit for reliability. They also will be eligible for day-ahead margin assurance payments when scheduled out-of-merit or derated for system security or to permit the ISO to produce additional operating reserves.

ICL bids will include an operating range and up to an 11-step dollar/MWh curve based on CPNY's willingness to be paid or to pay to transmit energy between its two terminals. They will be limited to a maximum bid of $1,000/MWh and a minimum bid of -$1,000/MWh.

Both day-ahead and real-time settlements will be based on the price differentials between the injection and withdrawal buses, and line losses.

The ISO said it is proposing a flexible capacity market design without tying supply to specific generators. An ICL must hold unforced capacity delivery rights to be a capacity supplier; it would transmit pooled capacity, sourcing in the NYCA and sinking in a locality.

Because HVDC lines can ramp up and down as fast as 1,000 MW per second — versus the 10-20 MW per minute averaged by a typical 1,000-MW generator — ICLs' ramp rates may be subject to limits to protect system stability.

No new market mitigation measures will be required for ICL's functionality but the ISO will develop a new conduct test for uneconomic production.

Mark Younger, president of Hudson Energy Economics, asked about NYISO's proposal to set ICL deviation charges — fees assessed to market participants for differences between their scheduled and actual energy generation or consumption — at 1.5% of the ICL's upper operating limit.

Michael Swider, senior market design specialist at NYISO, explained that the deviation tolerance was reduced from 3% because the operations team determined the lower threshold to be more appropriate.

Assuming approval by the MC, NYISO plans to file its revisions with FERC in early 2024.

BIC Election

The BIC elected Timothy Lundin, transmission regulatory policy manager for LS Power Grid NY, as the committee's new vice chair.

Lundin currently chairs the Electric System Planning Working Group's but will leave that position at year's end.

October Market Operations

NYISO Senior Principal Economist Nicole Bouchez *presented* the October market operations report, noting significant declines in natural gas and distillate prices and average monthly energy costs.

October's average energy cost was 56% lower than the previous year, falling from $89.47/MWh to $39.44/MWh. Natural gas and distillate prices saw year-over-year reductions of 72.2% and 27.2%, respectively. The month's LBMP also decreased to $28.10/MWh, lower than September's $36.92/MWh and last October's $53.11/MWh.

Bouchez *mentioned* the delayed development of an operating protocol for the Long Mountain phase angle regulator (PAR) installation, also known as the Dover PAR, due to ongoing court challenges (*2023-50796*). The timeline to complete an agreement for this 345-kV intertie between NYISO and ISO-NE remains uncertain.

Project Prioritization Proposal

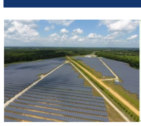
At the Nov. 15 Budget & Priorities Working Group meeting, Kevin Lang, partner at Couch White representing the City of New York and Multiple Intervenors, *proposed* major changes to NYISO's project prioritization process that seek to shorten the process, improve stakeholder coordination and enhance overall efficiency.

Lang suggested shifting project prioritization to later in the year to allow for more accurate assessments of project costs and resource availability and facilitate a smooth transition into the subsequent year's work. He acknowledged this could increase NYISO staff workloads but said the benefits would outweigh the extra effort

The proposal was well received, with both Younger and Anthony Abate, lead energy market advisor for the New York Power Authority, commending Couch White for striving to improve these processes. They agreed that more information would enable better decision-making.

Lang encouraged stakeholders to send comments or suggestions to *klang@couchwhite.com.* He said he plans to present an updated proposal that incorporates submitted feedback in January 2024. ■

National/Federal news from our other channels



Treasury Department NOPR Seeks to Clarify IRA's ITC Rules

NetZero Insider

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

NYISO News

NYISO to Keep Gas Peakers Online to Solve NYC Reliability Need

Gowanus 2 & 3 and Narrows 1 & 2 Gas Plants to Operate Past 2025

By John Norris

Gowanus barge-mounted natural gas generating station in Brooklyn, New York | *Astoria Generating Company*

NYISO *announced* Nov. 20 it will keep two natural gas peaker plants in Brooklyn operational beyond their state-mandated retirement to address a generation shortfall in New York City.

The ISO's Nov. 20 *Short-Term Reliability Process Report* said the Gowanus 2 & 3 and Narrows 1 & 2 barge-mounted power plants will remain online to help plug a 446-MW reliability deficit.

The deficit was identified in NYISO's second quarter *Short Term Assessment of Reliability,* which said the city would be short for up to nine hours on the peak day in 2025 during expected weather conditions, assuming forecasted economic growth and policy-driven increases in demand. (See *NYC to Fall 446 MW Short for 2025, NYISO Reports*.)

The two facilities, owned by Astoria Generating Co., collectively can generate 564.9 MW and contribute 508 MW toward New York City's transmission security margin.

The Gowanus *facility* has been operational since 1971 and compromises 32 simple-cycle combustion turbines, each with a nameplate value of 20 MW. The Narrows *facility* has been running 32 similar units since 1972, but with a nameplate value of 22 MW.

NYISO's decision highlights the challenges New York faces in balancing reliability with environmental regulations and increasing energy demands under electrification.

NYISO Chief Operating Officer Emilie Nelson said the ISO is committed to a reliable transition to emissions-free resources and is aware of how fossil fuel plants — a source of ozone-contributing pollutants — affect surrounding communities. "This means running these units only when conditions require, and closing them when no longer necessary for reliability," she said.

The ISO's report says Gowanus and Narrows help New York City's bulk power transmission system during unexpected facility outages or during extreme weather conditions like a heat wave when other power producers may become unavailable.

The units were set to retire May 1, 2025, to comply with the Department of Environmental Conservation's 2019 Peaker Rule, which imposes nitrogen oxide emissions limits on fossil fuel plants. NYISO reports that 1,027 MW of peakers had ceased or limited their operation as of May 1, 2023, with an additional 590 MW scheduled to go offline by the 2025 deadline, all of them in New York City.

The peaker rule allows plants needed for reliability to remain operational until May 1, 2027, with a potential two-year extension to May 1, 2029.

NYISO anticipates improved generation margins in 2026 with completion of the 339-mile Champlain Hudson Power Express, which will carry up to 1,250 MW of hydropower from Quebec to New York City. If the project is delayed, or if more power plants are retired, or demand exceeds forecasts, the city could experience a reliability shortfall for up to 10 years.

Even with CHPE, "the margin gradually erodes through time thereafter as expected demand for electricity grows," the ISO said. And it noted that while CHPE will help summer reliability, it is not expected to provide any capacity in the winter. New York's winter electricity demand is forecast to increase over the next decade.

The decision to keep the Gowanus and Narrows plants operational was a last resort, made after alternative proposals failed to present viable solutions that could address the 446-MW deficiency and be installed before 2025.

Con Edison proposed installing roughly 16 miles of 345-kV underground cables and associated stations. The ISO said the proposal was rejected because the project would not be completed until "well after" the CHPE's anticipated in-service date.

Orenda, a renewable energy storage supplier, proposed a reliability must-run solution involving small battery storage projects interconnected with Con Ed's distribution system. However, the ISO deemed this output — a maximum of 27 MW over four hours, or up to 12 MW over the nine-hour duration of the need — insufficient. "The total capability of the Orenda batteries is less than the output of the smallest Gowanus or Narrows peaker," the ISO noted.

The ISO said it received no market-based proposals to solve the shortfall.

"NYISO is working very closely with the DEC, the Public Service Commission and NYSERDA [the New York State Research and Development Authority] as we address the reliability need in New York City and a reliable transition to renewable resources for the state," Nelson said. ■

PJM News

Report Questions Dominion IRP's Call for New Natural Gas Plants

By James Downing

A render of the proposed southern view of the Chesterfield Energy Reliability Center, adjacent to the existing Chesterfield Power Station in Chester, Va. | *Dominion Energy*

The Chesapeake Climate Action Network (CCAN) Action Fund on Thursday released a *report* arguing that Dominion Energy can meet growing demand for electricity in its territory with clean energy instead of building new natural gas plants, as it has proposed.

The report, which the environmental group commissioned from the consultancy Gabel Associates, pushes back against Dominion's pending integrated resource plan that was filed with the Virginia State Corporation Commission this spring. (See *Enviros Pan Dominion Integrated Resource Plan*.)

"Unfortunately, Dominion's plan is not compliant with laws passed by the General Assembly in 2020 and 2021, including the Virginia Clean Economy Act and regulatory directives to account for economic externalities associated with air pollution," the report said. "As an example, Dominion intends to build 1,000 MW of new gas-fired generation capacity in Chesterfield County by 2027 even though doing so will generate more than 2 million tons of additional carbon emissions each year."

The utility expects peak demand to grow by 2.32% and overall energy consumption by 3.25% annually, which the report said could be met while retiring coal- and gas-fired power plants using PJM's generator replacement process to avoid queue delays, adding battery storage at existing sites, expanding behind-the-meter solar and increasing energy efficiency and demand response.

"Dominion has a chance to cut costs for Virginians by $28 billion and slash greenhouse gas emissions by 52 million tons over the next decade without compromising system reliability simply by switching out old fossil fuel plants for new solar panels and battery systems," Gabel Associates Vice President Adrian Kimbrough said.

Dominion's load growth projections are based on assumptions including significant growth in data centers in its territory, though the report said it is unclear if this growth is made up of projections or actual contractual arrangements. The projections also include efficiency and demand-side management, but the report questions whether those could be higher and lead to lower load growth.

The IRP has already seen proceedings in the SCC; in a brief filed in late October, Dominion said it had picked a middle path of data center growth out of three scenarios, which was reviewed by PJM, as the commission has required in the past. The first five years of that forecast are more certain than the later 10 covered in the IRP, the utility said.

CCAN and Gabel proposed an alternate resource plan, which would hold constant the current and contracted renewables Dominion has while accelerating the retirement of 8.5 GW of fossil fuel capacity that has operated for 20 years. The retired capacity would be replaced with a range of solar, including the company's own utility-scale projects, behind-the-meter resources and contracts with third-party developers. Dominion would also need to add battery storage to sites of existing and planned renewable energy generators using PJM's Surplus Interconnection Queue.

The report does not get into specifics for what should replace the retiring capacity and avoided new fossil plants because it is meant to provide a high-level alternative to Dominion's proposals.

CCAN said the report bolsters the argument that a proposed 1,000-MW natural gas plant in Chesterfield is not needed. The group and some local citizens are opposing the plant's construction.

Dominion told the SCC last month that dual-fuel combustion turbines like the one proposed for Chesterfield are "currently the most cost-effective and reliable resource" to meet a future long-duration winter event or capacity shortage. Other parties including Advanced Energy United and the Sierra Club have pushed back on its plans for new gas plants.

"Reliability is paramount to the company, and the significant increase in the load forecast, coupled with events like Winter Storm Elliott, have highlighted the need for dispatchable generation and the reliability benefits of natural gas units" to serve the company's customers, Dominion said in its filing.

Dominion said the IRP is not the proper venue to litigate the need for specific power plants, as the SCC does not approve or reject any actual plants in such proceedings. The firm will have to apply for a certificate of need and public necessity for specific plants, which is where the need for actual powers is properly debated, it said. ■

PJM News

FERC Continues Deliberations on PJM Real-time Values

By Devin Leith-Yessian

FERC on Thursday deferred making a decision on PJM's proposal in response to a 2021 order directing the RTO to show cause as to why its rules regarding parameter-limited offers are just and reasonable (*EL21-78*).

The docket was on the agenda for the commission's monthly open meeting, but was struck.

FERC had found that PJM's tariff does not require that offers be selected to arrive at the lowest total costs based on parameter-limited offers, but instead requires that resources be committed based on the lowest-cost offers. It also found that the RTO's governing documents did not appear to define what should happen if a generator fails to operate according to the parameters in its selected offer. (See *FERC Issues Show-cause Order on PJM Parameter-limited Offers*.)

"PJM is disappointed that FERC did not act on this show-cause order today," RTO spokesperson Jeffrey Shields said. "PJM will continue, in the meantime, to work with generation owners to ensure that unit operating parameters are being updated in an effective manner to inform PJM Dispatch of generator availability, particularly during periods of cold temperatures during the upcoming winter."

The RTO and its stakeholders have been eagerly awaiting a decision. On the day before the commission's meeting, the PJM Markets and Reliability Committee opted to delay a vote on two competing proposals to define how offers will be selected under the multi-schedule modeling functionality the RTO is planning to add to its market clearing engine. PJM and its Independent Market Monitor had filed a joint motion for expedited action on Sept. 11, urging the commission to "issue an order as soon as practicable."

| © RTO Insider LLC

Shields said it's still expected that the MRC will move forward with a vote in December.

"PJM stakeholders voted to postpone the vote by one month, so a stakeholder vote is still scheduled to take place in December. While a FERC order in EL21-78 would have been informative, it is not necessary for stakeholders to proceed with a vote," he said.

During the Electric Gas Coordination Senior Task Force meeting Nov. 14, Paul Sotkiewicz, president of E-Cubed Policy Associates, said real-time values — which the Monitor and PJM proposed to replace with temporary exceptions in response to the commission's show-cause order — could be the "linchpin" of addressing the incongruities between the gas and electric markets.

The joint proposal would remove the deadline for submitting temporary exceptions by the close of the day-ahead market to allow them to be used in the real-time market as well.

"The simple solution is to ... permit real-time submissions for temporary exceptions," the Monitor wrote. "This would let resources communicate to PJM their changed operational capability without delay, while maintaining the tariff requirements and standard for review that protect against withholding."

Monitor Joe Bowring told *RTO Insider* that real-time values would create a pathway for market sellers to notify and explain to PJM that they are unable to operate according to the schedule that they were dispatched and seek an exception from energy market penalties for not being able to do so. He said a similar capability already exists in the day-ahead market, but if a resource is affected by an issue affecting their performance in real time, no corresponding structure exists.

"What we were asking for is to expand the existing process into the real-time [market]," Bowring said.

The real-time values proposal would not interact with the capacity market and would not provide an exception from Capacity Performance penalties during a performance assessment interval, Bowring said. ■

North Carolina Regulators Combine Duke's IRP with Carbon Plan

By James Downing

The North Carolina Utilities Commission issued an order Monday combining Duke Energy's integrated resource plan with its carbon plan.

The regulator approved the firm's first carbon plan late last year, separately from the IRP process. (See *North Carolina Regulators Approve Duke's 1st Carbon Plan*.)

For regulatory efficiency, the two are going to be rolled into one process, with Duke filing a proposal earlier this year after consulting with the NCUC's public staff for weeks.

The utility will have to file a consolidated carbon plan and integrated resource plan (CPIRP) every two years for approval, which will have Duke continuing to meet its obligation to serve load in its territory while making long-term plans for carbon neutrality. State law requires a 70% cut in carbon emissions by 2030 and carbon neutrality by 2050.

The plans will have to include several different resource portfolios so that a range of demand-side, supply-side, energy storage and other technologies can be fairly evaluated in the process. Those plans are required to either maintain or improve upon the adequacy and reliability of the existing grid.

The NCUC agreed with the North Carolina Attorney General's Office that at least one of the plans Duke submits needs to meet the 2030 carbon target. Legislation gave the commission the authority to delay that target, and it needs the planning data to make that decision, it said.

The CPIRPs will require near-term action plans that identify specific investments in the demand and supply sides, procurements and retirement activities, and upgrades to the transmission system needed to interconnect new resources. The attorney general suggested that Duke be required to identify whether those near-term plans can support the resource portfolios in the CPIRP and, if not, any additional activities that would bring the company on track to meet longer-term carbon goals. The commission agreed.

The NCUC declined to include transmission planning into the CPIRPs directly, but it agreed with some intervenors that the carbon plans should inform it. Duke will have to discuss how the most recently approved CPIRP was incorporated into its transmission planning process, the regulator said.

The CPIRP process includes some stakeholder meetings before it is filed with the NCUC and that is meant to produce a report on what was discussed during that time. The NCUC said that the report will have to include a list of which stakeholder ideas Duke decided to adopt in its initial plan, which will give the commission some clarity on how well the early stakeholder discussions are working.

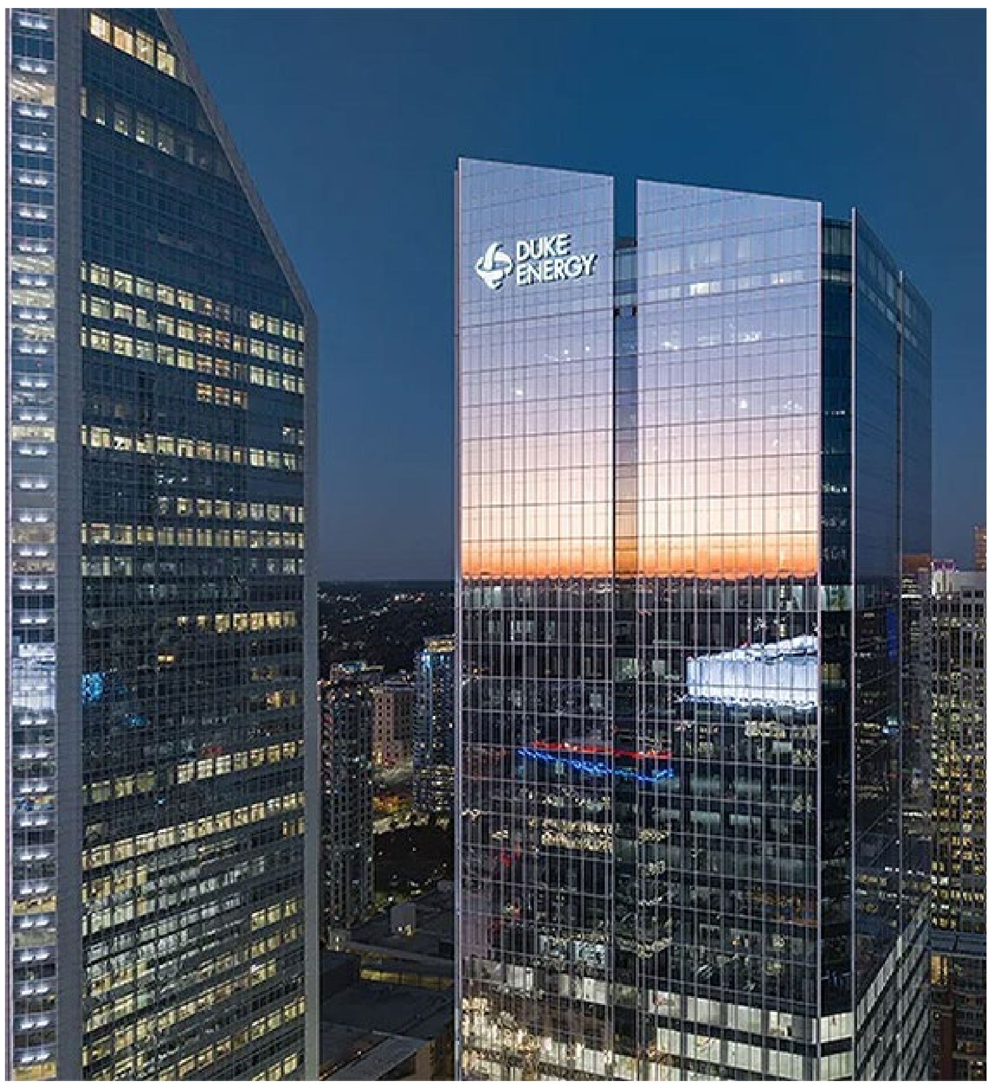
The Clean Energy Buyers Association asked the NCUC to require Duke to include information on the costs and benefits of participating in the Southeast Energy Exchange Market (SEEM) and whether participating in an RTO, especially PJM (which neighbors Duke's territory), would be cheaper overall.

Duke opposed CEBA's request, saying nothing in the relevant statutes on carbon plans and IRPs discusses wholesale market participation. The utility also said it would only join an RTO if state or federal legislation required that, which is not the case now.

IRP modeling is also not capable of capturing the 15-minute granularity of SEEM transactions over a long planning period, Duke said.

The current rules are already enough for Duke to consider wholesale issues, and requiring the kind of study CEBA wants would only add unnecessary costs given the lack of legislation requiring RTO membership.

Duke already filed its initial CPIRP in August, and it said it followed the proposal that was pending at the NCUC at the time. The commission deemed that August filing in compliance with the order issued Monday. ■



| *Duke Energy*

PJM MRC/MC Briefs

By Devin Leith-Yessian

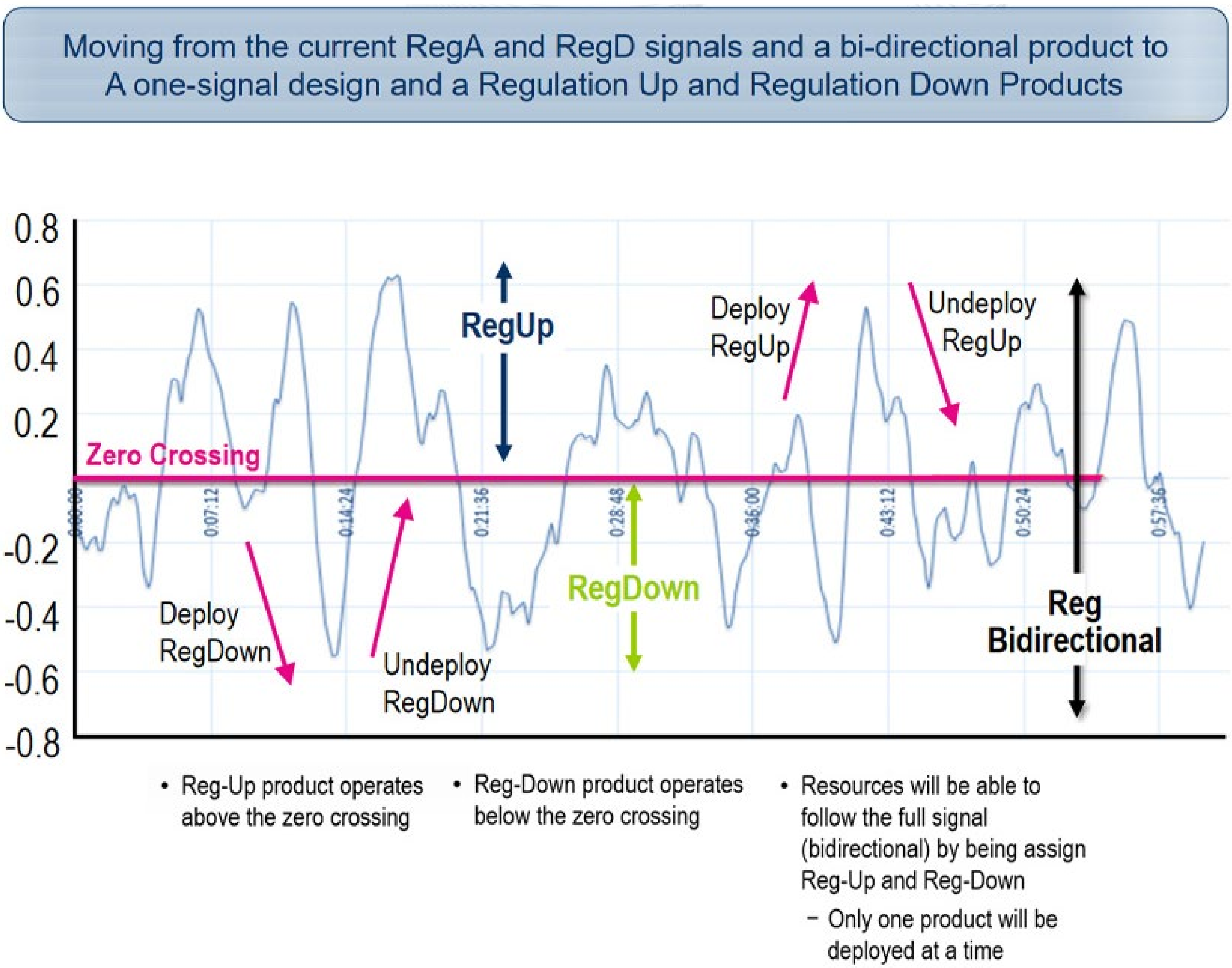
Vote to Close Clean Attribute Group Fails

VALLEY FORGE, Pa. — The Markets and Reliability Committee voted against sunsetting the Clean Attribute Procurement Senior Task Force (CAPSTF), instead putting the group on track to be on hiatus as a state-led working group continues discussions outside the PJM stakeholder process. (See "Stakeholders Mixed on Sunsetting Clean Attribute Procurement STF," *PJM MRC Briefs: Oct. 25, 2023.*)

Task force facilitator Scott Baker said PJM dropped its recommendation to sunset the CAPSTF given ongoing discussions the states are having with FERC staff to explore whether a forward clean energy market (FCEM) would fall under state or federal jurisdiction.

If the issue is determined to fall under the commission's purview, it would return to the PJM stakeholder process to determine what form it would take and how it would operate. After Baker said PJM would not pursue sunsetting the task force, Paul Sotkiewicz, president of E-cubed Policy Associates representing JPower USA, motioned to sunset, receiving 34% support.

The FCEM design would allow clean energy attributes to be purchased and traded by states and entities with sustainability targets and provide a centralized platform for existing renewable energy credit (REC) sales. PJM currently administers a registry of RECs through the subsidiary PJM EIS (Environmental Infor-



A PJM graphic details the bidirectional price signal that would be added to the regulation market under the proposal recommended by the Regulation Market Design Senior Task Force. | *PJM*

PJM News

mation Services), but it does not facilitate the trading of credits.

Constellation's Juliet Anderson said that if a Forward Energy Attribute Market design was determined to be FERC-jurisdictional, it could be returned to PJM stakeholders for consideration most efficiently through the existing charter of the senior task force.

Calpine's David "Scarp" Scarpignato said PJM task forces are meant to address specific topics over a specific period of time and the work envisioned for the CAPSTF has been complete. He argued that a new stakeholder group with a scope or charter more specific to any future needs would be better than leaving the task force open in case it can be restarted.

Endorsement of Multi-schedule Modeling Solution Deferred

Stakeholders opted to defer voting on two *proposals* to narrow the number of market seller offers entered into the market clearing engine (MCE) in order to allow multi-schedule modeling capability to be added to the engine without causing processing times to increase beyond the day-ahead market's 2.5-hour clearing window. The introduction of multi-schedule modeling is part of a larger overhaul of the engine under PJM's Next Generation Markets initiative. (See "Multiple Proposals Considered for Incorporation of Multi-schedule Modeling," *PJM MRC Briefs: Oct. 25, 2023*)

PJM Associate General Counsel Chen Lu recommended delaying the vote to the December meeting in the hope that an anticipated FERC order on parameter-limited offers and real-time values would provide more clarity on how the proposals would be viewed by the commission. However, the docket was pulled off the agenda for the Nov. 16 open meeting (*EL21-78*).

Both proposals would allow the day-ahead market to adopt the formula currently used in the real-time market to select one schedule from a resource to be modeled by the MCE. The main motion, sponsored by PJM in the Market Implementation Committee, would consider all offers with the aim of producing a schedule with the lowest total dispatch cost.

The alternate motion, jointly sponsored by GT Power and PJM, would use the same formula, but would mitigate resources that fail the three-pivotal-supplier test to their cost-based offers, disregarding any price-based offers. During emergency conditions, the proposal would also limit capacity resources to their price-based parameter-limited offers.

GT Power's Tom Hyzinski said the joint proposal would alleviate the potential "crossing curves" issue in PJM's design, in which the RTO would only consider offers at their economic minimum (EcoMin) value even if that offer would be more expensive at higher outputs. Highlighting the topic during the Oct. 25 MRC meeting, Deputy Market Monitor Catherine Tyler gave an example of a resource where the price-based offer is cheapest at its 100-MW EcoMin but jumps to the $1,000/MWh offer cap when the resource is dispatched above 120 MW. In such a case, she said the cost-based offer should be selected even if it's more expensive at EcoMin.

Tyler said both PJM proposals could run into an issue in which dual-fuel generators may be selected to run on a schedule using a fuel that is not economical for a portion of the day. The Market Monitor/GT Power Group joint proposal is identical to the PJM/GT Power Group proposal except that the Monitor proposal allows generators to select the fuel they want to use while the PJM proposal has PJM choose the fuel.

Scarpignato said the proposals would go beyond fixing an issue identified by the Energy Management System vendor and would sacrifice some of the current flexibility in the day-ahead market. PJM's Keyur Patel responded that the status quo has the most optimal schedule selection process and there would be trade-offs to meet the technical requirements of adding multi-schedule modeling capability to the MCE.

Sotkiewicz urged PJM to explore whether hardware and software changes could resolve the computational limitations to allow the status quo schedule selection to be retained.

"We're sacrificing optimality on solutions because we're unwilling to make a lot of the investments in hardware, software, parallel processing," he said. "We're drifting away from optimality and we could pour more money into resources on this to get to the right answer."

Patel said PJM looks at upgrading its hardware every two to three years, but the benefits of replacing servers are limited as the software is integrated. He said solution times are expected to improve as the software is fine-tuned after being launched.

New Winterization Requirements Endorsed

The committee endorsed *revisions* to Manual 14D, which details operational requirements for generators, to require that resources prepare for winter conditions by either developing their own winterization checklist or following the list produced by PJM, which itself was expanded under the proposal. (See "Generation Winterization Requirements Endorsed," *PJM OC Briefs: Nov. 2, 2023*.)

The revised checklist added guidance for combustion turbine intake preparation, drawing from NERC's *Lessons Learned*. It prompts generation owners to assess safety hazards posed by snow and ice accumulation on wind and solar facilities, inspect commodities and resources that may be used in severe winter weather, and consider adding a "freeze protection operator" staff member to inspect critical equipment.

The revisions also included clarifying changes such as replacing definitions with references to corresponding sections of the governing documents, specifying that the critical information and reporting requirements include a need to notify PJM dispatch by phone and several administrative changes.

PJM Presents Regulation Market Rework

PJM's Danielle Croop *presented* the proposal recommended by the Regulation Market Design Senior Task Force (RMDSTF) to redesign the regulation market to have one price signal and two products representing a resource's ability to adjust its output up or down. The proposal carried 86% support at the RMDSTF during an August vote, with two competing proposals receiving 26% and 6%.

The new price signal would be easier for market participants to follow and would result in all resources having the same settlement process, Croop said. Resources would be able to participate as being only regulation up (RegUp), regulation down (RegDn) or capable of doing both. The current market design has two price signals: Regulation D for resources that can modulate their output almost instantly and Regulation A for longer deployments.

The proposal would also shift to a 30-minute clearing and commitment period, down from the hourly intervals used now; less testing required for new and returning regulation resources; a ramp-limited lost opportunity cost (LOC) calculation meant to avoid overestimating LOC; and a performance score based only on the precision of the response, rather than the average of the scoring of its response accuracy, delay and precision. The proposal would add an annual review of the market to consider if the changes the grid is experiencing during the clean energy transition necessitate any adjustment of the regulation requirement.

Croop said the new scoring method would tend to be stricter, but still accurately capture resources' performance when called upon.

The market overhaul implementation would be split into two phases, with the first year introducing all the changes except the RegUp and RegDn products, which would be added in the second year.

American Electric Power's Brock Ondayko said the proposal may impact the ability for energy storage to provide regulation service, as those resources would typically be able to provide both RegUp and RegDn but would only be able to move in one direction if they are fully charged or depleted.

Croop told *RTO Insider* that there wouldn't be a change to how batteries participate in the market, and they would be able to remain in the market when fully charged or depleted. However, they may experience a reduction in their performance score if they are not able to follow the price signal.

Carl Johnson, representing the PJM Public Power Coalition, said he was concerned the task force would work around the edges of an RTO proposal that FERC rejected in 2018 and was glad to see that an entirely new market design proposal came out of the group's deliberations. (See *FERC Rejects PJM Regulation Plan, Calls Tech Conference.*)

Independent Market Monitor Joe Bowring *presented* several concerns with the proposal, arguing that the bidirectional price signal is not fully developed. He also argued against calculating LOC based on how a resource is dispatched over multiple regulation intervals, preferring that it be reset for each half-hour period, and said PJM's approach would result in significant overpayment of opportunity costs.

"There is no good reason to approve a market design that has not been developed or tested. In addition, the joint optimization with the energy market would make the energy market less efficient," Bowring said.

PJM, Monitor Urge Participants to Complete Account Manager Migration

PJM's Chidi Ofoegbu *said* the Dec. 13 deadline for eDART accounts to be migrated to the new Account Manager (AM) software is fast approaching with less than a fifth of users completing the transfer process. Of the 7,933 accounts in eDART across 758 companies, 1,433 have a corresponding account in AM, representing a completion rate of around 18%. (See "Migration of eDART Accounts to New Platform Underway," *PJM PC/TEAC Briefs: Aug. 8, 2023.*)

Once the deadline arrives, active eDART accounts will have their access revoked and users will not be able to access their accounts, rendering them unable to create generation or transmission tickers, respond to data requests or view reports in eDART.

Bowring said it would be difficult to participate in PJM's markets and complete required tasks without access to the online tools.

"Key market functions depend on eDART. If you do not have access to eDART it's hard to see how you could function in the markets. ... The numbers now are frighteningly low given how close the deadline is," he said.

Members Committee

3 Revisions to Stakeholder Process Endorsed

The Members Committee endorsed revisions to Manual 34, which outlines the stakeholder process, to change the voting structure at the MRC and MC, clarify the relationship between the higher and lower committees, and set deadlines for adding items to committee agendas. (See "3 Changes to Stakeholder Process Proposed," *PJM MRC Briefs: Oct. 25, 2023.*)

Under *language* brought by Dayton Light and Power (DLP), the senior standing committees continue to vote on any main motions before considering alternates; however, those alternates would now be voted on simultaneously similar to the lower committees.

One of the two proposals by Exelon *clarifies* that the MRC and MC hold final authority on topics considered by task forces and the lower committees, which have the role of setting the order of proposal votes at senior committees. The other *revision* requires that requests to add items to committee agendas must be made at least seven days in advance and include a summary of any action sought by the committee in order to be considered timely. Committee chairs would retain discretion to consider untimely items should they be time-sensitive or the result of unforeseen disruptions, or non-voting items such as informational reports.

Several states objected to the two Exelon revisions and abstained from voting on the DLP proposal. Four industrial consumers also abstained on the DLP language. ■

SPP News

FERC Accepts Basin Tariff Revisions, Sets for Hearing

By Tom Kleckner

FERC this month accepted SPP's proposed tariff revisions for Basin Electric Power Cooperative's formulate rate template, suspending them for a nominal period, effective Nov. 14, subject to refund, and established hearing and settlement judge procedures.

The commission said in its Nov. 13 order that its preliminary analysis indicated the proposed revisions have not been shown to be just and reasonable and that they raise issues of material fact more appropriately addressed in the hearing and settlement judge procedures (*ER23-2836*).

FERC did find that a 50-basis point adder it previously granted Basin Electric for RTO participation still was appropriate, given Basin Electric's continued membership in SPP. It said that the cooperative's return on equity (ROE), inclusive of the adder, must remain within the zone of reasonableness during the hearing and settlement judge proceedings.

SPP filed the tariff changes in September after FERC said Basin Electric became subject to its jurisdiction when it readmitted Tri-State Generation and Transmission Association as a non-exempt Class A member in November 2019. Basin Electric proposed to revise its template to reflect a base ROE of 9.69% and the 50-basis point adder for its SPP membership and calculated an 8.65%-11.12% composite zone of reasonableness.

The cooperative also proposed to revise its template to reflect a capital structure of 48.22% equity and 51.78% long-term debt, based on the weighted average capital structure of transmission owners across the SPP region. Basin Electric claimed that because it is the largest non-governmental transmission owner by capitalization in SPP's Upper Missouri pricing zone, it is appropriate to rely on the weighted average capital structure used in all SPP transmission owners' formula rates.

The proposed ROE and capital structure would result in an increase to the 2022 annual transmission revenue requirement of $4.68 million, Basin Electric said. That is about 4% under its 2022 ATRR under the existing template.

Black Hills Settlement OK'd

FERC on Nov. 16 approved an uncontested settlement of Black Hills Colorado Electric's proposed tariff revisions to transition from a stated transmission rate to a forward-looking formula rate for transmission service (*ER22-2185*).

The commission last year accepted and suspended, subject to refund, the utility's proposed revisions, setting the proceeding for hearing and settlement judge procedures. An administrative law judge approved the settlement with intervenors Tri-State and Arkansas River Power Authority in September and certified the agreement to FERC on Oct. 4.

Commission trial staff supported the settlement, saying its approval "will resolve all issues set for hearing." They said the agreement provides "significant benefits to ratepayers," pointing to an ROE of 9.8% that was lower than the filed ROE of 10.44%.

Staff also said a fixed capital structure of 47% equity and 53% debt is "both reasonable and preferrable" to the company's as-filed proposal for variable capital structure. A three-year moratorium of "key components of the formula rate" avoids further litigation, they said. ■

FERC has accepted SPP's proposed tariff revisions for Basin Electric's formulate rate template. | *Basin Electric Power Corporation*

SPP News

Winter is Coming; SPP Says It Has No Concerns

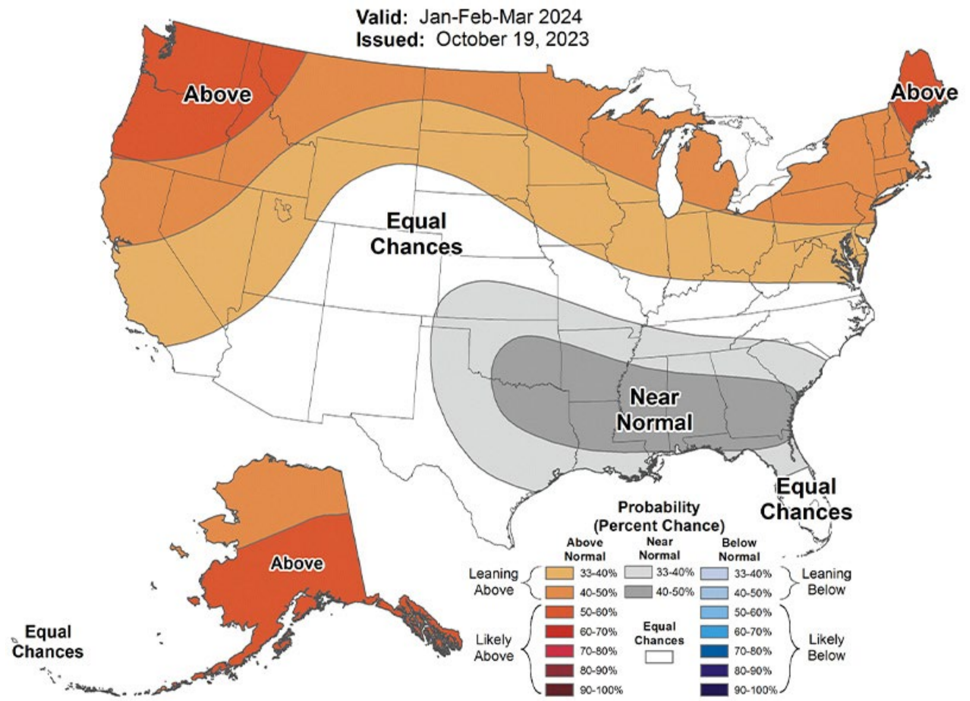
SPP says it has not identified any concerns within its 14-state footprint this winter that it is not capable of resolving.

Bruce Rew, senior vice president of operations, told stakeholders Nov. 13 the RTO also does not expect any fuel-supply or resource issues across its fleet.

"We are, however, continually performing studies to assess system changes and to develop ways to mitigate problems should any study indicate the potential for those to occur," Rew said during SPP's annual winter preparedness workshop. "Extreme weather can and has stressed our system from a capacity perspective, but we have procedures in place to ensure the grid remains stable."

He said SPP will take preemptive actions to prepare for worst-case scenarios should extreme weather occur, as has happened in each of the two previous winters. In February 2021, Winter Storm Uri forced the grid operator to shed load for the first time in its 80-year history. (See *ERCOT, MISO, SPP Slough Load in Wintry Blast*.)

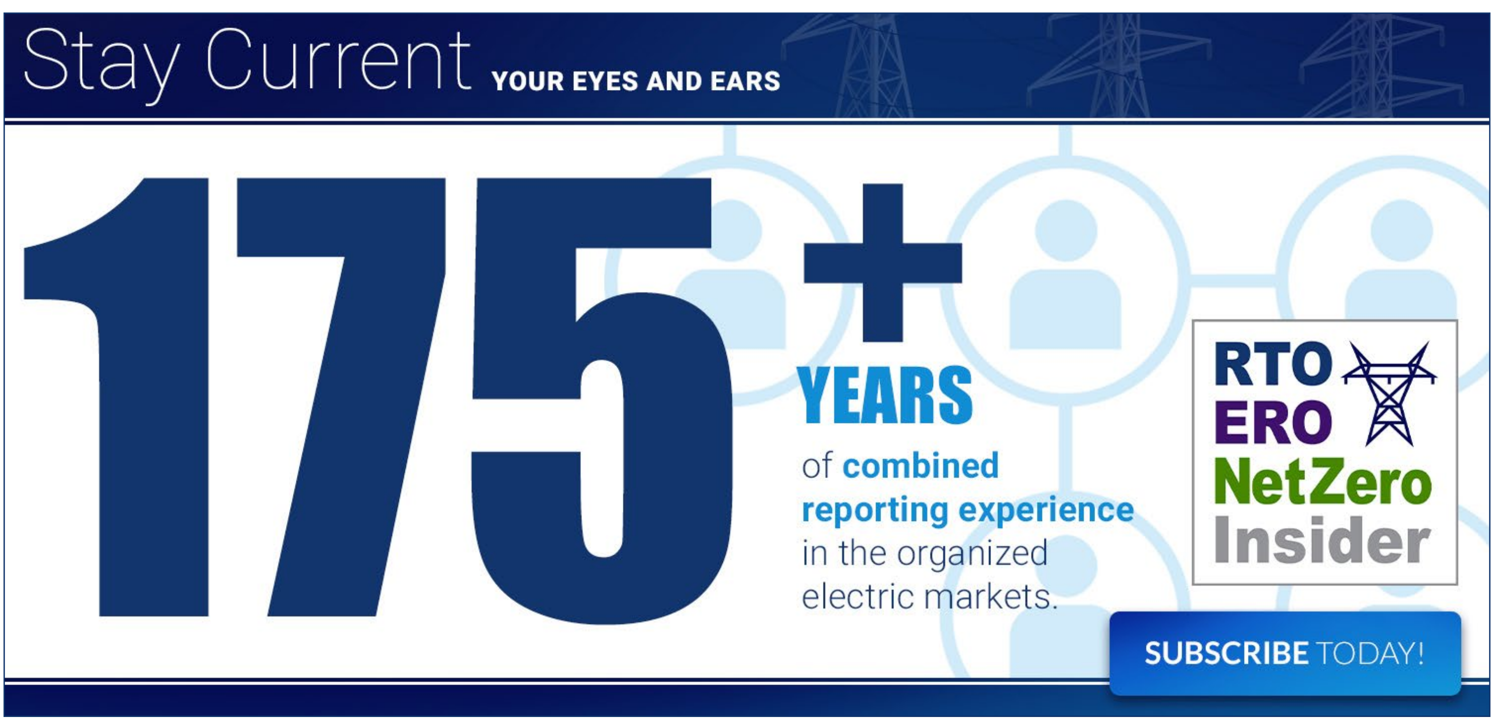
Rew said this year's winter assessment forecasts a peak load of 46 GW, just below last December's record peak of just over 47 GW. The assessment looked at typical load levels with normal expected outages.



Weather projections for the coming winter season | *NOAA*

SPP staff are forecasting near-normal temperatures in the central and southern portions of its region and above-normal temperatures in the North. They say a strong Arctic outbreak is less likely but that there is an increased chance of winter precipitation in the South, thanks to the El Niño weather pattern's strong subtropical jet stream. ■

— Tom Kleckner



SPP News

Stakeholders Approve Bulk of SPP's Markets+ Tariff

Greenhouse Gas Task Force Granted 8 Extra Weeks

By Tom Kleckner

TEMPE, Ariz. — Stakeholders interested in participating in SPP's Markets+ service offering in the Western Interconnection last week approved much of the draft tariff language they've developed together in recent months.

That tickles *SPP* attorney Chris Nolen, whose frequent comments about building "the best tariff ever" are being repeated by SPP staff and potential western stakeholders.

"We've moved, in my opinion, more efficiently, faster, better than I thought we would when we had our kickoff meeting," he said during a break in the Nov. 7-8 Markets+ Participant Executive Committee (MPEC) meeting. "It's been super impressive how all the market participants, everybody involved at all the stakeholder groups picked up really quickly on how it works, how it runs, how you make comments, how you get changes you want to see in the tariff language. I think we're in an excellent spot."

MPEC members endorsed chunks of tariff language that define how the day-ahead Markets+ will handle market transmission use, congestion management, transmission capacity obligations, market manipulation and confidentiality. The Interim Markets+ Independent Panel (IMIP), composed of three SPP directors, added its approval as well.

However, the Markets+ Greenhouse Gas Task Force was given up to eight weeks to approve draft language incorporating GHG emissions-related information in the market's reporting, price formation, commitment and dispatch. The group already has a conceptual framework.

The Pacific Northwest's only cap-and-trade program, Washington state's *cap-and-invest* initiative, has a Nov. 1, 2024, compliance deadline. By that time, affected entities need to have enough allowances to cover 30% of their 2023 emissions. (See "GHG Issue: 'Emissions Leakage'," *Markets+ Stakeholders Begin Tariff's Development*.)

A proposed option of making a supplemental filing at *FERC* once the cap-and-invest program's rules become clear failed to garner enough support. Washington's Department of Ecology, which is overseeing the program, has an ongoing rulemaking to be completed next summer.

SPP's Chris Nolen lays out timeline of Markets+ tariff to western stakeholders. | *© RTO Insider LLC*

Task force chair Mary Wiencke, with *The Public Generating Pool*, said she expects the rulemaking to be delayed by Ecology's concerns over Markets+'s final market design.

"There's a real cart-before-the-horse and a real chicken-and-egg issue here," Wiencke said. "Somebody has to go first, and so then the rules in the market design have to be jointly sort of put together. ... We need a market design to have rules also. This process is going to be iterative, no matter what."

"When you do that four to six weeks, or four to eight weeks, the pressure is really on all of us because we know that there's a pretty significant consequence if we don't get there," PowerEx's Mark Holman said. "We're either [filing a supplemental] or we're into a tariff delay that affects everything in this initiative. I like that pressure being on. I think it's worked well. We will have different resources that roll their sleeves up and not sacrifice the quality of the solution, but actually get it done."

The GHG delay could throw a kink in SPP's plans to have the tariff complete in December and take it to the RTO's Board of Directors in February. SPP hopes to receive IMIP approval Dec. 14 before taking it to the board; the tariff would be filed in the first quarter next year, assuming final approval.

The task force will report on its progress during MPEC's *Dec. 6-7 virtual meeting*, which once was a one-day call.

"We want to have the tariff and all the policy items done by December," said Carrie Simpson, SPP's director of seams and western services development. "However, to the extent that we've got some stuff that's still hanging around or there's a policy item that needs extra time, I don't know that January's a [hard deadline]."

No need to worry about the additional time afforded to the GHG task force, Nolen said.

"It's just complex, so it's taken a little bit when you plug it in to the broader market," he said. "It's new. We've never had to plug one in yet."

Nolen told MPEC if SPP receives the GHG tariff language in mid-January, staff will need only a week to "holistically consider" the tariff and to file at FERC.

"If we tried to wait and amend the filing after the fact, that brings up some of the complications with pushing this date," he said. "When the pens go down, we need eight weeks

SPP News

internally to run through that tariff and be sure that we wired everything out to the baseline tariff and everything works."

"The degree of collaboration and consensus that's been required to develop this volume of tariff language this quickly is tremendously encouraging," Antoine Lucas, SPP's vice president of markets, said after the meeting. "SPP and the Markets+ participants are striking a remarkable balance between speed and meaningful consideration in developing a market that works for all stakeholders."

FERC's approval of the Markets+ design would begin the market's second phase of development. At that point, SPP would acquire the necessary software and hardware, participating entities would fully commit to funding the market and they would be integrated into the system.

Go-live is targeted for October 2026.

WRAP, RTO West Advance

SPP also celebrated recent "significant" progress with the other prongs of its western expansion. It said an important element of the Western Power Pool's *Western Resource Adequacy Program* (WRAP) that it operates became operational Nov. 1, and the grid operator


Arizona Commissioner Nick Myers | *© RTO Insider LLC*

formally kicked off its RTO West development in Denver.

WPP says the WRAP is the first regional reliability planning and compliance program in the history of the West. Its operations program produces updated forecasts each season to help determine whether participants will have sufficient resources and enables those with a deficit to secure additional resources.

The RTO said the program will remain non-binding for an undefined time.

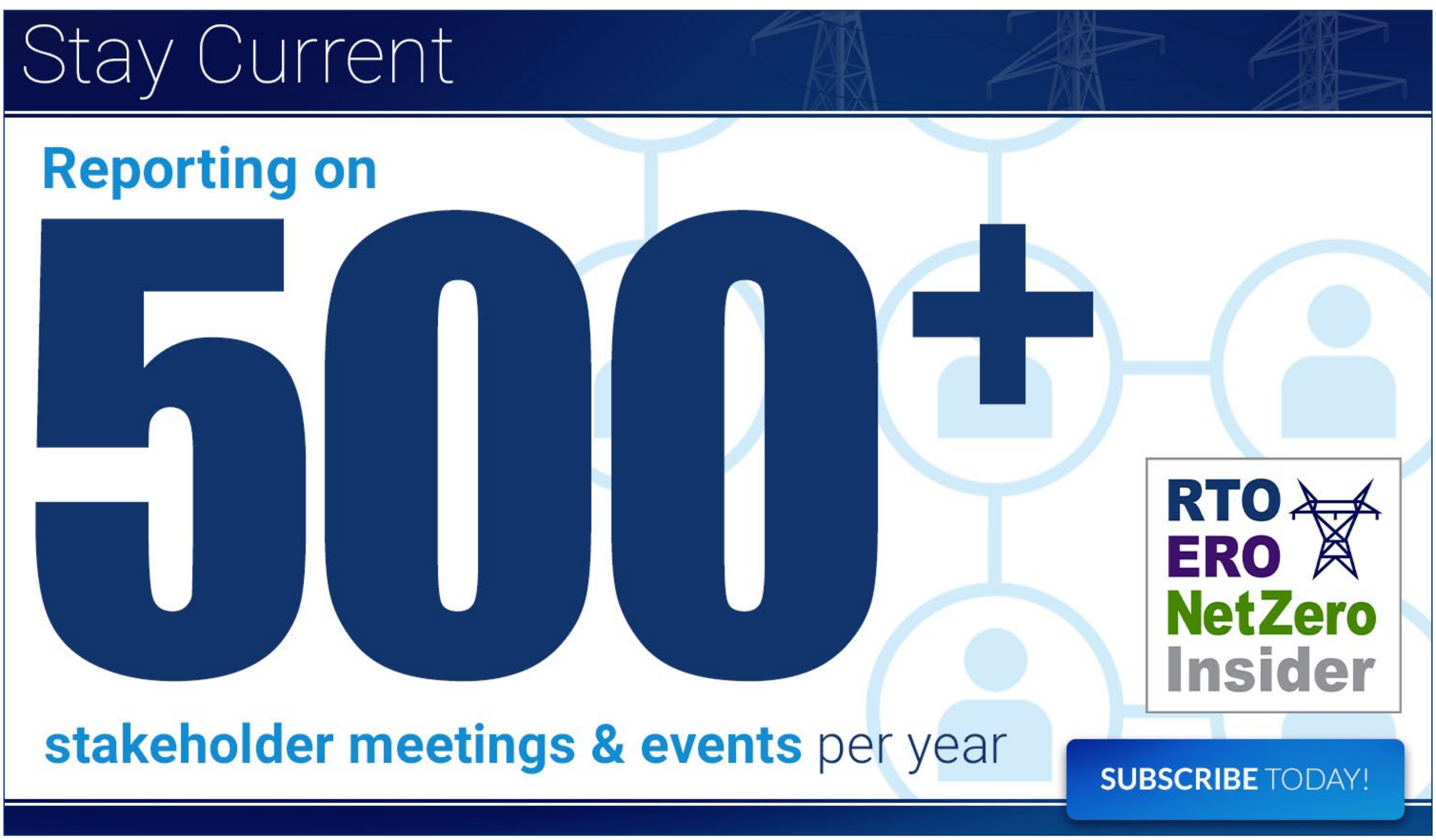
"SPP is grateful for our partnership with Western Power Pool and the opportunity to help assure resource adequacy for their member utilities," Casey Cathey, SPP's senior director of grid asset utilization, said in a *statement*.

On Nov. 9 in Denver, SPP hosted utilities that have committed to joining as members of its RTO in the Western Interconnection. The grid operator presented its plan to coordinate the utilities' integration into SPP's planning, reliability coordination, market and other services before operations are targeted to begin in April 2026. (See *WAPA, Basin Electric Commit to SPP's RTO West*.)

SPP's senior vice president of operations Bruce Rew, who leads the RTO expansion program, said the kickoff was a result of years of negotiations and planning.

"We're eagerly looking forward to the day that these plans come to fruition and we have the opportunity to bolster grid reliability, bring efficiency to planning processes and leverage the full potential of a single interregional market across two interconnections," Rew said.

Much of the RTO West's development will be handled through SPP's normal stakeholder process, staff said. ■



Company Briefs

Ørsted Parts Ways with 2 Executives

Ørsted last week announced that two members of its executive management team are stepping down.

CFO Daniel Lerup and COO Richard Hunter will step down, effective immediately, from their respective roles in what the company said was a "mutual agreement."

Rasmus Errboe, Ørsted's CEO of Region Europe and executive vice president, will serve as interim CFO. Andrew Brown, a member of the company's board of directors, has been appointed interim COO.

More: *Providence Business News*

Amazon Announces New Solar Farms

Amazon last week announced the construction of solar farms in Indiana, Michigan and Oklahoma.

The company said it will build its fifth renewable energy project in Fountain County, Ind. The 200-MW farm will support the company's local operations. No completion date was announced.

Amazon also announced its first solar farms for Michigan and Oklahoma. An 85-MW site in Van Buren County, Mich., and a 100-MW project in Kiowa County, Okla., will also help power the company's local operations.

More: *Inside Indiana Business*, *MLive*, *KFOR*

Altus Power Acquires Solar Assets in Carolinas

Altus Power, a commercial-scale solar provider, last week announced it has acquired 121 MW of solar assets in the Carolinas, investing over $120 million.

The company also posted third-quarter revenues of $45.1 million, an increase of 48% over the same period in 2022. For the full year, Altus reaffirmed its 2023 EBITDA guidance in the range of $97 million to $103 million and adjusted its margins to the high 50% range.

More: *pv magazine*

Nucor Seeks Net-zero Carbon Status

Nucor, a recycled-content steelmaker, last week revealed its net-zero greenhouse gas targets for 2050 and established a new interim target for 2030.

Nucor's net-zero 2050 and interim 2030 targets include Scopes 1, 2 and 3 emissions from the production of hot-rolled steel as defined by the Global Steel Climate Council. The new targets are more ambitious than Nucor's previous target of a 35% reduction in steel mill Scope 1 and Scope 2 greenhouse gas intensity by 2030, using 2015 as a baseline.

More: *Recycling Today*

Fujifilm, Bristol Myers Squibb Sign PPA with Texas Solar Project

Japanese conglomerate Fujifilm Holdings and US pharma giant Bristol Myers Squibb have agreed to buy the entire output of a 270-MW solar project being developed by National Grid Renewables in Texas.

The contracts are tied to the Blevins Solar Project, which is set to begin construction next year and state commercial operations in 2025.

Fujifilm has contracted 125 MW of the output, while Bristol Myers Squibb has clinched 145 MW.

More: *Renewables Now*

Federal Briefs

Biden Admin Uses Wartime Authority to Bolster EE Manufacturing

The Biden administration last week said that it used wartime authority — the Defense Production Act — to bolster manufacturing of energy-efficient heating and cooling technology.

The act gives the president the authority to mobilize a certain industry to advance national security, which the administration argues applies to producing more climate-friendly energy. The $169 million in funding will allow companies to construct factories to build heat pumps.

More: *The Hill*

FERC Issues Orders Regarding MISO Utilities

FERC upheld its decision last week to grant ITC Midwest an abandoned plant incentive for the Skunk River-Ipava 345-kV line. The line segment is part of MISO's $10 billion long-range transmission plan.

"We continue to find that ITC Midwest has demonstrated a nexus between its requested incentive and its planned investment and that the total package of ITC Midwest's incentives is tailored to its identification of risks and challenges associated with the project," FERC said.

Commissioner Mark Christie took issue with the abandoned plant incentive and dissented from the order.

More: *ER23-2033-001*

FERC Says Ameren Formula Needs Changes

FERC ruled last week that Ameren Illinois' annual informational formula rate update might need some changes after protests from three of its electric cooperative customers argued the utility was improperly recovering some of its costs in the rate.

FERC said Ameren must better explain its accounting for the costs of temporary workers, financial monitoring and other experimental research expenses, and why it included costs associated with demand response allocation uplift under an account for miscellaneous transmission expenses.

The commission also said Ameren needs to classify the costs associated with conducting market research surveys, credit investigations for new customers and electric vehicle education under different accounts. It should then assess whether the reclassifications change the formula rate, FERC said.

More: *ER23-1335-000*

State Briefs

CALIFORNIA

Report: Fairview Fire Triggered by Sagging SCE Line

A Cal Fire investigatory report released last week confirmed that a sagging Southern California Edison electrical line touched a communications cable, creating an arc that ignited the deadly Fairview fire in 2022.

Edison, in a report to the California Public Utilities Commission filed hours after the fire started on Sept. 5, 2022, said there was "very strong evidence" the utility's infrastructure ignited the blaze.

The report was provided in response to a subpoena from the attorneys for some of the fire's victims who have sued Edison, claiming negligence by the utility was responsible for the 28,000-acre fire that destroyed 22 homes and damaged five others, killed two people and injured several others.

More: *The Press-Enterprise*

PUC OKs PG&E Rate Increase

The Public Utilities Commission last week unanimously approved rate hikes for Pacific Gas & Electric, choosing the cheaper of two options presented to the board.

Electric and natural gas customers will see a $32.62 average monthly increase, effective Jan. 1. Electric-only customers can expect a $22.20 increase, while natural gas-only users would add $10.43 each month.

The commission approved a revenue requirement of $13.5 billion for the utility, an increase of $1.3 billion from its 2022 revenue requirement. That will help fund 1,230 miles of undergrounding power lines, as well as 778 miles of covered conductor on overhead lines. Additionally, it's expected PG&E will put $1.3 billion into vegetation management to reduce wildfires. Over $2.5 billion is slated for upgrading the utility's distribution system.

More: *Courthouse News Service*

KANSAS

Harvey County Bans Commercial Wind, Solar Projects

The Harvey County Commission last week unanimously approved regulation updates that will ban commercial wind and utility-scale solar projects in the county.

The revisions prohibit commercial wind and utility-scale solar projects while allowing limited-scale solar construction. Personal wind and solar energy installations, such as those used at residences, are permitted.

More: *Salina Post*

MARYLAND

Gov. Moore Appoints 2 New Environmental Positions

Gov. **Wes Moore** (D) last week announced two new positions aimed at addressing the causes and effects of climate change and other environmental threats.

Moore appointed Meghan Conklin as the state's first chief sustainability officer, who will focus on meeting the state's environmental goals. Moore also appointed Michael Hinson to be first chief resilience officer. That role will oversee existing work to prepare for, adapt to, mitigate and recover from all hazards and emergencies.

More: *The Associated Press*

Worcester County Sends Another Letter Against Wind Farm

The Worcester County Commissioners last week sent another letter to the Army Corps of Engineers in protest of offshore wind turbines since the Corps opened a public comment period ahead of making a decision to permit the project.

Commissioner Joe Mitrecic said increased government spending is a concern on top of Ocean City's fishing industry and other ocean-related activities. Fellow Commissioner Ted Elder said the wind farms would be a detriment to the state environmentally, financially and aesthetically, as the turbines will be visible from Ocean City and Assateague Island.

Meanwhile, BOEM's public comment period for the draft environmental impact statement on the project is open until Nov. 20.

More: *Ocean City Today*

MINNESOTA

Xcel Tx Line Cost More Than Doubles to $1.14B

The price of an Xcel Energy transmission line across southwest and central Minnesota has more than doubled to $1.14 billion, according to a filing with the Public Utilities Commission.

The higher cost of the Minnesota Energy Connection line reflects inflation and supply chain issues, plus other factors such as a longer route. If approved by the PUC, costs would be passed on to customers.

The earlier estimate of $528 million for the line came from a plan approved by the PUC in 2022 but drafted in 2019, company spokesperson Kevin Coss said. The original plan called for the line to be 140 miles long; however the proposed route is now about 175 miles. Plus, Xcel found needs such as additional substations to provide system reliability.

More: *Star Tribune*

NEW YORK

State Offers New OSW Auction, May Revive Troubled Projects

The state of New York will issue a new offshore wind solicitation on Nov. 30 with bids due in January 2024, the state government said last week.

The new solicitation will be open to all bidders, including those with existing contracts, and would allow companies to reoffer their planned projects at higher prices and exit their old contracts. The companies had warned they could cancel the power sales contracts after failing to convince the Public Service Commission to renegotiate the old contracts at higher prices.

More: *Reuters*

OHIO

Dayton Designated as LEED City

The city of Dayton last week received recognition for its sustainability work as the U.S. Green Buildings Council designated it as a LEED city with a platinum rating.

Dayton became the only city in the state and one of only four globally to earn the platinum status.

The city started the application process in 2021 and highlighted its renewable energy program for residents, protection of local aquifers and tree plantings.

More: *WKSU*

PENNSYLVANIA

Allegheny County Natural Gas Plant Canceled

Invenergy, which was developing the 639-MW natural gas Allegheny Energy Center project in Elizabeth Township, surrendered its installation permit and withdrew its application to connect the plant to the grid Nov. 9.

Invenergy cited "current market conditions" in a one-sentence statement about its decision and declined to elaborate.

More: *Pittsburgh Post-Gazette*

TEXAS

Federal Court Says State Violated the Law with Lax Emissions Limits at LNG

The Fifth Circuit Court of Appeals last week struck down a major air pollution permit issued by the Commission on Environmental Quality and said the state allowed improperly high emissions limits for Port Arthur LNG, a gas liquefaction and export terminal currently under construction on the Gulf Coast.

The panel ruled that the CEQ "acted arbitrarily and capriciously under Texas law" when it "declined to impose certain emissions limits on a new natural gas facility." The judges remanded the permit for Port Arthur LNG back to the commission for correction.

Sempra said it would continue construction on the terminal while it reviewed its options.

More: *Inside Climate News*

TotalEnergies to Buy 1.5-GW Gas-fired Power Plants

French oil and gas giant TotalEnergies last week announced a $635 million deal with Texas-based TexGen to acquire three gas-fired power plants with a combined capacity of 1.5 GW.

The plants include the 745-MW Wolf Hollow I combined-cycle gas turbine plant, the 604-MW Colorado Bend I plant and the 150-MW La Porte power plant.

More: *Power Technology*

WEST VIRGINIA

Mon Power Fined by PJM for Plant Outage

Mon Power paid a $40.5 million performance penalty to PJM for a December 2022 outage at its Harrison plant in Harrison County, according to testimony filed last week to the Public Service Commission.

According to the testimony, the plant's Unit 2 was offline for 17 days in December. It was brought back into operation on Dec. 24 at 7 p.m., during the height of the crisis.

In total, PJM lost 7,600 MW of coal capacity and 32,500 MW of natural gas during the peak of the event.

More: *West Virginia Public Broadcasting*

WISCONSIN

Green Bay Unveils Clean Energy Plan

The Green Bay Sustainability Commission last week announced the city's Clean Energy Plan for the rest of the decade and up to 2050.

The plan outlines the city's goals to reach 100% clean energy and carbon neutrality by 2050. The city's interim targets include cutting overall energy use by 20% and replacing 10% of fossil fuel energy with electric in municipal buildings, transitioning 65% of municipal electricity to carbon-free sources by 2030 and reducing total municipal fleet emissions 15% by 2030.

More: *Green Bay Press-Gazette*