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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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COVER: From left: FERC Commissioners Judy Chang, Mark Christie, Willie Phillips (chair), David Rosner and Lindsay See after the July open meeting, the first with all three new members appointed by President Joe Biden *(Page 5)* | *FERC*

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In this week's issue

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By Steve Huntoon

Hydrogen Flub

By Steve Huntoon

Steve Huntoon

Last November, *I wrote about* the insanity of green hydrogen electricity. And I'll return to that below.

But I'd like to start with green hydrogen generally, focusing on the first of DOE's funded "hydrogen hubs" located in — where else? California!

From the PR materials we, can piece together a somber tale. Let's start.

When is a Hub not a Hub?

The term "hub" is a misnomer. There will be 10 or more hydrogen production sites (at renewable energy facilities), with hydrogen transported to four ports, 60 truck/bus fueling stations, two power plants, etc. There does not appear to be a central location that would receive and store hydrogen for transshipment to end-use locations.

The *funding statute*, the Bipartisan Infrastructure Law, defines a hydrogen hub as a network of hydrogen producers and hydrogen consumers "located in close proximity." Instead, with this "hub," hydrogen *production sites* span most of the state, and hydrogen consumers in San Diego and Lodi are 473 miles apart.

So much for Congress' "close proximity" requirement.

Emissions reduction options (including carbon sequestration options)	Cost categories (USD tCO_2-eq^{-1})					Notes
	<0	0–20	20–50	50–100	100–200	
Energy sector						**Cost ranges are derived as ranges of LCOEs for different electricity generating technologies and the potentials are updated from UNEP (2017).**
Wind energy	2.1–5.6 (majority in <0 range)					Costs for system integration of intermittent renewables are not included, but these are expected to have limited impact until 2030 and will depend on market design and cross-sectoral integration.
Solar energy	2.0–7.0 (majority in <0 range)					
Nuclear energy	0.88 ± 50%					
Bioelectricity				0.86 ± 50%		Biomass use for indoor heating and industrial heat is not included here. Currently, about 90% of renewable industrial heat consumption is bio-based, mainly in industries that can use their own biomass waste and residues (IEA, 2020).
Hydropower		0.32 ± 50%				Mitigation costs show large variation and may end up beyond these ranges.
Geothermal energy		0.74 ± 50%				Mitigation costs show large variation and may end up beyond these ranges.
Carbon capture and storage (CCS)				0.54 ± 50%		
Bioelectricity with CCS				0.30 ± 50%		
CH_4 emissions reduction from coal mining	0.04 (0.01–0.06)	0.41 (0.15–0.64)	0.03 (0.02–0.05)	0.02 (0.01–0.03)		
CH_4 emissions reduction from oil and gas operations	0.31 (0.12–0.56)	0.61 (0.23–1.30)	0.07 (0.03–0.20)	0.06 (0.00–0.29)	0.10 (0–0.29)	
Land-based mitigation options (including agriculture and forestry)						**Potentials for AFOLU are averages for the period 2020–2050 and represent a proxy for mitigation in 2030. Technical potentials listed below include the potentials already listed in the previous columns. Note that in Table 7.3 the same potentials are listed, but they are cumulative over the cost bins.**
Carbon sequestration in agriculture (soil carbon sequestration, agroforestry and biochar application)		0.50 (0.38–0.60)	0.73 (0.5–1.0)	2.21 (0.6–3.9)		Technical potential: 9.5 (range 1.1–25.3).
CH_4 and N_2O emissions reduction in agriculture (reduced enteric fermentation, improved manure management, nutrient management, rice cultivation)		0.35 (0.11–0.84)	–	0.28 (0.19–0.46)		Technical potential: 1.7 (range 0.5–3.2). GWPs used from AR4 and AR5.
Protection of natural ecosystems (avoid deforestation, loss and degradation of peatlands, coastal wetlands and grasslands)		2.28 (1.7–2.9)	0.12 (0.06–0.18)	1.63 (1.3–4.2)	0.22 (0.09–0.45)	Technical potential 6.2 (range 2.8–14.4).
Restoration (afforestation, reforestation, peatland restoration, coastal wetland restoration)		0.15	0.57 (0.2–1.5)	1.46 (0.6–2.3)	0.66 (0.4–1.1)	Technical potential 5.0 (range 1.1–12.3).
Improved forest management, fire management		0.38 (0.32–0.44)	–	0.78 (0.32–1.44)		Technical potential 1.8 (range 1.1–2.8).
Reduction of food loss and food waste						Feasible potential 0.5 (0.1–0.9). Technical potential 0.7 (0.1–1.6). Estimates reflect direct mitigation from diverted agricultural production only, not including land use effects.

Detailed overview of global net GHG emissions reduction potentials (GtCO2-eq) in the various cost categories for the year 2030. | *IPCC*

Making Global Warming Worse

This hydrogen "hub" is going to make global warming worse. Here's why.

This project is going to use electricity from 10 or more renewable production sites across California to make hydrogen, and then store and transport the hydrogen to, among other consumers, two or more power plants. *In my prior column*, I showed how the losses in converting renewable energy to hydrogen, storing and transporting the hydrogen, and then converting the stored medium back into electricity, would take 7 MWh of green electricity at the source to end up with 1 MWh of green electricity delivered to end-use consumers.

And that's what will happen here. Every 7 MWh of renewable generation at production sites that otherwise would have been delivered directly to the grid, displacing natural gas generation, instead will be diverted to this hydrogen "hub," ultimately becoming 1 MWh of renewable generation delivered to the grid. So, every metric ton of carbon emissions avoided at the point of consumption will result in 7 metric tons of incremental carbon emissions from non-displaced natural gas generation.

Does that make any sense to anybody?

Cost of Carbon Emission Reduction

This hydrogen "hub" is a $12.6 billion *project*. Let's ballpark a 10% annual revenue requirement for return of (depreciation) and return on capital, so $1.26 billion annually. *DOE says* this hydrogen hub will reduce carbon emissions by "2 million metric tons per year."

That can't be so for the reason given in the prior section, but giving DOE the benefit of the doubt, if we do the math, that's a cost of $630 per ton of carbon emission reduction.

Counterflow

By Steve Huntoon

That cost is a multiple of the per ton cost of dozens of other carbon mitigation options, including 10 in the energy sector alone, as *this IPCC table* (see page 1,254, Table 12.3, Energy Sector portion) shows. All listed options are $200/ton cost or less.

Which begs the question, why spend many billions on a hydrogen "hub" that, even assuming DOE's figures, still costs more than a multiple of myriad other carbon mitigation options?

Job Creation

DOE claims this hydrogen hub will create 90,000 permanent jobs. This appears to be typical sleight of hand that ignores the fact that what taxpayers must pay for this program will reduce their disposable income, thereby reducing their spending and thereby reducing the jobs their spending would otherwise support. And those would be jobs providing products and services that people actually choose to pay for, instead of jobs artificially created by government agencies using taxpayer money.

Let's take an example: *DOE says* the hub will fund 5,000 hydrogen trucks and 1,000 hydrogen buses. But the truck drivers and bus drivers driving new hydrogen trucks and buses instead would have kept driving diesel/gas trucks and buses. No new jobs.

Water

Have I mentioned *all the water* that will be needed for the electrolysis to produce hydrogen (9 kg of ultrapure water for every 1 kg of hydrogen)? This in a state not known for having a lot of spare water. Just sayin'.

Backup for Well Water Pump

Speaking of water, *DOE says* it "will use hydrogen to provide backup power to community well water pumps to ensure clean drinking water during power outages."

This use of taxpayer dollars is wrong for at least three reasons. First, the recipient, the Rincon Band of Luiseno Indians, is a small tribe (about 500 members) that owns Harrah's Resort Southern California — an enormous *hotel/casino/events center*. This tribe does not need subsidies from the rest of us.

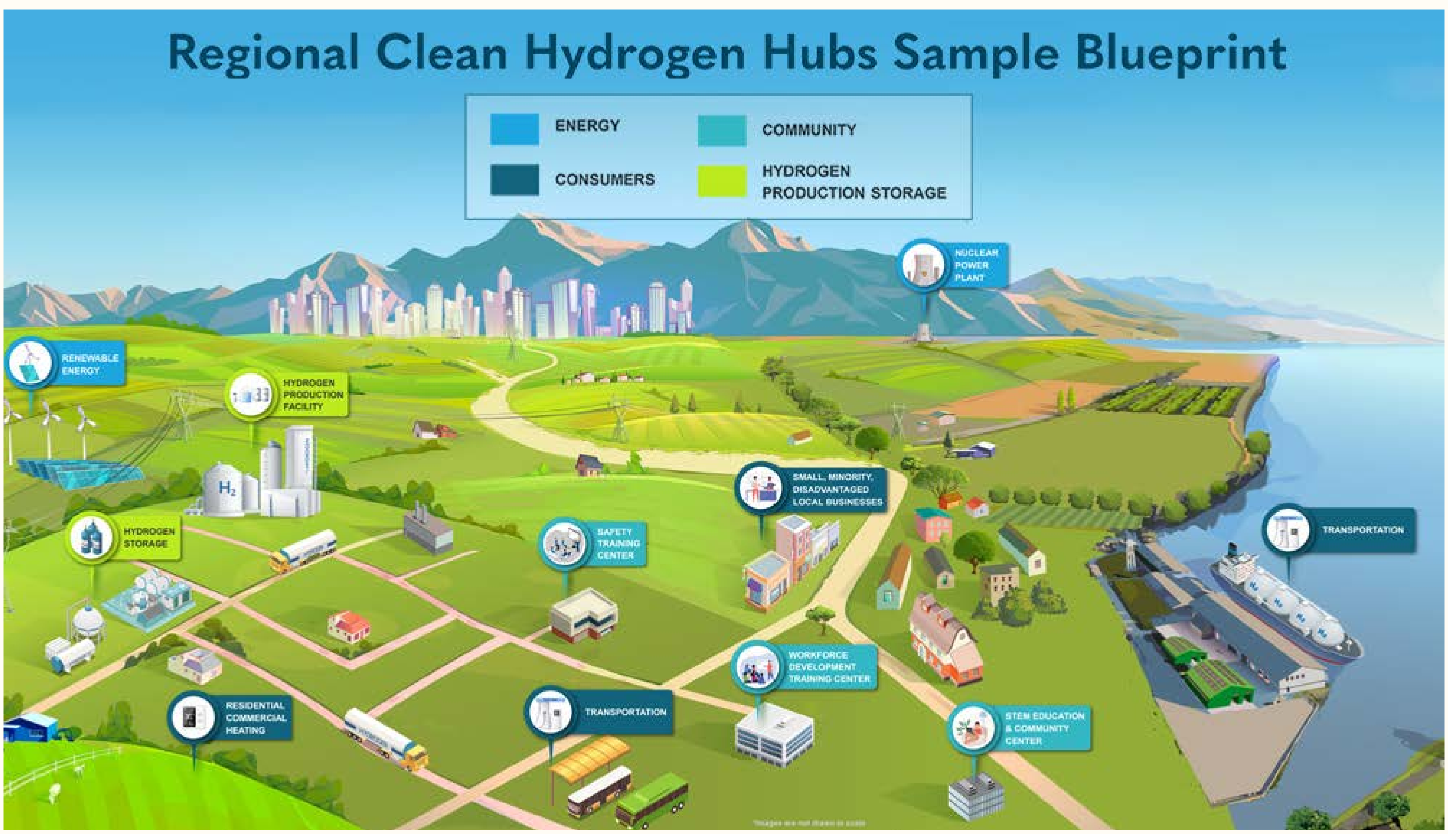
Second, the tribe's water well pump *already has* backup generation in the form of a 130-kW diesel generator. DOE's implication that the tribe would get backup generation it doesn't already have is wrong.

Third, the tribe already is using *taxpayer funds* for a new *solar/battery system*. Is the plan to substitute some sort of hydrogen system for this solar/battery system? Or perhaps have three systems (in addition to the grid): the diesel generator, the solar/battery system and the hydrogen system? Yikes.

OK I'll stop the hydrogen rant here.

P.S. Re. last column's P.P.S. about "(What's So Funny 'Bout) Peace, Love, and Understanding," I came across *this live* Elvis Costello cover where the Bangles show up. It seems like it's over at four minutes but somehow rocks on. And oh yeah, *the Boss with Bon Jovi*. And Sheryl Crow *covers it* not too shabby. And Bob Geldof — thank you for *Live Aid*! — gives a reading that explains it *before killing it*. Thank you again Bob Geldof! ■

Columnist Steve Huntoon, principal of Energy Counsel LLP, and a former president of the Energy Bar Association, has been practicing energy law for more than 30 years.



| *DOE*

FERC/Federal News

FERC Open Meeting Showcases Order 1920 Rehearing Debate

With New Commissioners, Phillips Open to 'Better Order' on Rehearing

By James Downing

From left: FERC Commissioners Judy Chang, Mark Christie, Willie Phillips (chair), David Rosner and Lindsay See after the July open meeting, the first with all three new members appointed by President Joe Biden | *FERC*

WASHINGTON — The ongoing debate around Order 1920 and its pending rehearing requests continued at FERC's monthly open meeting July 25, a day after it came up at a House oversight hearing. (See related story, *Order 1920 Debated at House Hearing with All 5 FERC Commissioners*.)

Order 1920 came after Order 2023, which set new standards for interconnection queues, and Order 1977, which implemented FERC's new backstop siting authority for lines in National Interest Electricity Transmission Corridors.

"I believe this suite of transmission reforms is balanced," Chair Willie Phillips said. "And I believe it will give us what we so desperately need to meet the demand that we know is going up in our country; to bring all of those resources that we know are waiting in the wings."

Phillips also noted that a group of state regulators from around the country supported Order 1920 in *a letter* to FERC this week (RM21-17).

But legal challenges to the order kicked off July 15 when FERC issued a *notice* that it had not acted within its 30-day statutory deadline for responding to rehearing requests. A group of Republican state attorneys general have filed an appeal of the rule with the 5th U.S. Circuit Court of Appeals — as have many other parties, including those that generally support it, in appellate courts around the country.

The commission did not say why it had not acted on the nearly 50 rehearing requests filed, but former Commissioner Allison Clements departed at the end of last month, and three new commissioners have joined since the order was issued in May.

One area even some supporters of the rule would like to see changed on rehearing is whether transmission providers should be required to file any alternative cost allocation schemes proposed by state regulators. Commissioner Mark Christie dissented from the order over the issue.

"We'll respond to every single issue raised" in the rehearing requests, Phillips told reporters after the meeting. "To the extent that there are improvements that can be made to the rule, I look forward to working with my colleagues on what those might be. I think you hear me joke all the time that it's a perfect rule, but I do believe that while it's a great step forward, we're just getting started. We can make improvements."

Christie said ensuring FERC gets to rule on any cost allocation proposal from states is a change that should be adopted on rehearing.

"That ought to be one of the top priorities in amending because I think there's going to have to be several major amendments to this rule to make it something that certainly would be acceptable to the states," Christie said. "And I think that would just be one of the many issues that needs to be changed. And I would hope that there will be a majority on FERC amenable to making those major changes because, otherwise, this rule is not going to work."

Phillips and Clements did not require any resulting state plans be filed in part because of a precedent in *Atlantic City Electric Co. v FERC*, they argued. Christie argued in the dissent that the case did not tie FERC's hands that much.

An *alternate interpretation* is before the commission on rehearing, with the Harvard Electricity Law Initiative's Ari Peskoe arguing that the precedent only stops FERC from forcing utilities to cede their rights to file rate changes under Federal Power Act Section 205.

"*Atlantic City* does not prevent the commission from amending the *pro forma* [Open Access Transmission Tariff] to include a process for filing all regional cost allocation methods approved by relevant state entities, regardless of the transmission provider's approval," Peskoe wrote in his rehearing request. "Imposing a process for filing relevant state entities' cost allocation methods would not 'deny [utilities] their right to unilaterally file rate and term changes.'"

Some state regulators have made similar arguments in their rehearing requests, noting that FERC has given their counterparts in SPP cost allocation filing rights.

But Christie also argued that additional changes would be needed for his support, including giving states the chance to approve the parameters and benefits used in the planning process. As written, he argued, the order will spread the cost of public policy lines to unwilling states, contrary to Phillips' continued insistence.

Christie noted that MISO Independent Market Monitor David Patton has repeatedly criticized the RTO's Long Range Transmission Planning process, which was cited as the model for Order 1920 by supporters. Patton argues that the LRTP consistently overstates benefits, which leads to too much transmission being built. (See *MISO IMM Knocks LRTP Benefit Calculations; RTO Poised to Add More Projects*.)

While Phillips and Christie have been engaged in an often-public debate on the merits of Order 1920, the majority on rehearing will include at least some of FERC's three new members who are still getting up to speed on its voluminous record.

"The commission works best when we have five members," Phillips said. "What that really means is that when you have five commissioners, they bring with them all of their history, all of their experience [and] all of their expertise to bear. And I believe you get a better result; you get better orders; you get better outcomes because of that diversity of opinion. And so, because we have five now, I think we will get an even better order on rehearing." ■

FERC/Federal News

Order 1920 Debated at House Hearing with All 5 FERC Commissioners

By James Downing

At full strength for the first time since the beginning of last year with the addition of Judy Chang this month, all five FERC commissioners appeared at a House oversight hearing July 24 during which representatives questioned them on Order 1920.

Rep. Jeff Duncan (R-S.C.) — chair of the House Energy and Commerce Subcommittee on Energy, Climate and Grid Security — praised Chair Willie Phillips for moving through the backlog of natural gas infrastructure projects but criticized the landmark transmission rule.

"We are concerned the commission has strayed from its responsibility as an economic regulator to an entity focused on assisting the buildout of so-called 'green energy' technologies," Duncan said. "This is happening despite the continued alarms from [NERC] and … grid operators across the country."

Duncan said Republicans are concerned that the order's "skewed 'categories of factors' approach to transmission planning" will drive up costs and threaten reliability. He argued that FERC prioritized Democratic-led state renewable energy targets, Biden administration goals and corporate clean power purchases.

Democrats on the subcommittee supported Order 1920, with Rep. Frank Pallone (D-N.J.), chair of the full committee, saying it builds on the progress of orders 888, 890 and 1000.

"Failing to plan is planning to fail," Pallone said. "And the basic principle of Order 1920 is that grid planning is essential to maintaining just and reasonable rates. I agree, and I've been encouraged by the reception the rule has received from nearly every corner of the political world except from congressional Republicans. It seems Republicans would prefer that their constituents be slapped with higher power bills because utilities are not required, for example, to plan for the impacts of severe weather on the grid."

Phillips said Order 1920 would unlock cheaper sources of power for customers while bolstering grid reliability.

"Order No. 1920 requires utilities to plan today for the factors that we know will drive tomorrow's reliability and affordability needs, while requiring that customers pay for new transmission only to the extent that they benefit from that infrastructure," Phillips said. "Let me say that again: If you don't benefit, you don't pay."

Commissioner Mark Christie dissented on Order 1920, and he explained his disagreement with the majority on how the order would spread the cost of implementing state policies across multistate RTOs.

"Order 1000 said that you can cost allocate public policy projects separately from reliability projects; this rule says 'no, you cannot.' That is a major, radical change from Order 1000," Christie said. "So, it didn't build on Order 1000; it was a radical break from Order 1000."

Under the order, public policy and reliability have to be planned for at the same time around a set of required factors, including state renewable targets, with one cost allocation formula based on a set of prescribed benefits for all those projects. Christie said that would spread the costs across all the states in an RTO.

From left: FERC Chair Willie Phillips, and Commissioners Mark Christie, David Rosner, Lindsay See and Judy Chang testifying before the House Energy and Commerce Committee | *House Energy & Commerce Committee*

FERC/Federal News

"The states can even agree on a different formula, and the rule says the transmission provider can just ignore it, so I don't think that's fair," Christie said.

Order 1920 does require that transmission providers give states a chance to weigh in on cost allocations, Phillips said later in the hearing. But as many rehearing requests pointed out, the transmission providers are not even required to file any proposal coming out of that with the commission. (See *FERC Order 1920 Sees Wide-ranging Rehearing Requests*.)

The order was approved in May by Phillips and former Commissioner Allison Clements. The three new commissioners did not get into the debate at the hearing, with Commissioner Lindsay See noting she is still staffing up her office.

See, who comes to FERC after serving as solicitor general of West Virginia, noted the changing legal landscape facing the commission.

"In response to the now-smaller margin of error for agency orders after the Supreme Court's recent decisions cabining agency discretion, I welcome the important check judicial review offers in our separation-of-powers system," she said, referencing the court's decision in *Loper Bright*, which ended Chevron deference. (See *Phillips, Christie Debate Loper Bright's Impact on FERC Order 1920*.)

Chang said her position working for the state of Massachusetts gave her firsthand experience highlighting the importance of having adequate infrastructure, efficient market frameworks and viable approaches to growing the economy while working to cut greenhouse gases.

"As a commissioner, one of my priorities is ensuring a robust and reliable transmission system, including the use of advanced technologies, to deliver affordable energy to all consumers," Chang said. "This is paramount to the economic growth of our nation, and this is how the United States will continue to lead the world and compete on the global stage in technological innovation and infrastructure development."

Commissioner David Rosner said a key task for the commission was maintaining reliability and affordability in light of the ongoing clean energy transition in terms of both supply and demand. That will require FERC to remain vigilant to the realities of the resources that power the economy.

"That means continuing to faithfully implement the commission's longstanding policy of resource and fuel neutrality to allow the next generation of technologies to play their role in the energy system," Rosner said. "It means continuing to harden the energy system to withstand evolving threats to reliability, including weather, physical and cyber risks." ■

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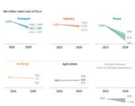

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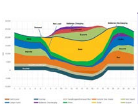

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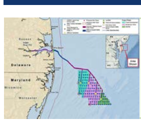

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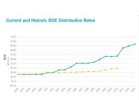

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FERC/Federal News

FERC Accepts All 6 ISO/RTO Order 895 Compliance Filings

By James Downing and Jon Lamson

WASHINGTON — FERC on July 25 approved all the jurisdictional ISO/RTO compliance filings with Order 895, which established rules for sharing credit information among the organized markets.

Issued in June 2023, *Order 895* directed the six grid operators to create procedures for sharing credit information about wholesale market participants with each other. The order is intended to "improve their ability to accurately assess market participants' credit exposure and risks related to their activities across organized wholesale electric markets."

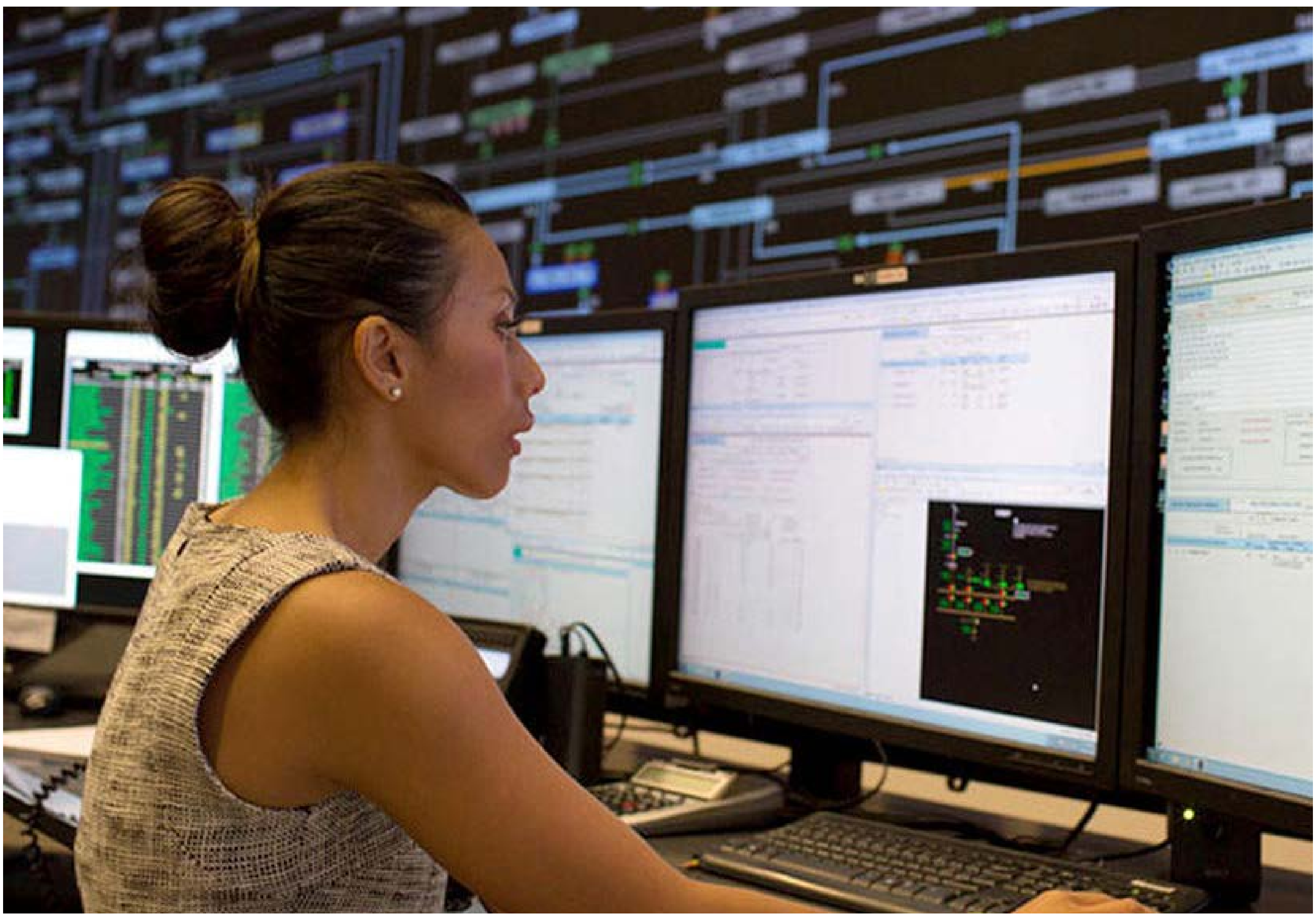
FERC said the rules will help prevent market participants from defaulting, thus forcing the ISO/RTOs to collect the costs from other market participants. Before the order, the grid operators' own confidentiality rules would have prevented them from sharing market participants' information.

"Market participants increasingly operate in multiple organized wholesale electric markets, whether directly or through affiliated entities, and their trading activities have become more complex and sophisticated," FERC said in Order 895. "These developments have complicated the ability of any individual RTO/ISO credit department to develop a complete, accurate and up-to-date picture of a market participant's overall financial condition due to real or perceived barriers to information sharing among RTOs/ISOs."

FERC found that CAISO's (*ER24-155*), ISO-NE's (*ER24-138*), NYISO's (*ER24-95*), PJM's (*ER24-156*) and SPP's (*ER24-289*) filings satisfied the order's requirements, including that they protect the data they collect from other markets. Their proposals went uncontested and, in some dockets, without any interventions.

While the commission found that MISO's proposal allows it to share information and to use credit information received from other ISO/RTOs, and the RTO said it would treat such information from another market as confidential, such language was absent from its tariff revisions (*ER24-165*). FERC directed MISO to submit a compliance filing in 60 days spelling that out in its tariff.

The accepted revisions went into effect the next day. Though they were issued at the commission's first open meeting with new Commissioners Lindsay See and Judy Chang, they did not participate in the orders. ■



Operator inside the ISO-NE control room | *ISO-NE*

FERC/Federal News

DOE Awards $371M to Regulators, Communities Grappling with New Tx

Grants Focus on Delivering Economic Benefits to Communities Under 20,000

By K Kaufmann

The Transmission Siting and Economic Development (TSED) grants that the U.S. Department of Energy's Grid Deployment Office announced July 24 are not — as most of the office's grants have been — targeted at building major new transmission projects or upgrading existing lines, said GDO Director Maria Robinson.

"This program is different," Robinson said during an advance press call July 23. "It's specifically designed to uplift communities impacted by transmission development, and we're doing that by making investments that generate benefits for them beyond resilience and reliability."

Funded by the Inflation Reduction Act, the TSED initiative will award $371 million to *20 projects in 16 states*, with grants unevenly divided between two programs. Four grants totaling $17 million will go to four state and county regulatory agencies to "accelerate siting and permitting of high-voltage interstate transmission projects," Robinson said.

The remaining $354 million is slated to go to 16 economic development projects, many in counties and towns with populations under 20,000 people, according to DOE.

So, in Baker City, Ore. (estimated population: 10,250) — near the path of the 500-kV Boardman-to-Hemingway (B2H) line — the Baker School District has been awarded $1.1 million to help establish a Lineman College and Training Hub to meet growing and future demand for utility, broadband and electric infrastructure workers. B2H will run 290 miles, connecting substations in Idaho and Oregon and delivering up to 1,000 MW of clean power in both directions, according to Idaho Power, which is building the line.

New Jersey's Economic Development Authority will be getting $50 million, with part of the money going to coastal communities that will be affected by the development of new transmission lines for offshore wind farms. The goal is for community residents to propose, vote on and lead the development of projects that will provide local benefits.

The funds will also be used for electrical apprenticeship programs and to build bike paths along existing transmission rights-of-way, which will link to other paths to state, county and municipal parks.

The map of DOE's Transmission Siting and Economic Development grants: These 20 projects in 16 states aim to accelerate state-level permitting of interstate transmission lines and provide tangible benefits to small communities affected by these large-scale lines. | *DOE*

"We're very focused on making sure utilities and developers are engaging affected communities that are involved with transmission," Robinson said. "Sometimes folks think about transmission projects as providing economic development in the short term — the construction piece, but these projects are really ensuring sustained economic development, not just during that transmission construction period. …

"This is one more piece in that overall puzzle … getting communities really invested in the idea of transmission by helping them see tangible effects through economic development."

The grants announced July 24 represent the first round of TSED funding. The IRA provided $760 million for the program, and Robinson said a second funding announcement could be released this year. She also stressed that once the contracts are signed and funds obligated, it would be difficult for any new administration to "change direction" on the program.

Strings Attached

But the TSED grants come with significant strings attached, Robinson said. For economic development grants, the awardees will not be able to receive the funds until the transmission projects affecting their communities have actually broken ground.

For example, Idaho Power has pushed back the B2H groundbreaking a few times, so development of the Baker School District's Lineman College and Training Hub could also be delayed.

For the siting and permitting awards, regulatory commissions and planning organizations will be able to get the money once they finalize their contracts with DOE, but they will have to commit to permitting the designated transmission lines in their states within two years.

Having that kind of hard and fast deadline could provide a challenge or new motivation for state regulators in Illinois and Wisconsin, both of which have been awarded grants to accelerate permitting on lines from the *first tranche* of MISO's Long Range Transmission Planning (LRTP) portfolio, a web of 345-kV lines crossing nine states.

As originally approved in 2022, the 18 projects in Tranche 1 are expected to come online between 2028 and 2030 at an estimated cost of $10.3 billion. (See *MISO Board Approves $10B in Long-range Tx Projects*.)

To help the Illinois Commerce Commission (ICC) up its permitting game, the state will receive a TSED grant of $8.2 million to streamline its approval processes while also protecting of the state's natural resources and incorporating community concerns into transmission siting and approval, according to the ICC. A major focus will be on updating customer-facing databases related to the LTRP lines in the state.

The Wisconsin Public Service Commission intends to use its $3 million grant to increase staff and resources to accelerate permitting for three LTRP projects. According to DOE's project description, the commission will "increase its outreach and engagement with the public, improve its coordination with other siting entities and develop plain language educational materials on high-voltage transmission lines."

The other two siting and permitting grants include:

- $4.5 million to the Pennsylvania Public Utility Commission to improve its siting processes for projects from PJM's Regional Transmission Expansion Plan crossing the state. The funds will go toward "expanding [PUC's] public and community engagement, participating in more site visits and public input hearings, and providing education and training opportunities to its staff."
- $1.7 million to Alamosa County in southern Colorado (estimated population: 16,655) to conduct an extensive analysis and broad community outreach to evaluate three potential corridors for increasing transmission capacity in the region and northern New Mexico. ■

FERC/Federal News

Electric Sector Added just 55 Miles of New Transmission in 2023

By James Downing

The U.S. electricity industry added just 55 miles of new high-voltage transmission to the grid last year, despite estimates the system will need to expand rapidly in the near future, Americans for a Clean Energy Grid said in a report released July 30.

"*Fewer New Miles: The US Transmission Grid in the 2020s*" was prepared by Grid Strategies with support from ACEG.

"The findings of this report are a wakeup call. With only 55 new miles of transmission built in 2023, we are not keeping pace with the growing demand for power," ACEG Executive Director Christina Hayes said in a statement. "The slowdown in new construction not only impacts our ability to meet future energy needs, but also risks increasing costs for consumers and reducing grid resilience. It is essential that we address these challenges to ensure a secure, reliable and affordable energy future for all Americans."

The U.S. Department of Energy's Transmission Needs Study found the grid should expand by 57% by 2035, while Princeton University's "Net-Zero America Study" found it would need to double or 80% of the potential greenhouse gas cuts from the Inflation Reduction Act would not be met, said the ACEG report. (See *Will DOE's Transmission Needs Study Spur New Regional, Interregional Lines?*)

While 2023 saw few miles of new lines built, the industry spent $25 billion on the grid (a record high), with 90% driven by reliability upgrades and the replacement of aging equipment. The decline has been felt for years, with the country building only 20% as much transmission so far this decade as it did in the early 2010s.

"This trend began over a decade ago, when the average of 1,700 miles of new high-voltage transmission built per year from 2010 to 2014 dropped to only 925 miles from 2015 to 2019, and has fallen further to an average of 350 miles per year from 2020 to 2023," the report said.

So far this year up to May, the industry has completed one major transmission line, adding 125 new miles from completion of the 500-kV Delaney-Colorado Transmission Project that links Arizona and California.

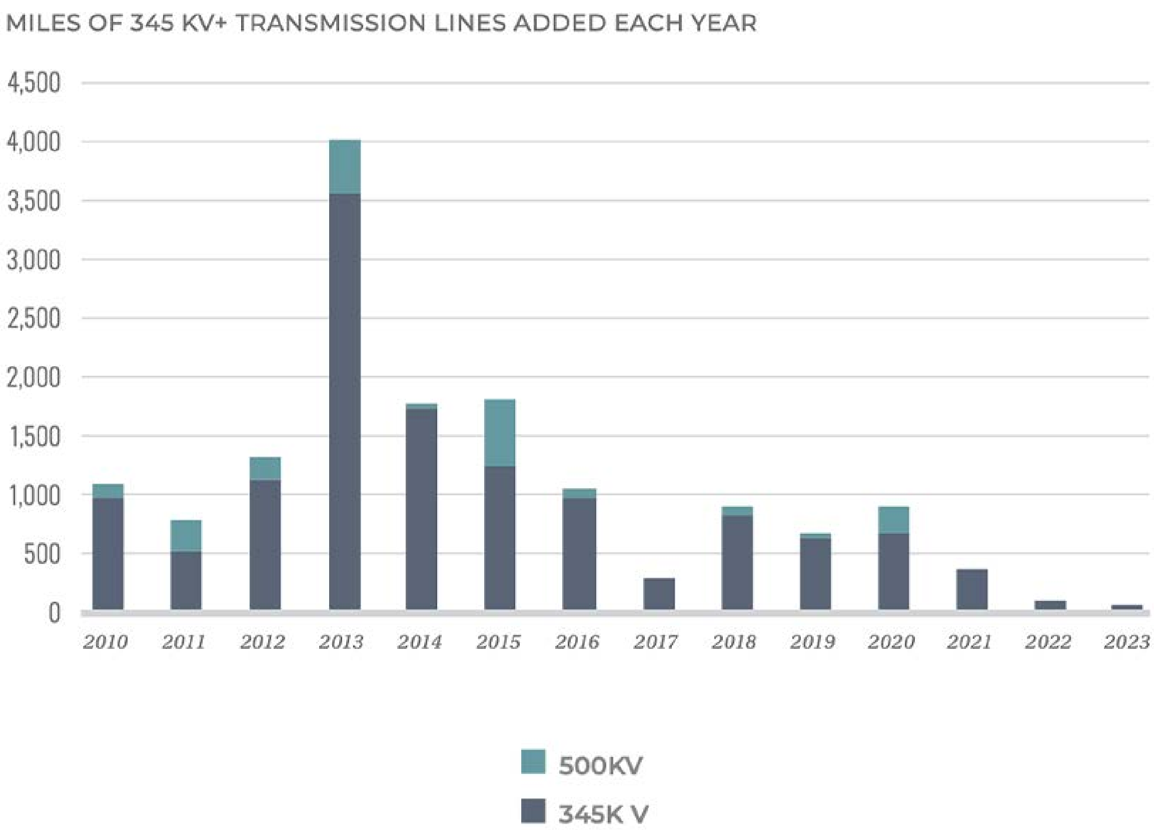
About 50% of recent spending is based on local planning criteria, which is usually below 345 kV and does not go through regional planning processes. Such lines focus only on reliability, ignoring maximized ratepayer benefits from multivalue projects, the report said.

The 2010s saw massive greenfield projects, especially in Texas and the Midwest. Texas' Competitive Renewable Energy Zone program saw $7.5 billion invested in ERCOT lines to bring wind power to population centers, cutting wind curtailment from 17 to 0.5% and leading to unexpected benefits like solar development in West Texas and electrification of oil and gas drilling in the regions.

MISO's Long Range Transmission Planning (LRTP) Tranche 1 Portfolio is another example, investing $10.3 billion to build out 2,000 miles of lines that offer at least 2.6:1 benefits to load.

Recent federal action like FERC Order 1920 and DOE's Transmission Facilitation Program to help finance new transmission lines should help, but the report said private capital needs to be invested to expand the grid.

"Utilities are still currently incentivized to prioritize low- voltage upgrades focused on reliability and asset replacement," the report said. "Both policymakers and regulators must capitalize on FERC's issuance of Order No. 1920 to ensure the momentum brought about by federal action truly changes the incentives for transmission investment and helps spur a massive investment in the construction of new high-voltage transmission lines to ensure a reliable and affordable transition to a cleaner grid." ■



A graph from ACEG's report showing total transmission lines added to the grid by year. | *ACEG*

CAISO/West News

NW Senators Urge BPA to Delay Day-ahead Market Decision

Ore., Wash. Delegations Ask Agency to 'Act Carefully and Deliberately' Before Choosing

By Robert Mullin

All four U.S. senators representing Oregon and Washington have urged the Bonneville Power Administration to delay its decision to join a Western day-ahead electricity market until developments play out further around SPP's Markets+ and CAISO's Extended Day-Ahead Market (EDAM).

In a July 25 *letter* addressed to BPA Administrator John Hairston, Democratic Sens. Jeff Merkley (Ore.), Ron Wyden (Ore.), Maria Cantwell (Wash.) and Patty Murray (Wash.) called on the federal power marketing administration to "act carefully and deliberately" before selecting a market.

The letter lays out the need for a "reliable, resilient and clean electrical grid" to achieve "the economic and environmental goals of the Pacific Northwest," including electrifying transportation and buildings and "meeting the demands of our growing manufacturing and data center industries."

It also points to the requirement for continued reliable service for residents and businesses in the face of "increasingly frequent extreme weather events."

The senators' letter additionally signals a preference shared by many state officials, environmental groups and large energy users across the West: that the region would benefit more from one organized electricity market than from two.

"In light of these major challenges, we share your view that 'Bonneville's customers and electricity consumers across the Pacific Northwest may achieve more benefits from participants coalescing around one regional market in the West,'" the senators wrote, quoting from a *policy letter* circulated by Hairston in January.

The letter comes about four months after BPA staff published a recommendation that the agency choose Markets+ over EDAM and just over a month before it is expected to issue a draft record of decision on its selection. A final decision is slated for November. (See *BPA Staff Recommends Markets+ over EDAM*.)

"Given ongoing uncertainties and the changing landscape with regard to both day-ahead electricity markets, we are concerned that BPA has expressed a preference for one market before complete and final information is available for clear decision making," the senators wrote.

Among those uncertainties, according to the senators, is the fact that the Markets+ tariff, which SPP *filed* with FERC in April, is still under review by a largely new slate of commissioners and could face deficiency letters that take additional time to resolve.

Although not cited in the letter, PacifiCorp, the first utility to fully commit to EDAM, has asked FERC to reject the Markets+ tariff without prejudice, letting SPP refile it without a provision that would allow Markets+ participants to contribute their transmission rights in nonparticipating systems. (See *SPP Markets+ Tariff Sparks Concerns for PacifiCorp, NV Energy*.)

FERC issued a mostly clean approval of CAISO's EDAM tariff last December.

The senators also raised a particularly heated topic in the West right now: the potential impact of seams between Markets+ and EDAM, which they said "may prove challenging to resolve, leaving ratepayers unable to realize economic and reliability benefits."

In response to this concern from stakeholders, both BPA and SPP have said they have ample experience dealing with market seams and would be able to reliably manage the transfer of energy between the two markets. (See *SPP's Experience with Seams Could Help Markets+*.)

14 Questions on 'Leaning'

The senators acknowledged one of BPA's primary reservations about committing to EDAM — CAISO's state-run governance — and it credits the agency with spurring a regional effort to increase the ISO's independence.

"The firm position taken by BPA that governance reforms were necessary helped inspire the West-Wide Governance Pathways Initiative last year. We see this effort has made real progress, culminating with NV Energy's recent announcement that it intends to join EDAM," the senators wrote.

For its part, BPA said July 18 that it has ramped up participation in the Pathways Initiative as the effort moves into its second phase, which is focused on changing California law related to CAISO's governance and establishing an independent Western "regional organization" to assume oversight of the ISO's EDAM and Western Energy Imbalance Market. But an agency official also noted that the move did not indicate BPA was pulling back from its "leaning" in favor of Markets+. (See *BPA Stepping up Participation in Pathways Initiative*.)

BPA's Bonneville Dam | © *RTO Insider LLC*

The senators asked BPA to clarify the reason for its leaning by responding to 14 questions with detailed analysis by Aug. 25. Among them are requests for BPA to explain which of the two day-ahead markets it expects would bring lower energy costs to the Northwest, provide the greatest improvement to grid reliability and reduce greenhouse gas emissions by the largest amount. The senators also asked if the agency's concerns about CAISO's governance would be assuaged by California's adoption of the Pathways Initiative proposal and, if not, what outstanding issues remain.

"BPA's decision to join a day-ahead market is monumental; BPA must be able to demonstrate that it is in the best interests of communities across the Northwest that are reliant on BPA for both power and transmission services," they said.

The senators concluded by saying that their letter should not be taken as favoring one market over the other.

"We share a strong belief that any decision of this magnitude warrants thorough evaluation of all options, including joining neither market at this time," they said. "BPA should refrain from making any draft or final decisions until there is less uncertainty and BPA can prove that any decision will provide the greatest benefit to the entire Northwest."

In a statement emailed to *RTO Insider*, BPA said it "understands the magnitude of this decision and is committed to ensuring we do the right thing for our customers and the region through the deliberative process we have engaged in so far. BPA is committed to fully evaluating the benefits and mechanics of day-ahead markets to accomplish this objective." ■

CAISO/West News

CAISO Advances Pathways Initiative 'Step 1' Proposal to Board Vote

Decision Earns Broad Stakeholder Support, Along with Some Sharp Dissent

By Ayla Burnett

CAISO will recommend that its Board of Governors approve a proposal that would eventually give the Western Energy Markets (WEM) Governing Body increased authority over the ISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM).

ISO staff discussed the recommendation July 23 during the second CAISO stakeholder meeting to discuss the West-Wide Governance Pathways Initiative's "Step 1" straw *proposal*, which would elevate the "joint" authority the Governing Body shares with the ISO board over WEIM/EDAM issues to "primary" authority.

The recommendation will advance that Step 1 proposal to a vote by the Board of Governors and the newly renamed WEM Governing Body on Aug. 13 — but some meeting participants expressed confusion over exactly what the two bodies will be voting on.

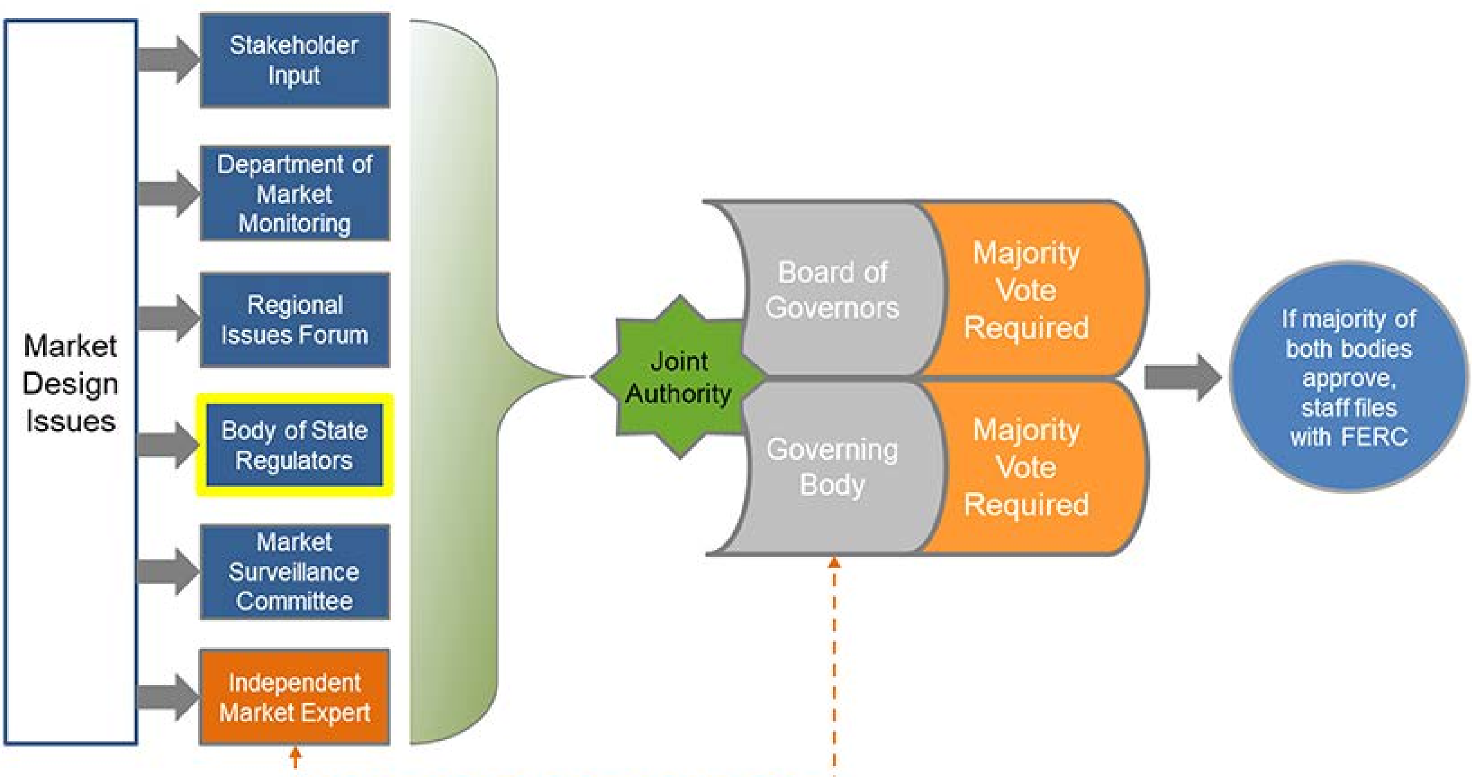
CAISO staff provided a summary of the comments received on the proposal, which showed overall support from several stakeholders and members of the Pathways Initiative's Launch Committee. Of the 31 entities that participated in indicative voting on the proposal, 22 offered support, six were neutral, one opposed and two had no position.

"We got almost complete agreement on the issues here, and I think that stakeholder process and the highly collaborative nature of what everybody did led CAISO to be able to make the recommendation to move forward with the Step 1 proposal to the governing bodies," Michael Colvin, director of regulatory and legislative affairs at the Environmental Defense Fund, said in the meeting.

Adam Schultz, manager of regional coordination at CAISO, summarized the feedback received from stakeholders through submitted comments. A key point of concern centered around the trigger mechanism, which would require that the FERC tariff filing needed to establish the Governing Body's primary authority wait until the EDAM obtains implementation agreements from a "set of geographically diverse" WEM participants representing load equal to or greater than 70% of CAISO's balancing authority area annual load in 2022, according to the straw proposal.

A few parties requested that the trigger mechanism be eliminated and Step 1 be implemented immediately. Other stakeholders suggested that the governance changes not take effect until one year after EDAM implementation.

"The goal all along has been to achieve the greatest independence for the EIM and now EDAM governance within California's existing law," said Doug Marker, a specialist in intergovernmental affairs at Bonneville Power



The ISO Board of Governors and the Western Energy Markets Governing Body plan to vote on the Pathways Initiative Step 1, which would shift primary authority to the governing body, August 13. | *CAISO*

Administration. "So if we have found that there is the ability to achieve greater independence for the EIM and EDAM, then it should not wait for critical mass of participants signing implementation agreements."

"I recognize that's a point that has been thoroughly discussed within the Launch Committee, but it is something that we flagged in our comments and would like to be brought before the boards when they consider this in August," Marker added.

'Extremely Frustrating'

Several stakeholders also took issue with the process used to develop the Step 1 proposal.

Jessica Zahnow, of Puget Sound Energy, said WEM entities were not adequately engaged or represented in the process.

"There's some very material items that haven't been addressed, and to just tell us that you think they are addressed and you're going to continue forward is extremely frustrating. I don't even know personally what the joint bodies are voting on," Zahnow said. "The language needed to effectuate this proposal has not even been developed or put before us, and when told that the Launch Committee has already vetted these issues, they did so behind closed doors and this is the first time that most of us have seen this fully formed offering at CAISO."

Launch Committee Co-Chair Kathleen Staks, director of Western Freedom, noted that development of the Step 1 proposal was addressed in several of the initiative's monthly public stakeholder calls and included input submitted from multiple public comment periods. Burton Gross, legal counsel at CAISO, provided further explanation.

"What's going to go to the board and the Governing Body for consideration is the proposal as written as a principle, and that is not going to be final," Gross said. "As the trigger gets closer … we would then put in a set of governance documents that are designed to implement the proposal before the board and the Governing Body for approval."

An ISO spokesperson clarified to *RTO Insider* that the Step 1 proposal to be voted on Aug. 13 will set forth the proposed governance terms. If approved, the ISO will prepare revisions to the documents that implement the governance terms in a public process.

Marker also reiterated prior concerns about the level of independence the Step 1 governance model achieves. (See *CAISO Kicks Off Stakeholder Process for Pathways Initiative*.)

"While we appreciate the work of the Pathways Launch Committee and the proposal, we did indicate that our position is neutral, and that's just because we want to be clear that we don't think that this achieves the needed independence for EDAM governance, and that needed independence is going to take legislation," Marker said.

Despite opposition, ISO staff recommended moving forward with the proposal.

"Our view at the staff level is that there is no need to make substantive changes to the Step 1 proposal as filed, and so for that reason, we are proposing to move forward with the joint meeting between the ISO Board and the Western Energy Markets Governing Body on August 13 to consider and vote on the Step 1 proposal," Schultz said.

A memorandum outlining the ISO's recommendations will be published in advance of the August meeting, though an exact date was not provided. ■

CAISO/West News

NV Energy Should Do More to Tap VPP Potential, Report Says

AEU Analysis Shows Utility's VPP Market Could Grow 9-fold by 2035

By Elaine Goodman

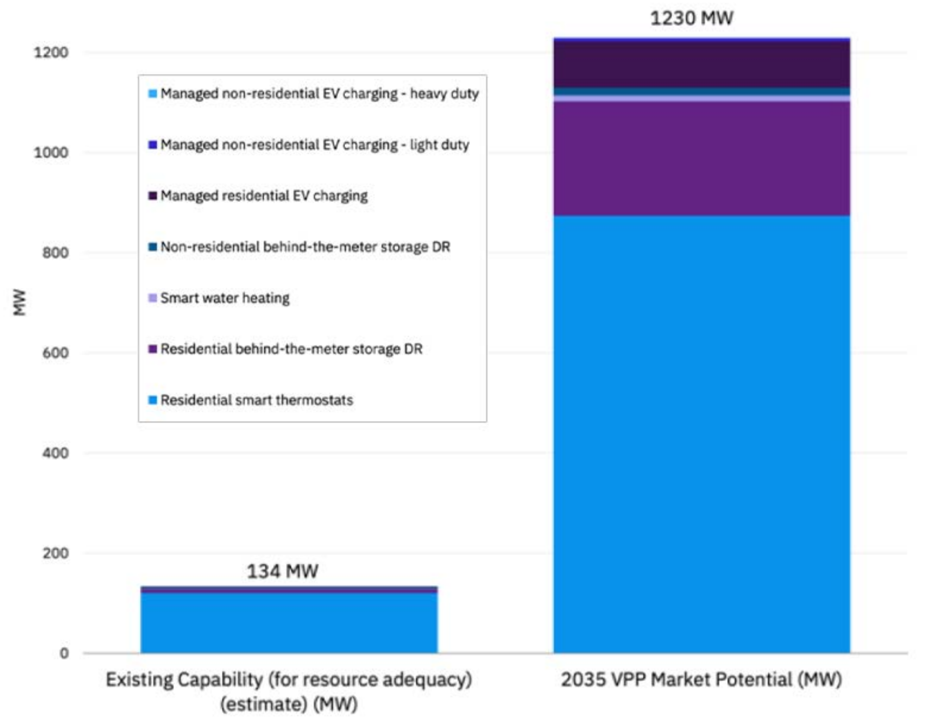
NV Energy's virtual power plant market potential could grow from an estimated 134 MW this year to 1,230 MW in 2035, according to a new analysis.

But the utility isn't taking full advantage of VPPs in its resource planning, Advanced Energy United said in the July 23 report, "*Moving the Needle on DERs and VPPs in Nevada*."

And that means a missed chance to reduce the need for new gas-fueled generation in the state, said AEU, an association representing the alternative energy industry.

In March, Nevada regulators approved NV Energy's proposal to convert its coal-fired North Valmy Generating Station to gas. And in its 2024 integrated resource plan (IRP) filed in May, the utility is seeking approval for a 411-MW gas-fired unit at North Valmy to start operating in mid-2028. The estimated cost is $573 million.

"Adding new gas instead of maximizing virtual power plant (VPP) capacity is a mistake Nevada cannot afford to make," AEU staff said in a blog post accompanying the report's release.



2035 Nevada VPP market potential | *Advanced Energy United*

VPP Benefits

In a virtual power plant, customers allow a utility or third-party firm to control their distributed energy resources in a coordinated way to provide grid benefits, such as reducing peak-hour demand.

VPPs can help utilities address resource adequacy concerns and meet decarbonization goals, proponents say. They can keep costs down for a utility, and customers who participate in VPPs receive compensation that may help offset rising utility bills.

The AEU report is the latest analysis touting the potential of VPPs.

The Brattle Group released a *report* in April for GridLab that estimated California's VPP market potential in 2035 at 7,671 MW — an amount roughly equal to 15% of peak demand. (See *Virtual Power Plants Could Save Calif. $750M a Year, Study Says*.)

A Brattle *study* for Google last year found that VPPs could provide resource adequacy at a net utility system cost that's about 40% of the net cost of a gas peaker and 60% of the net cost of a battery. (See *Brattle Group Finds VPPs Cheapest Alternative for Resource Adequacy*.)

"If VPPs are left out of resource planning as load grows and fossil fuel assets retire, Nevada runs the risk of saddling ratepayers with unnecessarily expensive sources of capacity," AEU said in its report.

'Meaningful' Compensation

NV Energy's new IRP includes a distributed resource plan and a demand-side management plan. It features a proposed "grid value" portfolio, aimed at providing "flexible resources to manage operating conditions of the power grid," the IRP states.

"It's definitely going in the right direction, but we see areas for improvement," AEU industry analyst Chloe Holden told *RTO Insider*.

AEU is concerned about the "vagueness" in NV Energy's plan, Holden said, including a lack of detail about how different devices would be treated and how customers would be compensated.

"It is essential that customers are compensated in a predictable, meaningful fashion for VPP participation and that the level of compensation drives ongoing enrollment in the VPP," AEU said in its report.

As another "best practice," AEU recommends that NV Energy invite collaboration with third-party VPP companies and allow VPP participants to bring their own devices rather than being restricted to utility-owned equipment.

Holden said AEU took a conservative approach in its estimates of VPP market potential in Nevada. The potential increases from 134 MW in 2024 to 552 MW in 2029, 750 MW in 2031 and 1,230 MW in 2035.

The figures reflect the share of DER capacity that VPP participants are expected to provide at peak times, accounting for expected customer behavior.

DERs included in AEU's analysis are smart thermostats, residential and commercial behind-the-meter battery storage, managed residential EV charging and managed commercial and public EV charging for both light- and heavy-duty vehicles.

The analysis doesn't include traditional commercial demand response.

According to AEU, the 100 highest load hours for the NV Energy grid could be moderated with 721 MW of DER capacity, which is expected to be reached by 2031. ■

CAISO/West News

Calif. Wildfire Fund Could be Model for U.S., Panelists Say

State Allows Utilities to Tap Fund to Pay Damages for Utility-caused Fires

By Elaine Goodman

A California wildfire fund created by state lawmakers in 2019 could serve as a model for a similar nationwide fund, speakers said during a webinar July 22 hosted by Americans for a Clean Energy Grid (ACEG).

Assembly Bill 1054 of 2019 established the fund, which utilities may tap into to pay claims for damages resulting from a wildfire caused by utility equipment. Money in the fund comes equally from utility ratepayers and shareholders.

Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric and Bear Valley Electric are fund participants.

The California fund is expected to grow to $21 billion. A *bill* creating a similar fund in Utah was signed into law this year.

While such a fund is possible for California, which ranks as the world's fifth-largest economy, it might not be feasible for other states, said *webinar* speaker Riaz Mohammed with the Edison Electric Institute.

"We're not sure that the financial wherewithal is there for a state-specific fund," said Mohammed, EEI's senior director of resiliency and environmental policy.

Mohammed said the institute is exploring the possibility of a national wildfire fund that would mix elements of California's AB 1054 and the Price Anderson Act, which established a fund to pay members of the public harmed by a nuclear incident.

The idea would be to create a federal fund that does not preempt any state wildfire funds, he said.

Limiting Liability

EEI is also focusing on legislation that would limit utilities' liability for wildfires.

Although inverse condemnation is a California law that views damages caused by a utility's equipment to be a "taking" of private property even when negligence isn't demonstrated, Mohammed said the concept has spread to other states.

"What we're seeing across the country is that there's really no distinction when it comes to wildfire damages or awards," he said. "Inverse condemnation is what is being applied even if that's not the law."

Courts have also been awarding punitive and pain-and-suffering damages in wildfire cases to people who have not been economically or physically harmed, according to Mohammed.

The key to a system for limiting liability would be a requirement for utilities to have a wildfire mitigation plan in place, he said. For those that do, one possibility would be sending wildfire claims to federal court, where damages would be limited, and bypassing the state courts. Mohammed said EEI is "kicking around" that idea.

Safety Certifications

Under California's AB 1054, a fire safety certification is a central element. Without the certification, utilities may still pay into the fund and access it when needed.

But when it comes time to reimburse the fund, utilities with a safety certification are presumed to have acted prudently unless regulators determine otherwise, according to Melissa Semcer, principal consultant with Climate, Wildfire and Energy (CWE) Strategies. If they acted prudently, utilities can repay with 50% ratepayer funds and 50% shareholder funds, rather than repaying solely with shareholder funds, Semcer said.

Safety certification requirements in California include having a wildfire mitigation plan, safety culture assessments and evidence of making progress on previous plans. In addition, executive compensation must be based at least 50% on safety metrics.

"That is actually a game changer," said Semcer, who was previously the deputy director of the California Office of Energy Infrastructure Safety.

Panelist Letha Tawney, a commissioner with the Oregon Public Utility Commission, said a wildfire fund raises societal issues.

"In an electric bill, you're asking ratepayers to cover rebuilding from catastrophic wildfires," she said. "Is that really what ratepayer bills should be doing?"

"And what does it mean for everyone who was still impacted by a wildfire, and it wasn't utility caused? Where are they supposed to go?" Tawney added. ■

Panelists in a recent webinar discussed different approaches for covering the costs of wildfires. | *Shutterstock*

New Western 'Regional Organization' Could be Folsom-based

'Co-location' with CAISO Among Proposals Floated by Pathways RO Formation Work Group

By Robert Mullin

The new "regional organization" (RO) envisioned by the West-Wide Governance Pathways Initiative might be based near CAISO's headquarters in Folsom, Calif., according to a straw proposal from the initiative's RO Formation and Governance Work Group.

The proposal was among a handful floated by the group during a July 25 public meeting to discuss the logistics of establishing and governing the RO, designed to assume independent authority over CAISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM) under "Step 2" of the Pathways Initiative.

Another proposal would have the RO be incorporated as a 501(c)(3) nonprofit public benefit organization (like CAISO, ISO-NE and NYISO), rather than a 501(c)4 social welfare organization (MISO, ERCOT) or 501(c)6 mutual benefit nonprofit (SPP, Western Power Pool and Western Resource Adequacy Program). PJM stands alone among RTOs/ISOs in its status as a limited liability corporation.

Work group participant Lisa Tormoen Hickey, senior regulatory attorney at Interwest Energy Alliance and member of the Pathways Launch Committee, said the work group considered how each type of corporation could serve multiple state interests and various types of utilities, and support the potential for the RO to expand its service offerings in the future to include functions such a transmission planning.

"But we mostly looked at how they would operate, employing people and renting or owning real estate and other property as necessary to be organized and operate as a viable entity in — or serving — multiple states in the West," Tormoen Hickey said.

The work group determined that a 501(c)(3) structure would provide advantages in supporting the RO's efforts in fulfilling "public purpose," while offering further nonprofit tax advantages by allowing the new organization to obtain tax-exempt financing, which reduces the costs of long-term financing and bonding.

Another proposal calls for the RO to be incorporated in Delaware because of the state's "well-developed" body of corporate law and "experienced and knowledgeable" judges and the "ease" of dealing with its secretary of state.

A new proposal calls for the new Western "RO" envisioned by the Pathways Initiative to based in Folsom, Calif. near CAISO's headquarters for operational reasons. | *© RTO Insider LLC*

"We can incorporate in any Western state, and most of them have adopted fairly standard nonprofit statutes, but they do have differences related to their amount of oversight and strict rules for formation of a board, whereas Delaware is quite flexible and considered to be a leader for corporate governance, both nonprofit and for-profit," Tormoen Hickey said. She noted that incorporating in Delaware also could avoid the political controversy of incorporating in a Western state.

"I'm completely in agreement that the body of Delaware state laws is probably the most mature for formation, and it's certainly been where most of the markets are incorporated, in terms of a legal precedent and body of laws standpoint," said committee member Scott Miller, executive director of the Western Power Trading Forum.

Question of 'Co-location'

But the work group could be courting controversy with its straw proposal to make Folsom the RO's principal place of business, even as the Pathways Initiative seeks to create an entity that operates independently of CAISO and California oversight.

"Any Western state that we choose would present a question of perception of bias and control rather than independence of that state, and we considered all of that, but we consider that to be a limited actual risk," Tormoen Hickey said.

In developing the proposal, she said, the group considered the RO's "actual center of direction control and coordination" and the location of its most "significant volume" of operations. It also factored in the extent of interaction between the RO and CAISO and the potential for sharing employees between the two.

"The RO will have its own employees; we do not yet know whether they will be few or larger in number, depending on how Step 2 [of the Pathways Initiative] shapes up," she said, referring to the outcome of the California legislation needed to release CAISO's governance from state control.

"We do want the RO to rotate its physical presence around the West. We will recommend that it [hold] meetings physically in various states around the West because that will enable stakeholder engagement and a feeling of representation within each of those states,"

CAISO/West News

Tormoen Hickey said.

"The reality is, given this step with the RO, and even if we go to [Step] 2.5, which envisions a slightly larger employment structure for the RO than [Step 2], the interaction with CAISO seems to suggest that co-locating in Folsom makes the most efficient sense, and particularly since we're building an organization that's a hybrid organization," Miller said.

Launch Committee member Connor Reiten, vice president of government affairs at Portland-based PNGC Power, said the "perception" of the RO's home base is going to be important in the Northwest, making it important for it reach out and engage in individual states.

"Putting this principal place of business wherever it makes the most sense from a legal perspective, from a recruiting perspective for the staff, all those elements, I think that's most important to focus on," Reiten said.

"Ultimately, the issue of perception from our perspective is going to be making sure that when we are interacting with the RTO, we're not feeling like we're having to go to Folsom every single time there's a board meeting or otherwise, and that these things are happening in the states that are affected by this market."

Lynn Mostoller, executive director of New Mexico's Renewable Energy Transmission Authority (RETA), cautioned the Pathways backers about using of the term "co-location" in its proposal.

That "pricked my ears because my board chair is particularly California-takeover-phobic in this whole process," Mostoller said. Avoiding the term could minimize controversy about the move, she added.

"I assume there would be completely separate offices. It would just be in the city of Folsom, not a backroom in the CAISO offices," Mostoller said.

'Working' Proposals

The work group also floated a series of "working" proposals, including:

An RO board consisting of seven members who "meet the knowledge and skills requirements" outlined in a board selection procedure. "When we looked at this, we were trying to balance making sure we had a large-enough board to ensure that we had adequate diversity — regionally, knowledge and experience to govern the market rules, but at the same time, not end up with a 20-person board or unmanageable number of board members," said committee member Jim Shetler, general manager of the Balancing Authority of Northern California.

- No board seats to be reserved based on sector, knowledge or skill. "We think that the nominating committee and the board and their selection process should have the freedom to weigh what is the right person or right set of skills and knowledge needed a particular time," Shetler said.
- A collaborative relationship between the RO and CAISO boards, with joint meetings to be held to consider issues of joint authority.
- Allowing the RO's Formation Committee to deal with details related to the transition of responsibilities from the Western Energy Markets (WEM) Governing Body to the RO board.

More complete descriptions of all proposals can be found *here* and *here*.

The group also shared a timeline for establishing the RO, which includes:

- creating a Formation Committee by December 2024;
- developing a corporate structure, drafting a tariff and bylaws, and selecting a Nominating Committee and executive search firm to select board members between January and August 2025;
- signing of California legislation to alter CAISO governance by the end of the state's 2025 legislative session, followed by a filing of tariff language with FERC and recruitment of the RO's board and executive team; and
- filing incorporation documents, seating board and hiring staff in fall 2025. ■

FERC Grants PG&E Incentives for 4 Transmission Projects

By Ayla Burnett

FERC on July 25 approved two incentives Pacific Gas and Electric requested to support work it will undertake with LS Power Grid California for four transmission projects included in CAISO's *2021/22 transmission plan* (*EL24-107*).

In an order issued at its monthly open meeting, the commission found the projects satisfy the Order 679 requirements for incentive rate treatment because they will improve reliability and reduce congestion. Commissioner Mark Christie dissented in the 2-1 vote.

FERC approved use of the Construction Work in Progress (CWIP) and the abandoned plant incentives for PG&E's supporting work to interconnect and integrate the Collinsville, Manning, Newark and Metcalf projects into CAISO's grid, which will help offset associated costs and address long lead times.

After becoming sponsor, LS Power was also awarded transmission rate incentives for the projects in March 2023.

The Collinsville Project consists of a new 500/230-kV substation, two new 230-kV transmission lines to the Pittsburg substation, looping in the Vaca Dixon/Tesla 500-kV line into the Collinsville substation and adding a series capacitor to the Collinsville/Tesla line.

The project, which is estimated to cost between $475 million and $675 million, will mitigate a constraint on the Cayetano-North Dublin 230-kV line, increasing reliability and facilitating renewable generation in the northern Bay Area, according to PG&E. It is estimated to cost PG&E $197.9 million to complete several updates, including constructing several lattice structures, new bays and line swapping, decreasing existing series capacitor banks, adding a telecommunications path and adding breakers.

The Manning project will consist of a new 500/230-kV substation and two new 230-kV transmission lines to the Tranquility substation, looping the PG&E Panoche-Tranquility transmission lines and the Los Banos-Midway and Los Banos-Gates 500-kV lines into the Manning substation. It's estimated to cost $325 million to $485 million and will mitigate the constraint on the Borden-Storey 230-kV transmission line, allowing for the advancement of renewable generation in the Westlands or San Joaquin areas, the order says. PG&E's work supporting the project will cost

A rendering of Pacific Gas and Electric and LS Power's Collinsville Project. | *LS Power*

an estimated $423.9 million for looping lines into the new substation, building new transmission lines, installing relays and switches on the Los Banos-Midway line and more.

The Newark project includes a new 500-MW HVDC line between two new LS Power convertor station facilities at an estimated cost of $325 million to $510 million. According to PG&E, the Newark project addresses CAISO's forecast of significant load increases in the Silicon Valley area that will result in overloads in the San Jose 115-kV system. PG&E's work supporting the project will cost another estimated $16.3 million and include installing a new substation bay at Newark substation, upgrading the Newark station ground grid and grading, constructing a 230-kV line with new insulators and hardware and implementing new telecommunications equipment.

Finally, the Metcalf project will consist of a new 500-MW HVDC line between the two new LS Power converting station facilities and is estimated to cost $525 million to $615 million. PG&E's work supporting the project is significant, costing $266.6 million and including constructing a 500-kV line, installing a 115-kV underground cable and expanding a portion of the Metcalf substation.

'Check-the-box'

PG&E argued that the CWIP incentive will help support the significant cost of the projects, which are projected at $904.7 million between 2024 and 2028 — a "significant portion of PG&E's planned $9.1 billion in overall transmission spending during that period," the order reads.

The incentive would also help address the long lead time between 2024 and 2027/28, which is the earliest the projects are expected to go into service.

"PG&E contends that requiring investors to wait a minimum of four years before receiving a return on their investments would diminish the attractiveness of these investments relative to other PG&E investments that have shorter lead times. Further, PG&E argues that allowing CWIP recovery will lower financing costs, which will decrease the total revenues paid by consumers over the life of the projects," the order reads.

CWIP recovery would also reduce the "rate shock" that could occur if the cost of the projects were only accounted for in the 2028/29 rate case.

But in a protest submitted to FERC, the California Public Utilities Commission argued that the CWIP incentive is harmful to California ratepayers by requiring "premature and excessive rate recovery." When projects have longer lead times and higher costs than when forecasted at the time the incentive was granted, the incentives cost consumers more and provide a one-sided benefit, the CPUC said.

If FERC granted the incentives, it should put up "guard rails," the CPUC argued, including capping CWIP eligibility at the cost of the project and rescinding CWIP recovery as soon as CAISO's original in-service date passes.

Maintaining course with past dissent, Commissioner Christie also argued that PG&E should not be awarded the CWIP and Abandoned Plant incentives.

"The CWIP and Abandoned Plant incentives are nothing more than a transfer of wealth from consumers to transmission developers and risk from developers to consumers," Christie said in his dissent. "It is long past time for the commission to revisit its 'check-the-box' practice of granting transmission incentives, including as set forth in Order No. 679. The longer the commission does nothing to address these unfair transfers of wealth and risk, the more consumers are exploited."

But FERC sided with PG&E in granting both incentives for all four projects without 'guard rails.'

"We find that PG&E has demonstrated that each of the requested incentives, and the package as a whole, address its risks and challenges for the support work that it will undertake in conjunction with the projects," the order said. ■

ERCOT News

CenterPoint CEO Promises PUC Utility Will 'Improve'

By Tom Kleckner

CenterPoint Energy executives appeared before Texas regulators July 25 to apologize for the company's slow restoration following Hurricane Beryl's landfall and promised to do better next time.

The Houston utility had 2.6 million customers without electricity in the storm's immediate aftermath, with some waiting more than a week to get their power back. CenterPoint was roundly criticized for the slow response and its poor communications with customers.

"In times of emergency, our responsibility is to respond quickly, to communicate clearly, to provide accurate information and to restore power as rapidly and safely as we can," CenterPoint CEO Jason Wells told the Public Utility Commission during its open meeting.

"I take personal accountability on areas where we fell short of our customers' expectations," he continued. "Most importantly, I want to apologize. While we cannot erase the frustrations and difficulties so many of our customers endured, I, my entire leadership team, will not make excuses. We will improve and act with a sense of urgency."

Wells said CenterPoint will begin immediately to improve its communication with customers as part of an *action plan* with two other "pillars of action" focused on resiliency and greater collaboration with local partners and emergency responders. The intent is to address issues for the remainder of the hurricane season and beyond.

Central to the plan is strengthening the utility's vegetation management efforts. Wells said that as of July 16, CenterPoint had nearly doubled its vegetation-management workforce "to immediately address the higher risk areas ... throughout the rest of this calendar year."

The utility plans to roll out a new cloud-based outage tracker Aug. 1, replacing the previous version that never was able to recover after being swamped following a derecho in May. It also will use composite poles to replace about 1,000 distribution poles currently planned for 2024.

New utility poles line right-of-way amid the storm's debris in Conroe. | *© RTO Insider LLC*

CenterPoint said its crews removed or trimmed more than 35,000 trees during the restoration effort, walked over 8,500 to repair damage and replaced more than 3,000 poles.

Wells said CenterPoint will hire a new senior executive team member with expertise in emergency and storm response. More actions will be taken based on internal reviews, independent analysis and counsel from emergency response and communications experts, and feedback from the PUC, elected officials and community leaders, and its customers.

"Going forward, our most important priority today and in the months ahead will be to improve our emergency response with a sense of urgency to re-earn your trust and the trust of the millions of people who depend on us," Wells said.

The PUC has opened a "rigorous" study of CenterPoint over repeated failures in its footprint. The utility also is being probed by state lawmakers, with hearings scheduled July 29 and July 31. (See related story, *CenterPoint Under Fire for Its Beryl Response*.)

The commission threatened to recall CenterPoint's $2.3 billion resiliency plan — filed in April and currently in settlement negotiations — and preside over the hearings. However, it agreed to give the utility time to reach an agreement with the other parties (*56548*).

"I want to ensure that we have the right, as in the law, to modify any plan that's presented to us," Commissioner Jimmy Glotfelty said. "Even if there's a settlement, we must be willing to bring this back to the commission to get deeper into the specifics of how we will ensure resiliency on the CenterPoint system."

"You have an obligation to serve. You have an obligation to provide continuous and adequate service," fellow Commissioner Lori Cobos said. "Getting a resiliency plan approved does not stop you from doing what you should be doing already to maintain continuous and adequate service for your customers and your service territory."

CenterPoint promised the PUC it would provide an update on the settlement negotiations within a week. ■

ERCOT News

CenterPoint Under Fire for Beryl Response

Texas Legislature, Regulators Probing the Utility's Actions

By Tom Kleckner

Beleaguered Texas utility CenterPoint Energy has come under fire from the state's political leadership, lawmakers, regulators and residents over its slow restoration efforts following a Category 1 hurricane.

The heat is only intensifying.

Gov. Greg Abbott (R) has *ordered* CenterPoint to file a plan with his office by July 31 that outlines how the utility will improve its preparation and response practices before the next hurricane hits. If CenterPoint fails to comply, he threatened to oppose any future rate increases brought to the Public Utility Commission, whose members he appoints.

"CenterPoint Energy has lost the faith and trust of Texans. ... Texans deserve better from their electrical companies," Abbott wrote in a letter to company CEO Jason Wells.

Abbott also *directed* the PUC to conduct a "rigorous" study to determine the causes of "repeated and ongoing power failures" in the Houston area after severe weather events. A mid-May derecho knocked out power to more than 1 million CenterPoint customers, some for as long as 17 days.

The governor asked the PUC to determine whether the large customer outages are a result of a physical infrastructure or personnel issue. Abbott said the commission must identify why Hurricane Beryl affected millions of Texans when similar events in the recent past did not and file a report to the state legislature by Dec. 1 (*56822*).

"I think it's clear from the events of the past week that the quality of their infrastructure, their ability to maintain that infrastructure and their communication with their customers has been called into question," PUC Chair Thomas Gleeson said during a July 14 news conference.

Lt. Gov. Dan Patrick (R), who said CenterPoint "underestimated" Beryl's force and direction, *created* a special committee in the state Senate on hurricane and tropical storm preparedness, recovery and electricity. The committee, charged with reviewing "certain utility companies'" response and establishing why they "appear to have been woefully unprepared for Hurricane Beryl," will hold its *first hearing* July 29.

The state House will join the inquisition two days later when its State Affairs Committee conducts an *oversight hearing* on recent electric industry legislation. It has added an agenda item assessing "utility preparedness, response and recovery protocols" and reviewing performance during severe weather events.

When Beryl barreled ashore July 8, it left 2.7 million people without power. (See *Hurricane Beryl Leaves 2.7M Customers Without Power*.)

As of July 23, more than 1,600 CenterPoint customers were without service. The utility said it had restored almost 73,000 customers in the previous 24 hours, although not all outages stemmed from Beryl. CenterPoint has not issued a public update since July 17, when it said power to 98% of customers had been restored.

In an email to *RTO Insider*, CenterPoint said it has restored power to all customers "who are able to receive power." It said remaining outages are "predominantly isolated instances" in which severe home damage or damage to customer-owned equipment has made restoration difficult.

Entergy Texas, which lost power to more than 252,000 customers when Beryl hit July 8, said July 16 that it expected to restore electricity to all its customers who could safely take power. Its outage count was less than 600 on July 23, according to *PowerOutage.us*.

It is CenterPoint that has drawn much of the ire from Houston residents. *Half of the 22 deaths* caused by the storm have been attributed to slow restoration efforts and triple-digit temperatures.

Houston Mayor John Whitmire (D) has threatened to hold CenterPoint accountable by documenting the trouble it has given City Hall.

"I'm pretty fired up at them. They made my job tougher by not doing their job," Whitmire told the *Houston Chronicle*.

CenterPoint's shortcomings will provide plenty of fodder for those investigating the utility.

It was ridiculed nationally for an *outage map that was less reliable* than a hamburger chain's app and it has been criticized for its lack of preparation before the storm. Utility representatives told the PUC during a July 11 open meeting they were surprised by the damage Beryl caused in the heavily wooded areas north and east of Houston. (See *Texas Utilities: Beryl's Damage Unlike that of Cat 1s*.)

CenterPoint Energy CEO Jason Wells (second from right) and other senior executives brief the Texas PUC on their Hurricane Beryl response. | *Admin Monitor*

CenterPoint has spent more than $800 million in recent years on 15 32-MW generators and five smaller ones. However, the 15 massive generators are not designed to be mobile and *were never used during the storm*.

The utility has also come under fire for poor tree trimming and maintenance and its poor communication from the top down. Wells filmed a message to Houstonians from an office setting during which he mentioned he had a generator at home, all while sitting next to a thermostat that read 70 degrees.

In April, CenterPoint filed a *$2.3 billion resiliency plan* as a result of 2023 legislation. The Texas Consumer Association has asked that the *plan be delayed* until the probes into the utility have concluded. CenterPoint has already estimated repairing the derecho's damage will cost about $475 million.

Separately, Entergy has filed a rate increase with the PUC to recover $6 billion in infrastructure investments since 2019.

The heat continues to build. ■

ERCOT News

Texas Commission Rejects ECRS Rule Change

PUC Tosses Offer Floor, Keeps Trigger Mechanism

By Tom Kleckner

Texas regulators have rejected an ERCOT protocol change that took months of sometimes-contentious negotiations before the grid operator's staff and stakeholders could reach a compromise that earned board approval.

In taking up the rule change (*NPRR 1224*) that modified the ISO's new ERCOT contingency reserve service (ECRS) product, the Public Utility Commission removed a proposed $750/MWh pricing floor. It also asked ERCOT to separately implement the revision's trigger mechanism for the service (*54445*).

The commission sided with *staff's determination* that the operating reserve demand curve (ORDC), which uses scarcity pricing to value operating reserves, should be relied upon to generate "economically appropriate market pricing." Staff said the offer floor "inappropriately supplants the role of the ORDC in pricing scarcity risk" and said the demand curve should remain the vehicle to price ECRS capacity and deployment risk until real-time co-optimization can be deployed.

The ISO plans to add co-optimization of energy and ancillary services in real time in 2026.

ERCOT COO Woody Rickerson said NPRR 1224 was originally drafted without an offer floor. It was expected, he said, "but we wanted to get market participant feedback on what the offer floor would be ... the NPRR was written so that that offer floor can be filled in after market participant input."

"I thought you all were completely agnostic to that, to be honest," PUC Chair Thomas Gleeson said. "Is it still fair to say that the part of this revision that is most important to ERCOT is the trigger?"

"Yes," Rickerson responded. "ECRS is a high-need reliability tool."

The trigger mechanism takes effect when there is a 40-MW power balance violation for at least 10 minutes.

The rule change was approved by ERCOT's Board of Directors in June and included the offer floor and trigger mechanism for the ancillary service product. ECRS procures capacity resources that can be brought online within 10 minutes and sustained at a specified level for two consecutive hours. (See "Contentious NPRR Revising ECRS Passes over Monitor's Objections," *ERCOT Board of Directors Briefs: June 17-18, 2024*.)

ERCOT COO Woody Rickerson (left) listens to Potomac Economics' David Patton during their comments to Texas PUC. | *Admin Monitor*

ERCOT's Independent Market Monitor has opposed ECRS after it first was deployed in June 2023. It says the grid operator's first new ancillary service in 20 years created artificial supply shortages that produced "massive" inefficient market costs totaling more than $12 billion in 2023. (See *ERCOT Board of Directors Briefs: Dec. 19, 2023*.)

Potomac Economics' David Patton, whose firm serves as ERCOT's IMM, again pressed his case against the protocol change. He made his third business trip to Texas in eight months to *argue against* the NPRR.

"The market performance that was impacted by the deployment of ECRS in 2023 was calamitous. I've never seen something as bad as what happened," Patton told the PUC. "The priority has to be to fix ECRS, not just iterate and improve and make it a little bit better. We know how to fix this. What the NPRR would do is institutionalize a fairly large share of the dysfunction that we saw in 2023."

Patton told *RTO Insider* the PUC's decision was a "partial victory."

"The trigger mechanism, while it may be used in the near term, can be changed and improved by ERCOT if I can convince them that it is having unintended consequences. If the protocol revision had passed, we would be stuck with it," he said in an email. "Ultimately, that decision had huge cost implications over the next two years."

Attorney Katie Coleman, who represents the Texas Industrial Energy Consumers lobbying group, agreed with the commission's decision to remove the offer floor and allow ERCOT to address the deployment trigger. She called for a $100 floor during the board's discussion.

Coleman also agreed with Gleeson's complaint that ERCOT's board process "did not work"

ERCOT News

for him. Gleeson said he and Commissioner Lori Cobos, who both sit on the grid operator's board, did not comment during the directors' consideration of NPRR 1224 because they did not have all the information they needed.

"I would argue that some of the most pertinent information I heard came in post-board decision. ... I need to have all the information that I can have at the board because I think it is important for me to be able to tell the board what I think so that if they pass something, they know perhaps it may get rejected at the PUC. For me, that does a disservice to the board process," he said.

"Unfortunately, there was urgency to move something through the stakeholder process to try to get it implemented this summer, and as a result, some of the issues and analyses were not fully fleshed out before the board," Coleman told *RTO Insider*. "We agree with [Chair] Gleeson that improvements are needed to make sure the board has all the information needed to make the right decision."

SPS Capacity Needs Partly Approved

The commission partly granted Southwestern Public Service's request for additional capacity to meet SPP's planning reserve requirement (PRM), approving three solar farms but rejecting a battery storage facility (*55255*).

An administrative law judge in May *approved* SPS's application for three solar facilities at existing plant sites in Texas and New Mexico offering 418 MW of nameplate capacity. However, the ALJ rejected a request for a 36-MW battery facility in New Mexico, saying SPS has failed to prove the facility is an economical solution to its capacity needs because it would add only an incremental amount of capacity relative to its $66 million cost.

Gleeson filed a *memo* agreeing with much of the ALJ's decision. He found fault with the conclusions that SPS "adequately considered" alternatives to the solar facilities and that its request-for-proposals process was conducted reasonably. Gleeson recommended adding a cost cap to the solar facilities, currently projected at just over $700 million, and agreed with the ALJ's recommendation for a third-party review if the construction costs are 10% greater than projections.

The PUC chair wrote that SPS's "questionable" resource planning decisions placed the commission in a "difficult position."

"I believe a cost cap may be appropriate in this case because of SPS's failure to adequately consider alternatives, which led them to the selection of a capital-intensive, non-dispatchable resource to satisfy their capacity needs," Gleeson said.

SPS filed in July 2023 to increase its capacity needs following SPP's three-point increase in the summer PRM to 15%. The utility said the additional capacity would be needed as early as 2024 due to the retirement of aging natural gas facilities, the expiration of power purchase agreements, and projected customer load growth. (*See SPP Board, Regulators Side with Staff over Reserve Margin*.)

The commissioners agreed SPS should ensure customers receive 100% of the solar facilities' production tax credits as they are earned.

Staff Begins Beryl Investigation

PUC staff has filed a *memo* outlining a proposed scope and approach to the commission's investigation of Houston utilities' response to Hurricane Beryl (*56822*).

Staff is planning to send requests for information to electric and water service providers in the Greater Houston area and to invite generation companies, retail electric providers and communications service providers to submit the effects to their services and their response to the May derecho event and Beryl.

They also are analyzing utilities' emergency operations plans, vegetation management plans, infrastructure and storm hardening plans, after-action reports, and customer complaints. Their investigation will include reviews of storm preparedness and response best practices from infrastructure experts.

A draft report is scheduled to be presented to the commission for its consideration during the Nov. 21 open meeting. A final report will be delivered to Texas Gov. Greg Abbott (R) and the state Legislature by Dec. 1. ■

ISO-NE News

FERC Ends Section 206 Proceeding for New Brunswick Energy Marketing

By Jon Lamson

| © RTO Insider LLC

FERC ruled July 25 that New Brunswick Energy Marketing does not appear to have horizontal market power in the New Brunswick (NB) balancing authority area, concluding a Section 206 proceeding that came out of a failed market share screening test (*ER14-225-008, et al.*).

The NB balancing authority includes parts of Northern Maine and Eastern Canada. NB Energy Marketing is a subsidiary of the crown corporation NB Power and is directly interconnected to the transmission systems of ISO-NE and the Northern Maine Independent System Administrator.

ISO-NE initiated a Section 206 proceeding after NB Energy Marketing failed a "wholesale market share indicative screen" in three of the four seasons in the 2020/21 study period, suggesting the presence of *horizontal market power*.

The proceeding aimed "to determine whether NB Energy Marketing's market-based rate authority in the New Brunswick balancing authority area remains just and reasonable." (See *FERC Orders Section 206 Proceeding for New Brunswick Energy Marketing*.)

Responding to FERC's show cause order on horizontal market power, NB Energy Marketing made the case that the results of a delivered price test (DPT) and a sensitivity analysis indicate the company is not a pivotal supplier.

When accounting for NB Power's capacity factors and average load, the company "has a market share generally less than 20% and does not contribute significantly to market concentration," NB Energy Marketing wrote in its filing.

Based on this evidence, FERC terminated the Section 206 proceeding, concluding that "on balance, NB Energy Marketing has successfully rebutted the presumption of horizontal market power in the New Brunswick balancing authority area." ■

MISO News

MISO Sets Sights on 50% Peak MW Cap in Annual Interconnection Queue Cycles

By Amanda Durish Cook

MISO said it plans to pursue a more straightforward, 50% peak load megawatt cap to limit the number of generator interconnection requests it would accept annually.

At MISO's July 23 Interconnection Process Working Group teleconference, the grid operator revealed the cap would be based on 50% of peak load per study region. MISO divides its footprint into West, Central, East and South regions for queue study purposes.

MISO Manager of Generation Interconnection Ryan Westphal said using 2022 study modeling, a queue cap would have been about 68 GW. He said the simpler cap would take MISO's future resource adequacy need into account as FERC recommended, though he didn't offer specifics.

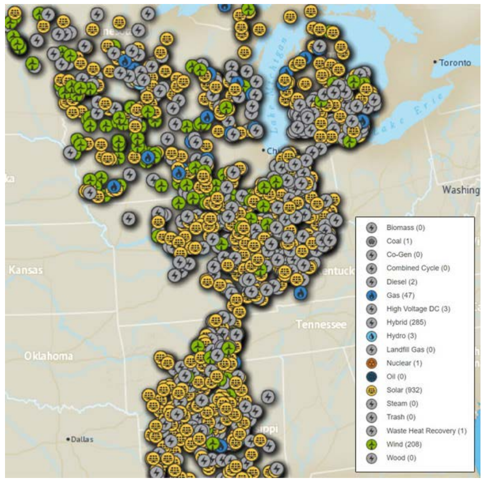
MISO attempted last year to enforce an annual megawatt cap on its interconnection queue. FERC rejected the attempt on concerns over too many cap exemptions, the formula to establish the cap and potential resource adequacy deficits stemming from limiting new generation onto the grid. (See *MISO: New Interconnection Queue Cycle to Wait on MW Cap Filing*.)

MISO's original cap formula was intended to be rooted in its ability to develop a reasonable dispatch for studying interconnection requests based on the existing system and considering regional and subregional peak loads. The complex calculation involved landing on load remaining to be served after existing generation and higher-queued generation proposals are dispatched at the lowest possible megawatt output while remaining online.

Westphal said MISO hopes to submit a fresh FERC filing for a more uncomplicated cap before the end of the year.

NextEra Energy's Erin Murphy asked how MISO arrived at the 50% value. Westphal said MISO assessed its rounds of potential generation submittals prior to the 2022 "explosion" of queue requests. He said before the exponential growth, MISO was processing about 60-GW entry classes. MISO is processing 123 GW of queue hopefuls that lined up in the 2023 *cycle*. If all projects proceed, MISO could have a more than 300-GW queue on its hands.

Westphal said MISO doesn't have a "specific date" for when it will close the current queue cycle. MISO's application portal is open for interconnection customers to submit projects for MISO to review application completeness. However, MISO is holding off on processing the queue in earnest until it secures FERC permission to administer a cap.



MISO's crowded online map of active interconnection projects as of July | *MISO*

Stakeholders asked whether projects that don't make the cutoff would have priority access to MISO's next queue cycle. Westphal said any projects shut out of a queue cycle would be "first in line" for the subsequent cycle.

MISO also said a few projects put forward after the cap is reached might be selected to proceed if other projects don't successfully clear MISO's validation process.

MISO staff said the grid operator would use the timestamps on project submittals to determine their place in line. Westphal said MISO wouldn't refund study deposits to developers that don't make the cap cutoff but hold on to them to prepare for processing them during the next queue cycle.

Derek Sunderman, of Shell subsidiary Savion, said MISO's proposal doesn't seem to address late-stage project withdrawals. He also said the cap won't encourage developers to only put their most promising projects forward and not "hammer" the queue with several projects to secure a position.

Westphal said MISO is open to use of a *volumetric price escalation* in addition to the cap, where interconnection customers' fees and penalties rise as they submit more projects to the queue for study. He said MISO is considering starting at $8,000/MW for the first milestone fee.

Last month, Savion suggested MISO enact escalating financial commitments to prevent a handful of interconnection customers from submitting a disproportionate number of applications. MISO said raising fees based on a corporation's project count would introduce several new requirements.

MISO once again proposes exemptions to the cap, though not as many as in its first filing with FERC. Westphal said MISO would exempt generators with provisional generator interconnection agreements; generators seeking to replace retiring counterparts and in need of extra interconnection service; and those generators wanting to convert their unguaranteed energy resource interconnection service with the higher-quality network resource interconnection service.

MISO again plans to exempt generation singled out as necessary by state commissions, though it would limit those exemptions from an unlimited number to three apiece annually per regulatory body.

Bill Booth, a consultant to the Mississippi Public Service Commission, questioned MISO's three-project limit on regulator-backed projects. Booth said the restriction doesn't make sense if MISO's goal is to cut down on speculative projects. He said a project backed by regulators usually is a sure thing.

Westphal said MISO needs some kind of limit in place, per FERC's 2023 rejection of the first cap.

"FERC basically said without some kind of limit, we undermine the cap. We need to put some kind of limit on here based on what we heard from FERC," he said.

Westphal said the cap is essential to make interconnection studies more manageable. He said as more projects vie for entry, more upgrades become necessary, and the more complex and insurmountable studies become.

"The point of the cap is to speed up the queue," Westphal said.

Murphy asked what MISO is doing beyond proposing a future queue cap to address the backlog of projects now.

Westphal said MISO will build more automation into the 2023 modeling. The grid operator has solicited help from Pearl Street Technologies to determine whether their software can speed up interconnection studies. ■

MISO News

FERC Requires More Intel on MISO's New Capacity Accreditation Method

By Amanda Durish Cook

FERC said it needs more explanation behind MISO's plan to accredit resources based on a combination of their projected availability and historical performance during periods of high system risk.

The commission handed MISO a deficiency letter July 25 concerning several aspects of its proposed direct loss of load capacity accreditation method and gave it 30 days to respond (*ER24-1638*).

Under the proposed method, generators' capacity credits would be determined by a two-step process that marries historical performance of individual generators with a probabilistic performance during simulated loss-of-load events. (See *MISO: New Capacity Accreditation Filing Imminent*.)

First, MISO would calculate a probabilistic, resource-class average accreditation using its loss-of-load modeling. It would tailor resource class-level accreditations to individual generators based on their availability during both normal operating conditions and high-risk hours, including hours containing low margins or hours with an emergency event in place. MISO plans to give greater weight to hours that contain emergency or near-emergency conditions in the ensuing accreditation.

Most resources' credited capacity would shrink under the new method. Resources would be divided by fuel type: gas, coal, hydro, nuclear, energy storage, pumped storage, wind and solar. MISO said the new process would satisfy both a prospective and retrospective approach to accreditation and wants it in place for the 2028/29 planning year.

But FERC wanted to know if MISO would consider deliverability limits in either the individual or resource-class level accreditation calculations. It asked whether a resource is required to obtain full deliverability rights to receive the maximum capacity accreditation and asked if the accreditation would differentiate between resources interconnected at MISO's basic, unguaranteed energy resource interconnection service or the higher-quality, firm network resource interconnection service.

MISO control room | *MISO*

FERC was also interested in how the 1,950-hour limit that MISO intends to use in its probabilistic model for high-risk hours would help it take the best measure of resource availability.

MISO proposed to gauge resource availability using the riskiest 65 hours, or 3% of a season, across 30 weather years in its loss-of-load modeling. The 1,950 hours include all the times when loss of load occurs and then draw on hours when available generation comes within 3% of load or less.

However, that limit does not kick in if MISO's modeling shows more than 1,950 hours when loss of load occurs. The RTO said it did not want to "dilute" real loss-of-load risk in its accreditation.

FERC asked how MISO would factor load forecast error and effective margin into the weighting calculation for risky hours to capture future uncertainty.

The RTO should also explain how it will model and dispatch storage with the new method, FERC said, pointing out that stakeholders had asked it to delay the filing of the proposal until it can improve its loss-of-load modeling of storage.

FERC said MISO needs to justify its strategy to use resources' planned outages to decrease the capacity availability of resource classes in its probabilistic model. It pointed out that the RTO currently allows exemptions for planned outages in its accreditation.

The commission asked after MISO's criteria for establishing resource classes, including the operating characteristics and any quantitative thresholds it looks for to sort resources.

And FERC questioned MISO placing oil, gas and dual-fuel resources in the same resource class. It asked MISO if there was a minimum number of megawatts or individual resources it requires before forming a new resource class. The commission appeared to suggest that it perceived operating differences between dual-fuel, oil and gas resources.

Finally, the commission was interested in knowing more about how MISO would handle instances when a market participant disputes the class their resource is categorized into. It also requested MISO's final deadline for making resource-class level accreditation calculations in the event that resource classes change by more than 3% and at least 30 MW. ■

MISO News

NRDC: Coal Plants Squeezing Out Cheaper Resources in MISO Market

By Amanda Durish Cook

Coal plants in the Central U.S. are elbowing out lower-cost, cleaner generation and have collected more than $1 billion in uneconomic payments over a three-year span, the Natural Resources Defense Council said in a new report.

NRDC secured Grid Strategies to conduct the report: "*The Consumer and Environmental Costs from Uneconomically Dispatching Coal Plants in MISO,*" which concluded uneconomic dispatch of coal plants remains a problem in MISO, where coal plants operate even when inexpensive wind and solar generation is available through self-commitment, self-scheduling and unrealistic market bids.

The report found that coal plants collected about $1.1 billion in uneconomic payments from 2021 to 2023 and forced 3.8 million MWh of renewable generation curtailment while emitting 5.2 million short tons of avoidable carbon pollution.

According to the report, coal plants in MISO are operating for extended periods when their marginal costs are run at a loss for extended periods of time while "crowding out cleaner, cheaper resources."

NRDC said the problem was the starkest in Louisiana and Indiana, which accounted for $341 million and $338 million in economic losses, respectively. The report also called out North Dakota, where coal plants realized $120 million in unjustified payments from 2021 to 2023. Otherwise, the report found that coal generators in MISO states took in anywhere from $2 million to $69 million in uncompetitive payments.

NRDC said the worst offenders included Cleco's Big Cajun II in Louisiana, Duke's Gibson Generating Station in Indiana and NIPSCO's R.M. Schahfer Generating Station in Indiana.

North Dakota was host to the most renewable energy curtailment to accommodate uneconomic coal generation, NRDC said, at 1,516 GWh in curtailments over the three-year period. Two other wind-rich states rounded out the most renewable curtailments: Iowa at 755 GWh and South Dakota at 671 GWh.

"Customers shouldn't have to pay higher bills to keep dirtier, more expensive coal plants online," Dana Ammann, policy analyst at the Sustainable FERC Project at NRDC, said in a press release. "Grid operators need to stop this inefficient practice and make these plants compete on a level playing field."

NRDC said MISO should clamp down on coal operators' "ability to supply power to the grid more or less at their own discretion — regardless of cost or rules." The organization said power markets have an obligation to ensure the cheapest resources are run first.

NRDC recommended MISO resolve to decommit uneconomic generators, move to a probabilistic unit commitment system, design voluntary multi-day markets or look-ahead tools and work to ensure the accuracy between generator bids and units' actual operating parameters. FERC also could "act on the basis that conventional generator self-scheduling and self-commitment result in undue discrimination against renewable resources," NRDC said.

The organization further said state commissions should stop utilities from recovering uneconomic dispatch in costs and review fuel supply contracts to "ensure they do not perversely incentivize uneconomic dispatch."

"When uneconomic coal plants displace wind and solar power, it sends a signal to reduce future development of those projects. Coal plant operators shouldn't get a bailout from customers," Ammann said.

MISO has not yet responded to a request for comment. ■

Gibson Generating Station in Owensville, Ind. | *United Steel Structures Inc.*

MISO Previews Future Projects to Improve System Planning

Updates to Processes for HVDC Interconnection, Expedited Projects, Co-located Load

By Amanda Durish Cook

MISO has multiple planning topics to tackle on the horizon, with work involving an update of merchant HVDC interconnection procedures, making expedited transmission project reviews more manageable, and evaluating co-located load and generation seeking interconnection.

The RTO discussed the trio of subjects with stakeholders during an Interconnection Process Working Group (IPWG) teleconference July 23 and a Planning Subcommittee teleconference July 24.

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Every-other-month Expedited Projects

MISO said it hopes to pivot to a bimonthly processing approach for transmission projects submitted by members for expedited treatment.

During the PSC call, Senior Expansion Planning Engineer Amanda Schiro said MISO wants to kick off an expedited project request window every other month. Schiro said the RTO needs more structure in the process, and an every-other-month schedule to study requests for system impacts would help it internally manage the increased volume of out-of-cycle projects.

Currently, MISO processes requests for projects that cannot wait until end-of-the-year approval through the annual Transmission Expansion Plan (MTEP) as they are received. The RTO originally hoped to roll out a quarterly expedited process but was met with stakeholder resistance. (See *MISO Starting from Scratch on New Schedule for Reviewing Expedited Tx Projects*.)

A bimonthly process would allow MISO to better manage its workload and the unpredictable nature of expedited project requests, Schiro said. She said members would be free to submit their expedited projects at any time.

"We understand that loads pop up at any time, so we do still want to have an on-demand submittal," Schiro said.

MISO plans to study smaller expedited projects in batches while larger, complicated projects will get individual assessments. Schiro said MISO recognizes that different expedited requests will require different timelines for review, adding that the RTO has taken about 100 days to study some of its larger expedited projects.

Schiro said MISO intends to remove the requirement that projects necessitated by state departments of transportation need to enter the expedited process. She said such requests tend to be minor and often involve relocating a line to the other side of a highway. Those projects would be routed instead to MISO's MTEP portal, where the RTO will check them over and allow them to proceed.

MISO also wants fewer dedicated technical study task force meetings, where expedited project reviews are discussed. Schiro said it is burdensome to compile materials and plan meetings, and the RTO wants the meetings to similarly transition to an every-other-month cadence for staff to discuss groupings of projects.

The RTO said that when it first developed its expedited process, it fielded about four to six additional studies per MTEP cycle, with project approvals allowing quick funding for immediate reliability needs. Over the past three years, however, MISO said larger, more complex load additions with quick turnaround times have become the main reason for growing expedited treatment requests. MISO this year is expecting at least 30 expedited requests.

Invenergy Seeks Changes to HVDC Connection Procedures

Having submitted its Grain Belt Express for interconnection to the MISO system, Invenergy has approached MISO with ideas to improve its process for incorporating merchant HVDC.

Invenergy's Arash Ghodsian told the IPWG that as Grain Belt has become the first to navigate MISO's interconnection process, it has "come across a number of areas for improvement."

Merchant HVDC lines that want to connect to the MISO system must follow *Attachment GGG* of the tariff to gain injection rights. The process looks familiar to the RTO's interconnection process: Developers must pay study deposits, submit to studies and agree to pay for network upgrades if necessary.

However, Ghodsian said MISO's HVDC interconnection procedures do not include a provision that allows an HVDC developer to utilize

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its connection to the grid before all network upgrades are complete. The RTO allows such limited operations for projects in its generator interconnection queue.

Ghodsian said Invenergy hopes MISO and stakeholders will discuss that recommendation and other areas for improvement at upcoming IPWG meetings.

Grain Belt Express struck an effective transmission connection agreement with MISO in February.

NextEra Makes 2nd Overture for Bundled Studies

MISO and stakeholders will likely consider a dedicated study and registration process for new generation contingent on large loads in the months ahead.

NextEra Energy's Erin Murphy again said her company and others want MISO to create a designated market participation and registration for co-located load and generation behind the same point of interconnection. (See "NextEra Asks MISO to Study New Load and Generation Duos," *MISO Starting from Scratch on New Schedule for Reviewing Expedited Tx Projects*.)

During the PSC teleconference, Murphy said MISO currently has a "disconnect" between the load growth studies completed under annual MTEPs and its studies for new generation through its interconnection queue. She asked MISO to "harmonize" how it considers generation contractually dependent on new load to be "poised and ready" for the rise of data centers.

NextEra has suggested the connected studies should be reserved for "hyperscale loads" and that MISO could institute a minimum size requirement to consider the studies simultaneously. The RTO could also make generation interconnection agreements conditional on the new loads, Murphy said.

Evaluating load and generation together in some cases will result in more efficient and economical study results, she argued. NextEra is looking to collaborate with stakeholders to bring a recommendation on how to best connect load studies to their dedicated generation.

Coalition of Midwest Power Producers' Travis Stewart said NextEra's idea is imperative to reflect the new load growth reality in the footprint.

"Large loads are popping up all over the country, and this would bring MISO in lockstep with other regions," Stewart said.

Other stakeholders said they worried that load-dependent generation studies would complicate a queue process that MISO is currently trying to streamline. They said load might need to put up securities to mitigate queue restudy costs.

Murphy said the goal of the proposal is to provide more certainty in the interconnection process, not elicit more restudies. She also said MISO could place some parameters on how far generation can be sited from the load before they are no longer considered in tandem. ■

DC Circuit Declines Entergy Challenge of MISO Seasonal Accreditation

By Amanda Durish Cook

The D.C. Circuit Court of Appeals rejected Entergy's challenge of MISO's seasonal capacity accreditation and generator outage rules, two years after FERC approved the rules.

The court in a July 26 order decided FERC adequately explained why it allowed the new capacity accreditation and denied Entergy's petition for review (*22-1335*).

Entergy argued that MISO's new capacity accreditation would result in volatile and fluctuating capacity scores and that MISO's seasonal outage rules for generators were burdensome.

MISO's capacity accreditation assigns values based on resources' performance over the past three years. The accreditation calculation gives a heftier, 80% weight to the 65 hours in a year when supply is the tightest and gives all other hours in a year a 20% weight.

Entergy contended MISO's method over-relied on just 65 hours, and a generator's accreditation could be tremendously affected if a planned outage happened to occur during some of the riskiest 65 hours. The company made similar arguments when requesting a rehearing of FERC's 2022 approval. (See *Regulators, LSEs Ask FERC to Reconsider MISO's Seasonal Capacity Accreditation*.)

But the D.C. Circuit decided FERC appropriately evaluated the accreditation style using a MISO-created analysis that compared existing and proposed accreditation methods to actual resource availability over 11 days containing emergency conditions in 2021. MISO found its old methodology overestimated resources' offerings anywhere from 8 to 22%, while its new process was off by just 1%.

The court said FERC was correct to assume MISO's new accreditation would be "more accurate than its prior approach when predicting resource performance during periods of highest demand."

Entergy argued MISO's 11-day sample size was too small. But the court said its hands were tied on considering MISO's sample size because Entergy didn't specifically raise that concern in its rehearing request with FERC. The court cited the Federal Power Act's "unusually strict" exhaustion requirement.

The court also noted MISO uses a three-year rolling average when taking stock of a resource's availability for accreditation, reducing year-to-year accreditation volatility.

Entergy Louisiana's J. Wayne Leonard Power Station near New Orleans | *Entergy*

"If bad luck besets a resource one year, the impact of such bad luck is blunted by the fact that other years can help balance out an anomalous season," the court said.

The court didn't see anything amiss with MISO's generator outage length and notice requirements, either. It agreed with FERC that MISO's 31-day limit "would give generators enough time to perform maintenance, while also ensuring that generators would be online for the majority of each season." It disagreed with Entergy that the threshold would hinder necessary, extended outages.

MISO requires capacity resource owners either must acquire replacement capacity or pay penalties if they are offline for more than 31 days in a season and that they must notify it 120 days in advance of planned outages to be exempt from accreditation reductions.

"FERC reasonably explained that owners of such resources have four options: shortening maintenance; acquiring replacement capacity; opting out of the capacity market for a season while maintenance is undertaken; and scheduling maintenance so that it straddles two seasons, enabling planned outages of up to 62 days in length," the court said. "As FERC explained, it is unfair for resources to go offline for more than 31 days in a season when distributors have paid for the resource's commitment to supply electricity during that season."

The court further said it made sense for MISO to require notification of outages before the start of a season so it can anticipate capacity supply.

MISO began using the seasonal, availability-based capacity accreditation in the 2023/24 planning year. FERC last year rejected Entergy's attempts to secure waivers for two of its plants, so it wasn't affected by MISO's accreditation rule, which assigns thermal units a zero-capacity credit when they take longer than 24 hours to start up. (See *FERC Rejects MISO South Waiver Requests from MISO Accreditation Standard*.)

Despite MISO's relatively recent move to its current accreditation method, it isn't here to stay for long. MISO again plans to modify its accreditation style so nearly all resources are valued based on a combination of probabilistic and historical availability. (See *MISO: New Capacity Accreditation Filing Imminent*.) ■

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FERC Accepts NYISO Capacity Accreditation Changes, with 1-Year Delay

By Vincent Gabrielle

FERC on July 23 approved NYISO's proposed tariff revisions to more accurately accredit natural gas resources' capacity, but the commission delayed their implementation until 2026 (*ER24-2096*).

NYISO pitched the changes as a way to help improve winter reliability by accounting for gas supply constraints and correlated derates in its capacity accreditation framework, which measures resources' marginal contribution to resource adequacy.

Among the changes is a requirement that generators tell it by Aug. 1 prior to each capability year how much of their capacity was covered by firm fuel supply.

NYISO had proposed implementing this provision beginning with the next capability year, which begins May 1, 2025. That would mean generators would have just a week after the revisions went into effect to make their determinations. But the ISO also said it and the New York State Reliability Council had not finalized the modeling changes needed to differentiate firm versus non-firm fuel in its resource adequacy models, nor were they likely to be finished by Aug. 1.

Though they supported the new rules, the Independent Power Producers of New York and the Ravenswood Generating Station asked FERC to delay implementation until next year. NYISO did not oppose the request.

"The problem was that without firm or non-firm definitions on Aug. 1, our capacity suppliers would have to elect" as firm resources, said Richard Bratton, director of market policy and regulatory affairs for IPPNY. "We should be in a good place by next spring in terms of what firm and non-firm mean, so that our generators can understand whether it's economical for them to elect firm or non-firm for the following capability year."

Other changes include accounting for a generator's ability to store on-site fuel and for the temperature of generators' cooling water. The revisions also eliminate the category of " capacity-limited resource," defined as a generator that is able to take extraordinary measures to increase its output above its normal upper operating limit. NYISO deemed this no longer necessary based on the other provisions in the proposal.

FERC agreed that the revisions would help NYISO more accurately align resources' stated capacity with their actual output capability and therefore better reflect their ability to meet the ISO's capacity requirements. The commission directed NYISO to submit a compliance filing within 30 days reflecting the delayed implementation date of the fuel supply rule. Commissioners Lindsay See and Judy Chang did not participate.

NYISO anticipates its system will flip to winter peaking in the 2030s. Some zones are already winter peaking, according to its 2024 *Gold Book*. ■

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Prelim NYISO Analysis: 1-GW Shortfall by 2034

By Vincent Gabrielle

New York will be short 1 GW of resources by 2034, driven by increased demand, large load growth and lack of natural gas, according to the *preliminary results* of NYISO's biennial Reliability Needs Assessment.

"Preliminary results show criteria violations that will result in reliability needs," Ross Altman, senior manager of reliability planning for NYISO, told the Electric System Planning Working Group and Transmission Planning Advisory Subcommittee on July 25. "However, we are not defining those needs today. These are still preliminary results."

New York City will experience a security margin baseline deficiency beginning as early as 2031, driven by the retirement of the New York Power Authority's small gas plants. Altman said this could be expected to grow to 275 MW by 2034 because of demand growth.

"This is driven both by New York City load growth and also the assumption of the retirement of several small gas plants that NYPA is required by law to retire or replace," Altman said.

Altman said that the final results of the RNA, to be presented in August, would identify some needs but that there would be more detail in the solicitations for next year.

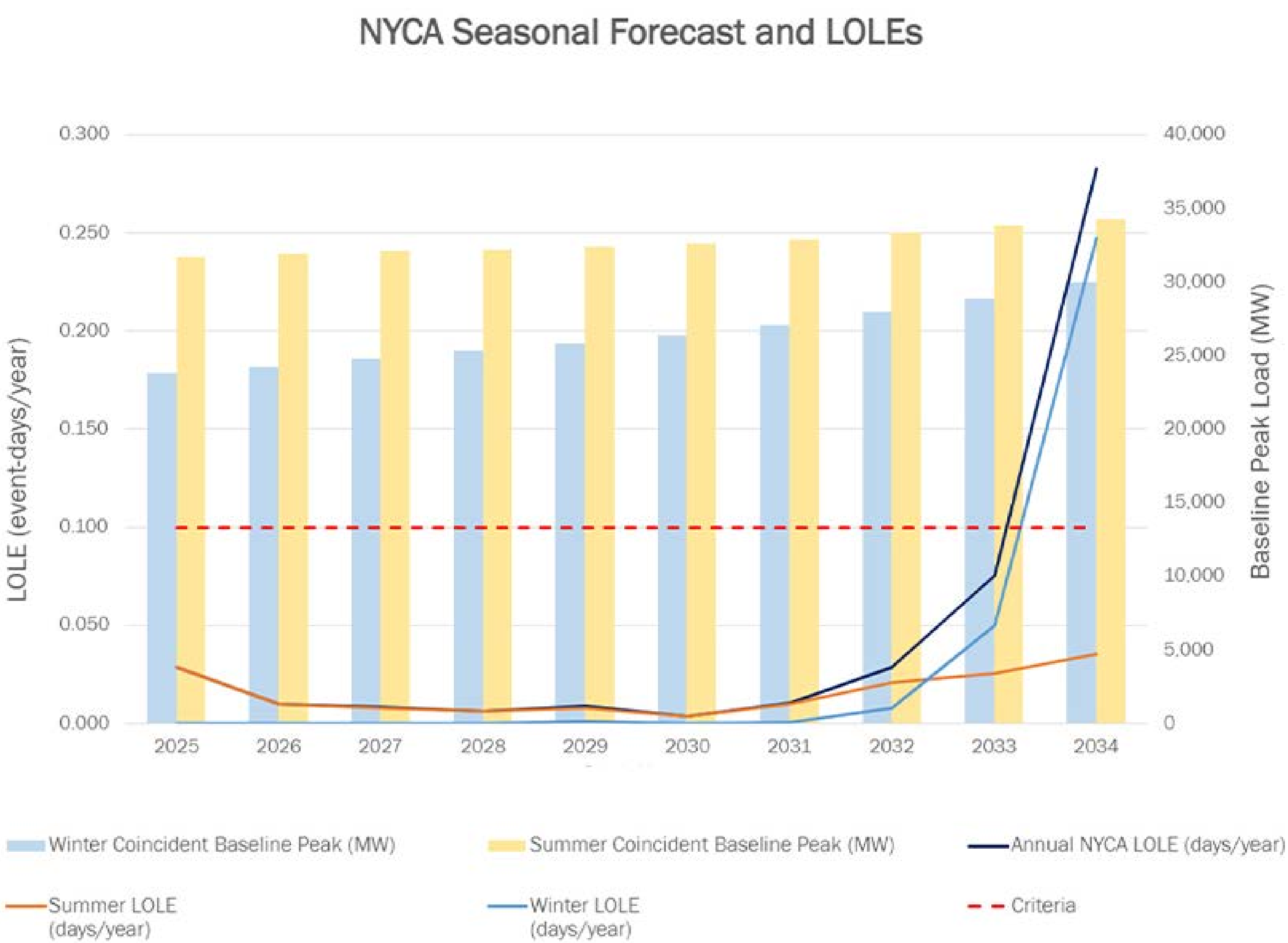
Assumptions

The preliminary RNA assumes that many large generation projects will be online and contributing to the grid, including both the Empire Wind 1 and Sunrise Wind 2 offshore wind projects.

"This is a fairly small list, but we are tracking a much wider pool of projects," Altman said. "This is a fairly conservative assumption. These are only the projects that we have high confidence on because they've met their milestones."

Approximately 6,400 MW of generation fueled by non-firm gas was modeled as unavailable. Altman said this modeling change was consistent with recently adopted changes to New York State Reliability Council rules. Dual-fuel sources with non-firm gas were modeled running on their alternate fuels.

"We wanted to highlight dual-fuel units that have non-firm gas contracts; we do not assume



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those out," Altman said. "We just model what their capability is when they're operating on their alternate fuel source."

Additionally, roughly 2,100 MW of additional large loads were added to the system. Electrical imports from Chateauguay, Quebec, were set to 0 MW during winter months.

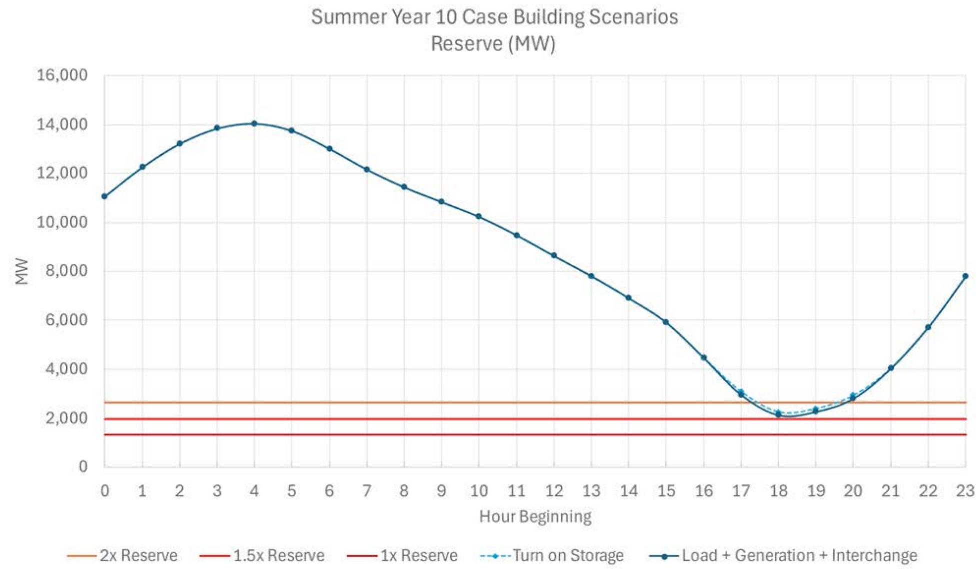
"We are setting those imports to zero in winter peak months consistent with our coordination with Hydro-Quebec and what we're seeing in operations," Altman said.

Preliminary Results

Ten years from now, NYISO estimates a loss-of-load expectation as high as 0.283.

"We need resources at that point to bring the LOLE to 0.1," said Laura Popa, a manager of resource planning for NYISO.

Popa walked stakeholders through alternate 2034 scenarios in which additional risk factors and potential solutions were modeled, including the inclusion of 9,000 MW of offshore wind, construction delays on the Champlain Hudson Power Express transmission project and the removal of certain large loads. Delaying the CHPE project would significantly impact the LOLE, bumping it up to 0.327 by 2034. Adding extra wind power or removing 1,900 MW of large load would bring the state below the 0.1 LOLE threshold.



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Most questions from stakeholders centered on the math and assumptions of the model. Some wondered whether gas was being appropriately modeled as unavailable. Altman pointed out that New England was particularly dependent on natural gas and that it would continue to be used for heat, even if new construction was electrified.

"I don't think anyone should take these results as 'the sky is falling,'" Altman said. NYISO would prefer market-based solutions to the problem and believes it could identify an appropriate solution if it went through a solicitation process, he said. ■

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NYISO Stakeholders Continue Debate over Battery as Proxy Unit

By Vincent Gabrielle

NYISO analysts continue to recommend a two-hour battery electric storage system (BESS) resource as the proxy unit for the ISO's capacity market demand curve.

"Based upon our review of the comments and the results developed to date, we continue to recommend the two-hour battery storage system as the peaking plant technology," Paul Hibbard, vice president of Analysis Group, told the Installed Capacity Working Group on July 23.

This was the second-to-last working group meeting focused on its quadrennial demand curve reset for 2025-2029, and the first since stakeholders submitted comments on the recommendation earlier this month. (See *Stakeholders Battle over Battery as Proxy in NYISO Demand Curve Reset*.)

"There are no established minimum thresholds regarding the quantity or duration of energy a peaking plant must be capable of producing during peak periods to be considered a viable technology option for the purposes of the demand curve reset," said Hibbard, responding directly to comments in opposition to the recommendation.

When asked if Analysis Group had done any reliability analysis to determine whether a two-hour duration was sufficient for maintaining reliability, Hibbard said that his group did not do reliability modeling.

"We're not trying to model a system that's operating entirely on two-hour batteries; the two-hour batteries are the peaking technology for the purpose of setting the demand curve," Hibbard said.

"Another risk of the two-hour BESS is that it is very heavily reliant on reserve revenues, and it's a reserve provider for 95% of the intervals," said Mark Younger, of Hudson Energy Economics. "Did you at all consider if there is a risk, say, if the reserve price dropped in half, or if the reserve price dropped by three-quarters?"

"We haven't tried to forecast reserve prices," answered Todd Schatzki, principal of Analysis Group. "Ultimately that gets reflected in the net EAS [energy and ancillary services offset] calculation over time."

One stakeholder noted that commenters had expressed concern with a battery's capacity accreditation factors (CAFS) diminishing very rapidly.

"We don't really feel we have a sufficient quantitative basis to assume the CAFs will decline over time," Schatzki said. "We recognize that a lot of commenters believe that is going to be the case."

Schatzki said that there were a lot of uncertainties with respect to calculating future CAFs for any technology and that final financial parameters had not yet been set.

1898 and Co., a consulting and analysis firm brought in by Analysis Group, presented some modifications to their calculations for capital and equipment costs for two-hour batteries. Based on feedback from stakeholders, real estate and land-lease costs in New York City were adjusted upward.

Discussion of how 1898 had calculated the costs of battery construction dominated the second presentation.

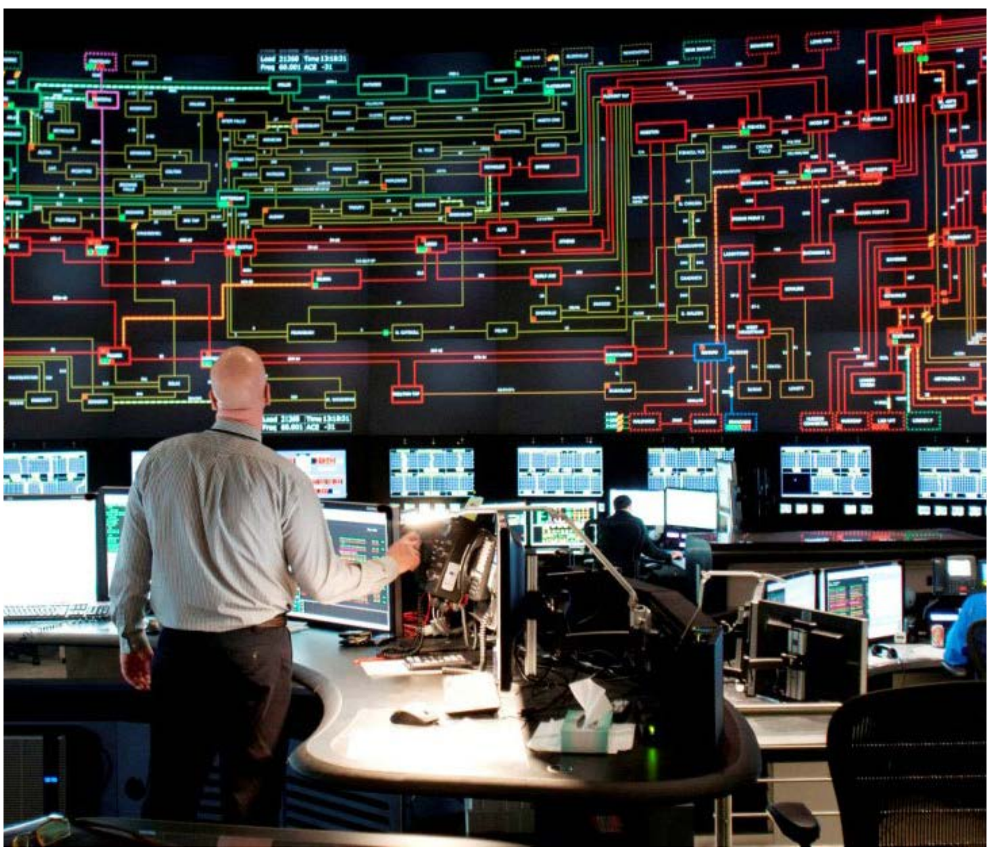
"Essentially it's the supply and demand of electric vehicles that drives what happens in the lithium carbonate market," said Kieran McInerney, a consultant with 1898. "If you look at the numbers for stationary storage verses EV demand for the raw material, it's like 95% to 5%."

McInerney said that currently, the lithium carbonate market is relatively stable and that the numbers had returned to pre-COVID pandemic prices.

"I do not intend to predict the future; anything could change at any time," he said. "But we do think that the costs that we are going to include in the final report are indicative of where the market is right now. … There's a decent amount of stability in the raw material price."

There was some discussion of how to properly account for inflation, which one stakeholder said is "crushing everything." McInerney said that he wanted the inflation indices to reliably track costs.

"We believe it's settling. It's been a crazy last nine months, [or] year, with the reductions," he said. "There's cost increases and reductions that are due to materials; there's technology changing. I can't sit here today and tell you anything. Four years ago, we all thought the price was going to be lower today." ■



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

PJM News

PJM MRC Briefs

Stakeholders Endorse Reserve Rework, Reject Procurement Flexibility

VALLEY FORGE, Pa. — PJM's Markets and Reliability Committee endorsed one of two *proposals* to revise how PJM uses reserve resources, approving a deployment scheme where instructions are sent by basepoints, while rejecting a parallel proposal to grant operators the ability to dynamically increase market procurements. (See "First Read on 2 PJM Proposals to Revise Reserve Markets," *PJM MRC/MC Briefs: June 27, 2024*.)

PJM's Emily Barrett said updating basepoints with reserve instructions provides more clarity around how resources are expected to respond and allows for units to be dispatched for less than their full reserve assignment. Resources being asked to respond at less than their assignment will be committed at the greater of their economic minimum parameter or the pro rata instruction.

Stakeholders rejected a second proposal to determine the amount of 30-minute reserves PJM commits using a formula rather than the static 3,000-MW figure. The equation would select the greater of the load forecast error and forced outage rate together multiplied by the forecast peak load, the primary reserve requirement or the largest active gas contingency.

The package would also have allowed operators to increase one of the three reserve categories without having to increase all three. Under the status quo language, any out-of-market increase in the 30-minute, primary or synchronized reserve requirement must be mirrored across all three. Barrett said the language tying the three reserve products together is viewed by staff as an oversight.

Prior to the vote, PJM's Executive Director of System Operations Dave Souder said the static reserve threshold is not sufficient and does not account for risks identified by dispatchers. The proposal would revert to the reserve procurement formula in place before the reserve price formation redesign.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said outages experienced in Alberta, Canada, in April demonstrated the importance of having dispatchers able to match reserves with expected risk.

"The Alberta outage a few months ago shows why this is needed, the renewable forecast was inaccurate, energy commitments were too low and firm load had to be shed. That provides a cautionary tale that lends support for the ability to commit more reserves available," Sotkiewicz said.

Adam Keech, PJM | *© RTO Insider LLC*

According to the PJM summarized voting *report*, the reserve procurement package had little support among electric distribution companies, which were 93.1% opposed, and end-use consumers, which voted 82.4% against. The Other Suppliers sector was split at 57.1% support, while generation and transmission owners were united in support.

Responding to a stakeholder question about whether PJM would consider moving forward with the proposed tariff changes without stakeholder endorsement, PJM Vice President of Market Design and Economics Adam Keech said staff had not envisioned the vote failing and will have to consider next steps.

Schedule Selection Formula Endorsed

Stakeholders endorsed a *proposal* to use a formula to sift through market sellers' energy offers into the real-time market and select one schedule for each resource to be modeled in the market clearing engine (MCE). (See "Stakeholders Discuss Path Forward on Multi-Schedule Modeling," *PJM MIC Briefs: June 5, 2024*.)

PJM brought the issue before stakeholders as part of its effort to implement multi-schedule modeling in the real-time market, which staff have said would result in a significant increase in computation times, in part due to the number of configurations combined cycle units can operate under. The introduction of multi-schedule modeling is one part of a larger overhaul of the engine under PJM's Next Generation Markets (nGEM) initiative.

An earlier schedule selection proposal was endorsed by stakeholders but rejected by FERC in March. The commission cited a "crossing-offer-curves" scenario the Independent Market Monitor raised, under which PJM's proposed formula would select market-based offers based on its dispatch cost at EcoMin even if it would be notably more expensive than a cost-based offer at higher outputs.

The proposal endorsed July 24 is built around the same formula but aims to address the crossing curves issue by selecting price-based offers only when a resource passes the three pivotal suppliers (TPS) test and mitigating resources to their cost-based offers should they fail the TPS test. The tariff and operating agreement (OA) revisions are set to go before the Members Committee on Aug. 21 for an endorsement vote.

The proposal was sponsored by PJM and the GT Power Group at the Market Implementation Committee and received the second-highest amount of support at the MRC in December. (See "Stakeholders Endorse Multi-schedule Modeling Solution," *PJM MRC/MC Briefs: Dec. 20, 2023*.)

Monitor Joe Bowring said the joint proposal would not resolve an issue with how dual-fuel units are committed. Since only one schedule is considered, the Monitor has argued that dual fuel units may be selected to run on a schedule using a fuel that is not economical for a portion of the day.

Stakeholders had discussed waiving truncated voting rules and widening the vote to include a joint proposal from the Monitor and GT Power, which would allow generators to determine which of their offers would result in the lowest production cost and should be modeled in the MCE.

Vote on Enhanced Know Your Customer Deferred

The committee delayed voting on a *proposal* to tighten PJM's "know your customer" (KYC) requirements to require more due diligence checks on principals and key decision makers among member entities. (See "First Read on Expanded 'Know Your Customer' Rules," *PJM MRC/MC Briefs: June 27, 2024*.)

The proposal would require PJM background checks on beneficial owners, board of director members and principals of non-publicly traded members. Those entities would be responsible for providing a list of names for each of those categories and government-issued identifications, though the latter does not apply to boards unless requested by PJM. The proposal is specifically aimed at collecting more information on non-public members not required to report ownership information to the Securities and Exchange Commission.

The beneficial owner definition is applicable to those who own, control or hold 10% or more voting power of an entity, either directly or with family. Since the June 27 first read, Assistant General Counsel Eric Scherling said the definition of family members was clarified to state that ownership split across spouses, domestic partners, parents, children or siblings counts toward triggering the requirement.

The proposed definition of "principals" was also revised to add the phrase "corporate-level strategy" regarding the control individuals have over the member entity's operations. Scherling said the change is meant to address feedback that the definition could be too broad and capture staff with day-to-day operational control over assets.

Several stakeholders said they would need more time to review the changes and expressed continued concerns about the scope of the requested information.

Sotkiewicz said the principal definition remains nebulous when considering parent corporations and subsidiaries with split ownership. He motioned to defer voting until the Aug. 21 MRC meeting to provide more time to review the revised language.

"This is an arduous process for people [who] happen to be partners but don't necessarily have full decision-making authority. ... This could turn into a paperwork nightmare and for what reason we're not entirely sure" when the parent company is publicly traded and the ownership is clear, he said.

John Horstmann, senior director of RTO affairs for Dayton Light and Power, said some members have widespread operations that go far beyond PJM markets and that principals managing activities unrelated to PJM could be captured in the KYC requirements. He gave the example of an international corporation that does business in the U.S. and overseas, questioning whether information about corporate staff overseeing activities in Bulgaria or Vietnam would be requested by PJM.

Scherling said PJM's focus is on its markets and that it intends to take a closer look at individuals who are high enough in the corporate structure that they would have a hand in all operations, including PJM.

PJM Chief Risk Officer Carl Coscia said the KYC structure is about following where PJM revenues are going, what they're being used for and where investments are coming from, so it does need to go to the highest corporate-level strategy.

"We want to make sure these markets are being used for good. That's the good we're talking about, not having money that shouldn't be here," he said.

Scope for Deactivation Task Force Widened

Stakeholders endorsed a wider *scope* for the Deactivation Enhancement Senior Task Force (DESTF) to include proposals to establish cost-effective alternatives to reliability-must-run (RMR) agreements and technologies that could expedite resolution of transmission violations prompted by resource deactivations. The proposal passed with 89% support. (See "Consumer Advocates Seek Wider Scope for Deactivation Task Force," *PJM MRC/MC Briefs: June 27, 2024*.)

The revisions to the issue charge also include education on the alternatives to RMR contacts that other RTOs have developed to keep generators operating past their desired deactivation date and a follow-up to ongoing discussion on proposals to allow capacity interconnection rights (CIRs) to be transferred from deactivating generators to planned resources. The proposal is jointly sponsored by the Illinois Citizens Utility Board (CUB) and Maryland Office of People's Counsel (OPC).

The issue charge language includes education around using grid-enhancing technologies (GETs) and storage as a transmission asset (SATA) to expedite transmission upgrades necessary to allow a generator to retire.

Souder said PJM is neutral toward the technology that resolves an identified violation and it's up to project proposers to submit solutions, including GETs.

Clara Summers, of CUB, said the proposed language was revised from the draft presented at the June 27 first read to allow partial solutions, with the goal of avoiding any interruption to the existing discussions on compensation and deactivation notification timelines.

Vistra's Erik Heinle said he is concerned about having too wide of a scope for the task force, stating that the wide-ranging issue charge governing the Resource Adequacy Senior Task Force (RASTF) caused the group to die under its own weight while the Reserve Certainty Senior Task Force (RCSTF) has benefited from a narrower scope.

"I want to make sure these important issues get the consideration they deserve but don't slow down the ongoing work," he said.

Bowring questioned whether the advocates believe the issue charge should be phased to focus on deactivation notification requirements and compensation first before initiating work on the newly added items.

Phil Sussler, of the Maryland OPC, responded that stakeholders may be too optimistic that the deactivation notification changes will be approved in August and said the overall work areas of the DESTF may take longer than expected to complete.

Reserve Requirement Study Updated with ELCC Accreditation Values

The committee voted by *acclamation* to endorse revised installed reserve margin (IRM) and forecast pool requirement (FPR) values for the 2023 Reserve Requirement Study (RRS) to reflect the implementation of PJM's marginal effective load carrying capability (ELCC) approach to accrediting resources. The proposal was also endorsed by the Members Committee on July 24.

The reanalysis recommended increasing the installed reserve margin (IRM), which sets the targeted capacity level above expected loads, to 18.6%, up from the 17.6% stakeholders endorsed last year for the 2023 RRS. The forecast pool requirement (FPR), which accounts for generator accreditation, would decrease from 11.65% to 9.37.

The shift to marginal ELCC accreditation was part of a package of capacity market redesigns approved by FERC in January (*ER24-99*). The RRS figures are used to set the supply curve for the 2026/27 delivery year. (See *PJM Presents Revised Reserve Requirement Study Values.*)

In addition to the ELCC accreditation values, the reanalysis updated the expected resource mix to include planned resources that submitted a notice of intent to offer into the 2026/27 Base Residual Auction. Gas generators that submitted dual fuel attestations were sorted into the corresponding ELCC classes, and resources that are scheduled to deactivate prior to the start of the delivery year were removed from the analysis. Generators expected to operate on reliability-must-run (RMR) contracts through the delivery year were included in the resource mix.

Greg Carmean, executive director of the Organization of PJM States Inc. (OPSI), questioned how PJM would incorporate nuclear capacity

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being removed from the market to serve data center load, referring to a FERC filing from Talen Energy to reduce the amount of energy the Susquehanna nuclear plant sells into PJM. (See *Talen Energy Deal with Data Center Leads to Cost Shifting Debate at FERC.*)

PJM's Andrew Gledhill said the megawatt value of that unit would be effectively derated to the new CIR amount.

Bowring asked how PJM considers the reliability impact of amending interconnection service agreements (ISAs) with generators to reduce their maximum output and whether it considers not approving revisions if there are reliability impacts identified.

PJM's Pat Bruno said reliability analysis is conducted like generation deactivation studies.

PJM Proposes Increased CONE Parameters

PJM's Skyler Marzewski *presented* a first read on a proposal to revise two financial parameters used to calculate the cost of new entry (CONE) input to the 2027/28 Base Residual Auction (BRA). (See *PJM MIC Briefs: July 10, 2024*.)

After consulting with The Brattle Group, PJM recommended increasing the after-tax weighted average cost of capital (ATWACC) from 8.85 to 10% and using a 0% bonus depreciation rate for the 2027/28 delivery year and beyond. The original quadrennial review included a 20% bonus depreciation value for the 2026/27 year. The proposed changes to the quadrennial review would also update the Bureau of Labor and Statistics (BLS) indices used in capital cost escalation rates.

The *changes* increase values for all five CONE areas by an average of $79/MW-day, with CONE Area 5 seeing the largest increase at $90/MW-day and Area 4 increasing by $65/MW-day.

The review was triggered by market participants reaching out to PJM regarding the impact of high interest rates since the quadrennial review was approved last year. (See *FERC Approves PJM Quadrennial Review.*)

Greg Poulos, executive director of the Consumer Advocates of PJM States (CAPS), said some advocates are frustrated that components of the review are being cherry-picked in a manner that increases consumer costs, both in terms of the financial parameters and the creation of an additional CONE area for Illinois. (See *PJM Stakeholders Approve New CONE Area for ComEd over Consumer Opposition.*)

Summers questioned how PJM determines when it is appropriate to make changes to CONE outside of the quadrennial review.

Marzewski said PJM and Brattle opted to not include automatic adjustments to the quadrennial review financial parameters to account for changing market conditions, instead leaving that discussion for the next quadrennial review.

Sotkiewicz said the adjusted figures would be a short-term fix, but major issues remain with the CONE inputs, namely the use of a combined cycle generator as the reference resource at a time when few such units are under construction within PJM and none have been financed in recent years.

New Economic DR Parameters Discussed

PJM presented a *proposal* to add two new parameters for demand response resources offering into the energy market, allowing providers to set a maximum dispatch period and a minimum interval before they can be committed again after being released from a previous dispatch. The Market Implementation Committee endorsed the proposal last month. (See "Additional Parameters for Demand Response Endorsed," *PJM MIC Briefs: June 5, 2024*.)

PJM's Pete Langbein said the proposal would allow DR providers to enroll consumers that are only economic for set periods of time and need a recharge before being committed again. While some of that capability exists under the existing market structure using hourly updates, it is administratively difficult.

Bowring questioned whether a DR resource could submit an offer into the capacity market even if it can only operate according to the proposed parameters. Langbein said such a resource would be subject to capacity performance (CP) penalties if it did not deliver during a performance assessment interval (PAI). ■

— Devin Leith-Yessian

FERC Accepts SPP Congestion Hedging Changes

By Tom Kleckner

FERC filed a letter order July 25 accepting SPP's proposed tariff revisions to implement congestion hedging improvements, ending a journey through the stakeholder process that began six years ago (*ER24-1775*).

The commission found SPP's proposal will "improve market participants' ability to hedge congestion costs by allowing SPP's models to reflect congestion more accurately; allocating [long-term congestion rights], [incremental LTCRs] and [auction revenue rights] more broadly and equitably among eligible entities; and distributing surplus auction revenues more equitably."

SPP's change request is a result of the stakeholder-driven Holistic Integrated Tariff Team's work in 2018/19. The team's charges included developing a high-level policy recommendation that aligns the grid operator's transmission planning processes and resource adequacy needs with its markets and tariff requirements.

Staff and stakeholders developed a package of eight congestion-hedging policies that were approved by the board and state regulators in February. (See "Congestion-hedging Policies' Implementation," *SPP Board of Directors/Members Committee Briefs: Feb. 5-6, 2024*.)

SPP said the changes better align the network models it uses in the simultaneous feasibility test with the studies it uses to grant transmission service. That will prevent some transmission paths from not capturing all congestion and other paths that look feasible but do not offset the congestion experienced by load.

The RTO is changing the process for awarding LTCRs and ILTCRs and the annual ARR allocation of ARRs by using a two-step, single round process in the second round of the LTCR allocation, knocking off two rounds. Eligible entities will be allowed to nominate 50% of their ARR nomination cap, reduced by the LTCRs awarded. Entities that receive a higher number of LTCR awards will nominate fewer ARRs in the first round of the ARR allocation.

Also, SPP will break the simultaneous feasibility test performed during the second round of the LTCR/ILTCR allocation and the first round of the annual ARR allocation into five equal subrounds. Because breaking the simultaneous feasibility test into smaller increments makes it less likely that large portions of awards will go to a single entity, LTCR/ILTCR and annual ARR awards will be allocated more broadly and equitably.

The grid operator is changing the distribution of surplus auction revenues by awarding them in greater proportions to eligible entities that received a lower proportion of LTCRs and ARRs tied to firm transmission service. The new approach will be phased in halfway into the first year (2025/26) to reduce the effect of revenue shifts.

The revisions exclude transmission service reservations that do not source at a resource or a resource hub in the commercial model from being verified and used for LTCR and ARR nominations. SPP will apply the same exclusion when assessing grandfathered agreement transmission rights, and transmission service reservation holders will be allowed to update existing services' sources to specific resources or resource hubs in the commercial model without triggering an aggregate transmission service study process.

SPP's Market Monitoring Unit said the grid operator's proposal will create more equity in allocating ARRs, LTCRs and ILTCRs and a more equitable distribution of surplus auction revenue among market participants owning firm transmission rights. It supported the revised method of distributing surplus auction revenues.

Intervening in the docket were American Electric Power Service Corp., on behalf of its affiliates Public Service Company of Oklahoma, Southwestern Electric Power Co., AEP Oklahoma Transmission Co. and AEP Southwestern Transmission Co.; Evergy Kansas Central, Evergy Metro and Evergy Missouri West; Kansas Electric Power Cooperative; Lincoln Electric System; Midwest Energy; Missouri River Energy Services; Omaha Public Power District; Public Citizen; Western Farmers Electric Cooperative; and Xcel Energy Services, on behalf of affiliate Southwestern Public Service Co. ■

FERC has approved changes to SPP's congestion hedging practices. | *GridLiance*

Company News

NextEra Reports Continued Growth in Renewables

Data Center Agreements Boost Backlog Above 22 GW

By John Cropley

NextEra Energy *reported solid quarterly earnings* July 24, and its renewables business turned in its second-best quarter ever, signing agreements for more than 3 GW of new renewables and storage.

Data center agreements with Google totaling 860 MW and other additions brought the NextEra Energy Resources backlog to 22.6 GW, even as it placed more than 1.6 GW into service in the second quarter.

During a conference call July 24, CEO John Ketchum updated financial analysts on other aspects of the company's business landscape, including the figurative elephant in the room: The political party that has embraced the pachyderm as its symbol.

A week after the Republican Party formally designated a truculent renewable energy skeptic as its standard bearer, one of the world's largest operators of wind, solar and storage might be concerned about the shape of things to come.

But Ketchum reeled off a list of reasons why he is not alarmed by the prospect of a second Trump presidency:

- Money from Democrat-backed clean energy programs is going disproportionately to Republican-leaning states.
- Republican lawmakers increasingly are embracing IRA tax credits when they see the impact in their districts.
- Tax laws are difficult to change.
- Party majorities are likely to remain narrow in the House and Senate.
- Renewables create jobs, they sidestep fuel price volatility, they bring down constituents' power bills and they help meet the growing demand for electricity.

"We've always been able to work with both sides of the aisle in the 22 years that I've been at NextEra, and I don't think this time around is any different," Ketchum said.

The company expects 6 to 8% annual growth in earnings per share through 2027.

NextEra Energy Resources benefits from multiple growth paths, Ketchum said:

There is the replacement cycle, by which higher-cost, lower-efficiency generation is replaced by renewables and energy storage. The company says with its affiliates, it is the world's leading generator of electricity from wind and sunlight and one of the leading storage operators.

FPL's Manatee Energy Storage Center is shown in Parrish, Fla. | *NextEra Energy*

There also is rising demand.

Most markets have seen stagnant demand for decades, Ketchum said, with one of the exceptions being Florida, where NextEra's FPL operates as the nation's largest electric utility.

But now, growth is coming across multiple sectors in multiple markets.

"We expect the demand for new renewables to triple over the next seven years vs. the prior seven to help meet this increased power demand," Ketchum said.

NextEra is ready to help meet the rising demand for clean energy, but it is not ready to turn off its fossil generation — an all-of-the-above solution is needed, he said.

"As the owner and operator of a large natural gas-fired fleet in Florida, we are also conscious of the importance of natural gas-fired generation as a bridge fuel," Ketchum said.

That said, building new gas-fired generation has become challenging, he added — more expensive and time-consuming in many states.

An analyst asked about the other emissions-free part of NextEra's portfolio: nuclear. Has there been any thought to restarting the Duane Arnold Energy Center in Iowa?

Its license had been extended to 2034, but it shut down in 2020 after sustaining wind damage.

Yes, Ketchum said — but only thought.

"Sure, we're looking at it, but we would only do it if we could do it in a way that is essentially risk-free with plenty of mitigants around the approach, and there are a few things that we would have to work through," he said.

NextEra Energy reported second-quarter 2024 net income of $1.62 billion, or $0.79 per share, on $6.07 billion in revenue.

This compares with net income of $2.8 billion, or $1.38 per share, on revenue of $7.35 billion in the second quarter of 2023.

NextEra Energy stock closed 4.6% higher in trading July 24. It is part of the S&P 500, which was down 2.3% for the day. ■

Company Briefs

EQT, Equitrans Merge in $5.45B Deal

EQT Corp. last week agreed to a deal with former subsidiary Equitrans Midstream Corp., closing on a $5.45 billion acquisition.

EQT, the nation's largest natural gas producer, announced its intention to reunite with Equitrans in March. The two were part of the same company until Equitrans spun out in 2018 as a pipeline and compression provider.

More: *Pittsburgh Post-Gazette*

Tesla's Net Income Falls 45% in Q2

Tesla last week reported a second-quarter net income of nearly $1.5 billion, a 45% decline from the $2.7 billion a year earlier, as sales of its core cars dipped 5%.

Total revenue was $25.5 billion in the quarter ended, a record, up 2% from $24.9 billion a year earlier.

More: *Houston Chronicle*

Nexamp, Starbucks Partner on Community Solar Projects

Nexamp and Starbucks last week announced a partnership to deploy 40 MW across six Illinois community solar farms.

Starbucks will receive a portion of the project's RECs for its support of Nexamp's Illinois operations.

Construction has begun on the solar projects, which are expected to come online next year.

More: *Solar Industry Magazine*

Federal Briefs

Campaign Official: Harris Does not Support Fracking Ban

Vice President **Kamala Harris** will not seek to ban fracking if she's elected president, an official with her campaign said last week.

While she was one of several Democrats vying for the 2020 nomination, Harris said, "There's no question I'm in favor of banning fracking." However, since that time, she joined the Biden campaign and administration, neither of which supports a ban on fracking.

More: *The Hill*

Republicans Ask Supreme Court to Pause New EPA Rules on Emissions

More than 20 Republican state attorneys general last week asked the Supreme Court to temporarily block the EPA from enforcing new rules that aim to curb carbon emissions from power plants.

The filing came days after a federal appeals court turned down a similar emergency request from the officials and industry groups. They want the new rules shelved while their legal challenge plays out.

The EPA's new rules will compel existing coal and new natural gas power plants to either cut or capture 90% of their emissions by 2032. The rules are expected to reduce carbon dioxide emissions from the sector by 75% compared to a peak in 2005. The challengers say the rules would be too costly for power plants and could force them to close.

More: *CNN*

DOI Advances Clean Energy Projects on Western Public Lands

The Department of the Interior last week announced that the Bureau of Land Management will advance nine solar projects on public lands.

The actions follow the department's April announcement that the BLM has permitted more than 25 GW of clean energy projects – surpassing a major milestone ahead of 2025.

More: *Department of Interior*

State Briefs

FLORIDA

Duke Energy Cuts Rate Hike Request, Won't Shut off Power at 95 Degrees

Duke Energy last week agreed to a settlement with the Public Service Commission to drastically decrease its rate increase request.

Originally, Duke asked for an increase of about $820 million over the next three years. Now, the company is requesting an increase of $262 million, plus charges for solar plants that will only be added once the projects are completed. The costs of those projects would total $141 million if all are finished on schedule, the company said.

Duke also agreed to add language to its policy so that no customers will have their power disconnected if temperatures reach at least 95 degrees. Previously, it stopped shutoffs when the heat index was 105 degrees.

More: *Tampa Bay Times*

MICHIGAN

Ann Arbor Ballot Proposal Promises Affordable Access to Renewables

Ann Arbor residents will vote this November on establishing an optional public utility that would use renewable energy exclusively. The project is part of the city's A2Zero program, which aims for carbon neutrality by 2030.

A report calculated cost savings based on how much money it will cost the city to set up the utility and how many customers participate. The report said residents could save on their electricity bills by opting in to the utility.

Unlike a full-scale public utility, the sustainable utility would be supplemental, as residents and businesses would need to opt in to use it.

More: *Michigan Public Radio*

MINNESOTA

PUC Approves CenterPoint's Clean Energy Plan

The Public Utilities Commission last week approved CenterPoint Energy's $106 million clean energy plan.

CenterPoint said the five-year program will cost its average residential customer about $1.50 a month. The plan will include clean energy pilot projects such as renewable natural gas and geothermal heating.

The largest of CenterPoint's 17 pilot projects calls for $40 million in purchases of renewable natural gas. After RNG purchases, CenterPoint's next-largest proposal, costing $13.6 million, is retrofitting residences for electric heat pumps with gas backups.

More: *Star Tribune*

NEW HAMPSHIRE

Law Provides New Solar Incentives for Cities

A recently signed law has made significant changes to the state's Renewable Energy Fund, directing money to help towns and cities develop municipal solar projects.

The fund, created in 2007, is a pool of money the state uses to support renewable and thermal energy initiatives through grants and rebates. More recently, revenue has hovered around $7 million. The money is then allocated across several programs. The new legislation calls for funding to be allocated to a new municipal solar program this year, with the sum likely to be announced in late August or early September.

The bill also terminated the state's rebate program for residential solar and wind installations.

More: *Energy News Network*

NORTH CAROLINA

Police: Man Shoots Utility Tree Workers

A man shot three tree workers last week while they were clearing trees for a power company before being shot himself by police officers during his arrest, police said.

The incident began near Murphytown when 36-year-old Lucas Wilson Murphy confronted contract workers clearing the right of way for a utility, according to a statement from the Yancey County Sheriff's Office. Authorities did not release any possible motives in the case.

All three workers sustained serious injuries. Their conditions are unknown.

More: *ABC News*

TEXAS

CPS Energy Plan to Shut Braunig Units Could be Stopped by ERCOT

ERCOT will begin seeking replacement power for the gas-fired units at CPS Energy's Braunig Power Station, which the company planned to shut down by March, and failure to do so could halt the utility's plans.

The plan proposed by CPS, which is working to transition away from carbon generation, would take 859 MW off the grid. However, it is currently unclear where the replacement power could come from. To offset the Braunig loss, CPS recently bought existing gas-powered plants from Talen Energy. But because those plants were already part of ERCOT's capacity before the purchase, Braunig's closing would still result in a net loss on the grid.

ERCOT is scheduled to decide by October.

More: *Houston Chronicle*

VERMONT

CLF to Sue State over Alleged Failure to Comply with Climate Law

The Conservation Law Foundation (CLF) last week announced plans to sue the state, alleging the Agency of Natural Resources has failed to comply with a law that requires Vermont to reduce climate emissions.

In 2020, Vermont enacted the Global Warming Solutions Act, which legally requires the state to implement programs that cut greenhouse emissions in specific amounts by 2025, 2030 and 2050. The CLF is planning to use a pathway included in the law that allows organizations or individuals to sue the secretary of the Agency of Natural Resources to force compliance if evidence shows the state is not on track to meet those benchmarks. Under the law, the entity suing the state must give the agency 60 days' notice before filing a lawsuit.

The CLF alleges the agency has used faulty modeling to assert the state is on track to meet the law's first deadline on Jan. 1, 2025. The CLF conducted its own analysis and said the analysis showed the state is not likely to meet the deadline.

More: *VTDigger*

VIRGINIA

DEQ Fines Mountain Valley Pipeline for Environmental Violations

The Department of Environmental Quality last week fined Mountain Valley Pipeline $30,500 for violating environmental regulations during a three-month period before the pipeline began operating, marking the fourth consecutive fine of this type.

The DEQ levied the penalty after it found nearly two dozen violations of erosion and sediment control rules, according to a report. Nearly all problems were corrected within a day.

Before the latest penalty, the DEQ had fined Mountain Valley $68,000 over the previous three quarters since construction resumed last summer.

More: *Cardinal News*

Dominion Customers' Bills to Rise for Offshore Project Costs

The State Corporation Commission last week approved an 80% increase in the surcharge on Dominion Energy bills that finances an offshore wind project off Virginia Beach.

The increase, which goes into effect Sept. 1, will raise the average monthly bill by $3.89.

Dominion plans to erect 176 giant wind

turbines in the Atlantic and expects to have the project operational by the end of 2026.

More: *Richmond Times-Dispatch*

WASHINGTON

Initiative to Halt Phaseout of Natural Gas Makes Ballot

State election officials last week certified an initiative for the November ballot that seeks to reverse the state's attempt to phase out natural gas use in homes and other buildings.

The measure targets the state's combination of regulations and laws to move swiftly away from natural gas toward technology like electric heat pumps. It will appear first on ballots, followed by three other citizen initiatives that seek to repeal the state's cap-and-trade system and capital gains tax and make the state's new long-term care services program voluntary.

If passed, the initiative would repeal provisions of a new law meant to hasten Puget Sound Energy's transition away from natural gas. It would also bar cities and counties from prohibiting, penalizing or discouraging "the use of gas for any form of heating, or for uses related to any appliance or equipment, in any building." And it would roll back recent changes to energy requirements in building codes that are designed to get more electric heat pumps installed in newly built buildings.

More: *Washington State Standard*

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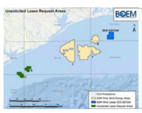
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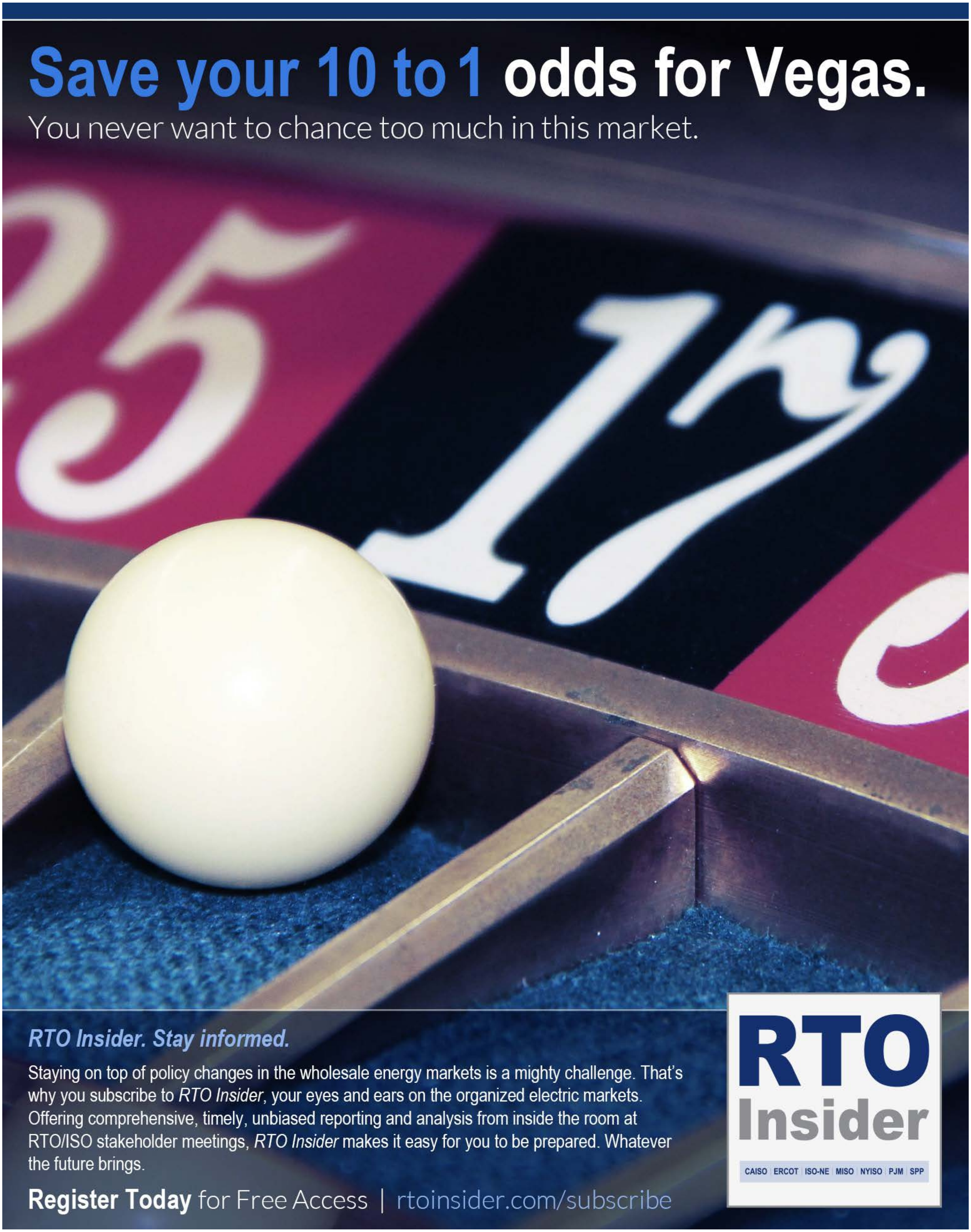
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