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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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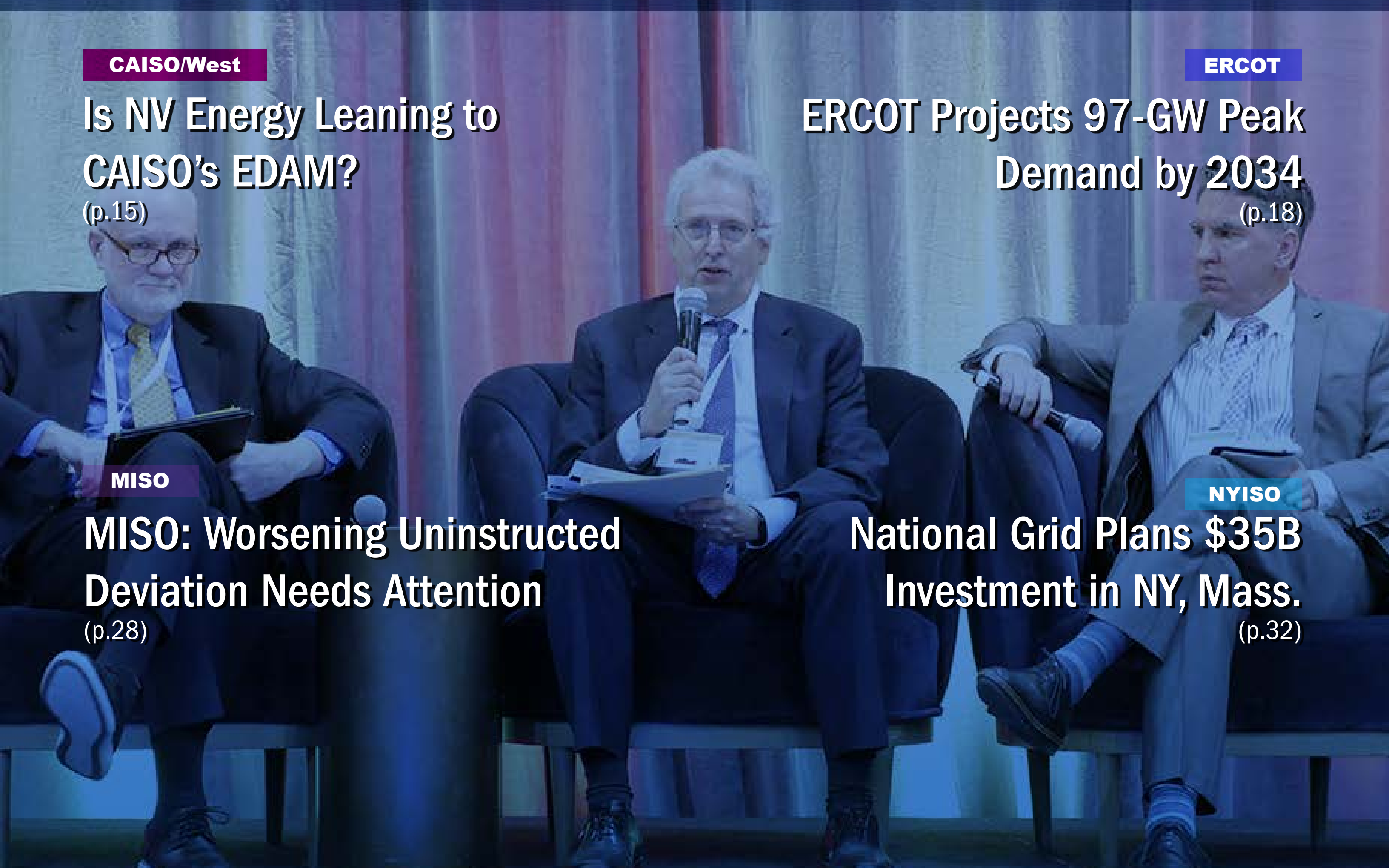

COVER: From left: FERC Commissioner Mark Christie, former FERC Chair Richard Glick and Vincent Duane, Copper Monarch *(Page 14)* |

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In this week's issue

Counterflow

By Steve Huntoon

Long-duration Energy Storage: Reality Check

By Steve Huntoon

Here's the bottom line on carbon-free electricity: The proponents envision a massive portfolio of wind and solar generation. And somehow, the intermittent nature of these renewable resources will be covered by some type of storage.

In other words, wind and solar output in excess of demand from hour to hour will charge the storage, and the storage will discharge into the grid when wind and solar output cannot meet demand.

In theory, this can work. But as it is said, "In theory, theory and practice are the same. In practice, they are not."[1]

As I've discussed before, renewable resources may collectively produce little electricity for days or weeks on end.[2] In 2018, there was a three-week period in PJM in which wind and solar resources averaged 10% of their combined nameplate capacity.[3]

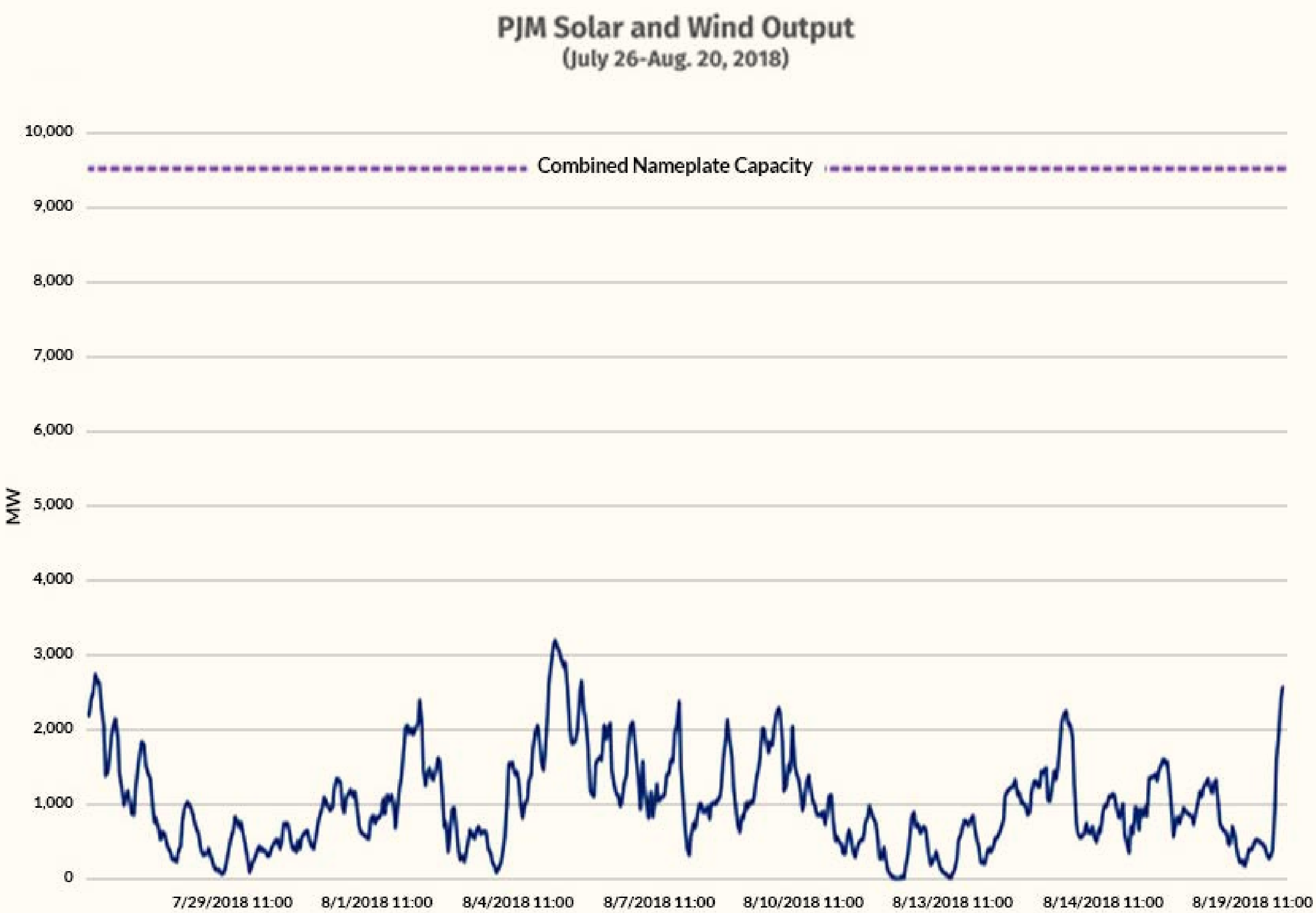
Thus, short-duration storage — one to eight-hours — is basically worthless to cover a demand/supply drought that lasts for days. Short-duration storage is discharged in Day 1; there's no net supply to recharge the storage; and that's that. Game over.

Enter Long-Duration Energy Storage

So that brings us to long-duration energy storage (LDES). This is now portrayed as the solution to extended droughts of wind and solar generation.

There are many potential types of LDES.[4] The most commonly cited type of LDES is iron-air (a.k.a. iron-rust or metal-air) battery storage, as typified by Form Energy, which has raised almost $1 billion for this technology.[5] (My take on green hydrogen for storage or anything else is here.[6])

But hard data suggest iron-air technology is not ready for prime time. Practice may trump theory again.



For more than three weeks in the summer of 2018, PJM's solar and wind generation averaged only 10% of their combined nameplate capacity of 9,694 MW. | *PJM*

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By Steve Huntoon

Poster Child: Form Energy California Project

Data points come from a California Energy Commission announcement of a $30 million grant to Form Energy for a 5-MW/500-MWh battery storage project in Mendocino County.[7] This is what's called a 100-hour storage project: 500 MWh divided by 5 MW is 100 hours. And $30 million divided by 500 MWh is $60,000/MWh.

Scoping the Challenge

As noted above, because wind/solar generation can be small for days at a time, maintaining reliability would require some way to cover net load[8] for such a period. But how many days?

A study of such renewable droughts in the U.S. came out last year.[9] The study analyzed hourly data on wind output, solar output and demand by region (balancing authority). The study is complex, but the gist is to confirm the need to somehow cover multiday renewable droughts across a given region, with California the most vulnerable, with six-day droughts to be expected. The study also found that load levels are positively correlated with droughts, so low load cannot be relied on to help cover renewable droughts.

What's It Gonna Take?

We'll assume needing battery storage to cover six days of severe renewable drought in California. With an average hourly load in California of 28.8 GWh,[10] an average 80% supply/demand deficiency[11] would be 23 GWh, which, multiplied by 24 hours and by six days, is 3,314 GWh.

What's It Gonna Cost?

Batteries to store those 3,314 GWh at a capital cost of $60,000/MWh, based on the Form Energy project, would cost $198.8 billion, which at an annual carrying charge rate of 12%[12] is $23.9 billion per year.

This is without any cost for the energy to charge the batteries, but let's optimistically assume the batteries can be charged with wind and solar otherwise curtailed so the energy cost would be negligible. Is there some substantial offsetting economic value of the batteries, such as energy arbitrage between high- and low-cost hours? Well, the round-trip efficiency is 35%,[13] which suggests limited energy arbitrage opportunity.

What is the rate impact of this? If we divide that $23.9 billion per year by California's annual electric usage of about 252,000 GWh per year,[14] the rate impact is 9.5 cents/kWh. This would about double the generation component of California's average electric rate and increase the already-high average retail rate by about 50%.[15] Yikes!

And this is just for the battery storage. The cost of the renewable generation itself is not included.

Alternatives

There are other alternatives for covering California's renewable droughts, but I'm going to focus on the existing natural gas fleet. Let's assume we can keep 23 GW around to cover the average net load of 23 GW during a renewable drought.[16] According to the California Energy Commission, the cost of retaining gas plants is between $34.26 and $43.05/kW/year.[17] I'll use the higher figure. So, the annual cost would be $990 million.

We'll need 3,314 GWh (calculated above) of generation to cover six days. We'll use the National Energy Technology Laboratory's (NETL) gas supply and other variable cost of $36.4/MWh.[18] For one six-day drought, the total fuel/variable cost is $121 million.

So, the cost to retain natural gas plants and to cover their variable costs for a six-day drought is $1.1 billion.

Comparing Battery Storage and Retained Gas Plant Costs

Comparing the annual cost of battery storage of $23.9 billion to the annual cost of retaining gas plants of $1.1 billion means it would cost 20 times as much to employ battery storage to cover renewable droughts as to retain gas plants for that purpose. Yikes!

And What About Greening Those Gas Plants?

This is where things get really interesting.

What's the additional cost to get to no (or very low) carbon using the retained natural gas plants? There are at least three options: (1) purchasing carbon offset credits for the carbon emissions from the gas plants; (2) purchasing carbon offset credits that are solely carbon capture and storage (CCS); and (3) retrofitting the gas plants with CCS facilities.

Regarding the first option, Bloomberg forecasts carbon offset credits to cost $13/ton in 2030 and $20/ton for "high-quality" offset credits under tighter rules.[19] Let's use the higher price and convert the $20/ton to $9/MWh using an Energy Information Administration conversion rate of 0.97 pounds/kWh.[20] For 3,314 GWh per year, the cost is about $30 million per year.

The second option involves carbon offset credits that are solely CCS. Bloomberg forecasts a 2030 price for such credits of $146/ton.[21] Climeworks, a developer of direct air capture plants, is forecasting a $300 to $350/ton cost in 2030 for new plants.[22] Using the highest of these costs and the preceding EIA conversion rate for 3,314 GWh per year entails a cost of about $525 million per year.

The third option is retrofitting gas plants with CCS facilities at a capital cost, according to an NETL study, of $1,212/MW,[23] which for 23 GW is $27.9 billion, which at an annual carrying cost rate of 12% is $3.3 billion per year.

The Bottom Line

Now let's compare the annual costs of long-duration battery storage with the costs of no-/low-carbon gas plant retention alternatives:

Long-duration battery storage:	$23.9 billion
Gas plants with carbon credits:	$1.1 billion
Gas plants with CCS credits:	$1.6 billion
Gas plants with CCS retrofit:	$4.4 billion

See the difference?

What About Future Cost Reductions in LDES?

This comparison of options is based on the cost of the Form Energy California project. There are claims of future large reductions in iron-air battery costs — let's assume the cost per megawatt-hour goes down by two-thirds in line with Form Energy's claimed future reduction in the kilowatt-per-year cost relative to its California project[24] and a similar two-thirds reduction hypothesized in an MIT study.[25] The economics remain dreadful relative to keeping gas plants around. And, of course, carbon offset and CCS retrofit costs may decline as well.

One More Thing

The relative cost comparisons I've offered implicitly assume the useful lives of the

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By Steve Huntoon

resources are about the same. But buried in Dominion Energy's application for battery storage projects in Virginia is a statement that the useful life of Form Energy's iron-air battery project is 10 years.[26] This is a fraction of the useful life of other battery storage technologies and of natural gas alternatives. Think of a car that will last a third as long as other cars. One more thing to think about.

Near-term Implications

"It is difficult to make predictions, especially about the future."[27] But it's this sheer uncertainty that militates for keeping natural gas plants around in some form. For example, instead of decommissioning gas plants perhaps mothball them at relatively low cost. This would preserve the option of using carbon credit offsets and/or CCS retrofit in the future.

Big Picture Implications

LDES is extremely expensive. It does not make economic sense relative to retaining natural gas plants with various carbon-abatement alternatives.

Policymakers — legislative and regulatory — should insist on apples-to-apples comparisons of alternatives for abating carbon while maintaining reliability. ■

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.

[1] https://quoteinvestigator.com/2018/04/14/theory/

[2] https://energy-counsel.com/wp-content/uploads/2022/11/More-Happy-Talk.pdf; https://www.energy-counsel.com/docs/cue-more-pixie-dust.pdf; https://www.energy-counsel.com/docs/Cue-the-Pixie-Dust.pdf; https://www.energy-counsel.com/docs/German-La-La-Land.pdf; https://www.energy-counsel.com/docs/No-Carb-California.pdf; https://energy-counsel.com/docs/Grid-Batteries-Kool-Aid-Once-More-with-Feeling-RTO-Insider-12-5-17.pdf; https://www.energy-counsel.com/docs/Battery-Storage-Drinking-the-Electric-Kool-Aid-Fortnightly-January-2016.pdf.

[3] https://www.energy-counsel.com/docs/Cue-the-Pixie-Dust.pdf

[4] https://energy.mit.edu/wp-content/uploads/2022/05/The-Future-of-Energy-Storage.pdf, pages xiii-xvii.

[5] https://www.scientificamerican.com/article/rusty-batteries-could-greatly-improve-grid-energy-storage/

[6] https://energy-counsel.com/wp-content/uploads/2023/12/Hydrogen-Reality.pdf

[7] https://www.energy.ca.gov/news/2023-12/cec-awards-30-million-100-hour-long-duration-energy-storage-project; https://www.energy.ca.gov/sites/default/files/2023-10/CEC-500-2023-055-D.pdf. The economics of this project don't reconcile with the description of a Form Energy project in New York said to be twice the size at less than half the cost, https://www.nyserda.ny.gov/About/Newsroom/2023-Announcements/2023-08-17-Governor-Hochul-Announces-Nearly-15-Million-in-Long-Duration-Energy-Storage, although one difference is that New York limits its contribution to half the project cost, https://portal.nyserda.ny.gov/servlet/servlet.FileDownload?file=00P8z000001ocKUEAY.

[8] Net load is gross load net of wind/solar generation.

[9] https://www.sciencedirect.com/science/article/pii/S0960148123014659?via%3Dihub The press release summarizing the results is here, https://www.pnnl.gov/news-media/energy-droughts-wind-and-solar-can-last-nearly-week-research-shows

[10] https://efiling.energy.ca.gov/GetDocument.aspx?tn=254463, page 13.

[11] This means that average hourly renewable generation is covering 20% of average hourly gross load. The remaining 80% (net load) must be met by storage. This definition of severe renewable drought comes from this study, https://www.sciencedirect.com/science/article/abs/pii/S0960148118302829?via%3Dihub, page 581 and Figure 2.

[12] An annual carrying charge rate reflects return of and on capital. It is currently 11.8% in PJM. https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20230711/20230711-informational---market-efficiency-analysis-assumptions---july-2023.ashx

[13] https://www.energy.ca.gov/sites/default/files/2023-10/CEC-500-2023-055-D.pdf, page 44.

[14] https://efiling.energy.ca.gov/GetDocument.aspx?tn=254463, page 13.

[15] https://www.eia.gov/outlooks/aeo/supplement/excel/suptab_54.22.xlsx, focusing on the generation sector average component around $0.10/kWh, and average total end-use prices around $0.20/kWh. Other EIA data suggest a higher current end-use price around $0.25/kWh, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.

[16] https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy

[17] https://www.energy.ca.gov/sites/default/files/2024-01/CEC-500-2024-003.pdf, page 10.

[18] https://www.osti.gov/servlets/purl/1961845, Exhibit 4-6, page 26.

[19] https://about.bnef.com/blog/global-carbon-market-outlook-2024/

[20] https://www.eia.gov/tools/faqs/faq.php?id=74&t=11 $20/metric ton divided by 2,205 pounds/ton is $.009/pound which is $.009/kwh or $9/MWh.

[21] https://about.bnef.com/blog/global-carbon-market-outlook-2024/

[22] https://www.cnn.com/2024/05/10/world/video/largest-carbon-capture-factory-opens-vause-wurzbacher-intv-cnni-climate-or-business-fast

[23] https://www.osti.gov/servlets/purl/1961845, Exhibit 4-5 on page 25, averaging the all-in TASC $/kw for the two 95% capture projects. Transportation and storage of the carbon is projected by DOE/NETL to cost $3.7/MWh, Table 4-6, page 26, which for 5,328,000 MWhs per year is a small cost of about $20 million per year. Another DOE retrofit study is here, https://www.energy.gov/sites/default/files/2024-04/OCED_Portfolio_Insights_CC_part_i_FINAL.pdf

[24] https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={00AE3887-0000-C24C-BFC6-45EC1209A3DB}&documentTitle=20233-194396-08, Table 1, making reduction from the California project $6,000,000/MW to $1,900,000/MW (converting kW to MW).

[25] https://energy.mit.edu/wp-content/uploads/2022/05/The-Future-of-Energy-Storage.pdf, page 37.

[26] https://bloximages.newyork1.vip.townnews.com/richmond.com/content/tncms/assets/v3/editorial/d/9a/d9a0675e-5728-11ee-bf01-0b2aed23d7a9/650a00e698fe7.pdf.pdf. Pdf page 29.

[27] Dutch saying, c. 1937, https://quoteinvestigator.com/2013/10/20/no-predict/.

FERC/Federal News

FERC Watchers Digest Order 1920 and Forecast its Future

By James Downing

The ultimate future of FERC *Order 1920* depends on rehearing, implementation and inevitable litigation, but after reading through the order itself in the past week, many stakeholders see it as an important step forward in expanding the grid.

FERC issued the 1,364-page order on a 2-1 vote May 13, with Commissioner Mark Christie (R) filing a *dissent* and countered by a *joint concurrence* from Chair Willie Phillips (D) and Commissioner Allison Clements (D). (See *FERC Issues Transmission Rule Without ROFR Changes, Christie's Vote*.)

The order requires regional transmission planners, including ISOs and RTOs, to plan at least 20 years ahead of time using multiple scenarios while taking into consideration several benefits. Their cost allocation plans for projects must ensure only customers who receive those benefits pay for the projects.

"The status quo is not working, and this stuff is hard," former FERC Chair Neil Chatterjee (R) said. "I think that Commissioner Christie raised a lot of significant points in his dissent that I need to think through. I think he's probably right on a lot of it. But the reality is, somebody's got to make a tough call. And I commend Chairman Phillips for making the tough call here."

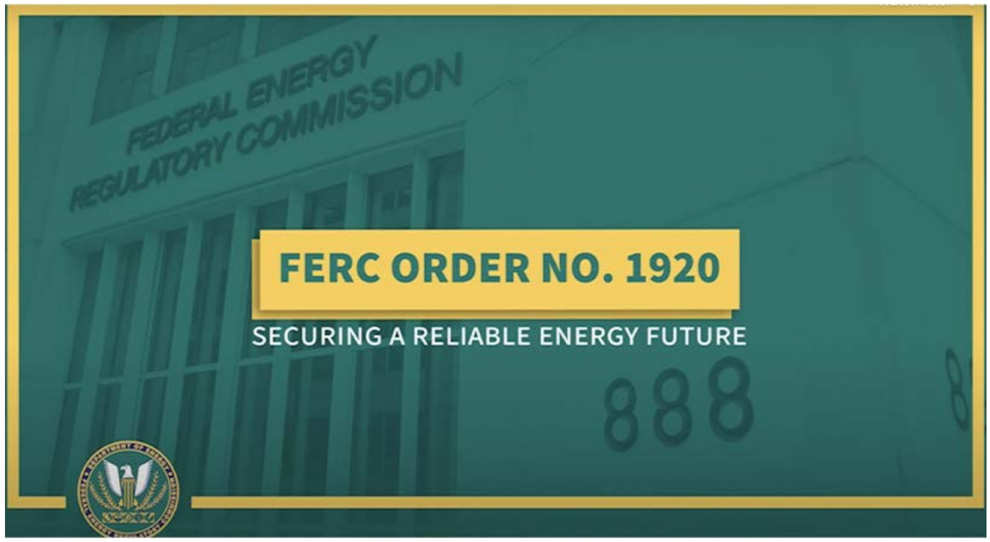
Chatterjee said the issue has bounced back and forth between Congress and FERC, and one of the two needed to act to move the ball forward.

"It's a 1,300-page order; there is a lot to unpack," Chatterjee said. "But from what I know of it to date, I honestly believe had I still been on the commission, I would have voted for it."

Outside of claims that the order is aimed at implementing President Joe Biden's green energy policies, much of Christie's concerns have to do with the impact on consumers. Devin Hartman, of the conservative think tank R Street Institute, argued that consumer response to FERC's rule would determine how far his arguments go.

"The big thing will be whether the consumers see the proactive and more comprehensive benefits approaches as leading to more economical transmission development than the status quo," Hartman said.

Regional economic transmission projects have generally done well on the cost-benefits front, saving consumers plenty of money, but consumers have been against the general rise in transmission rates, as most spending in recent years has gone to local projects that address specific reliability needs, he added.



| FERC

The National Association of Regulatory Utility Commissioners *expressed* disappointment with "the significantly diminished state role" envisioned in Order 1920. But the organization represents 50 states, and some of them are supportive, *such as* Michigan Public Service Commission Chairman Dan Scripps.

"You're going to have a trade-off any time you do interstate infrastructure planning on a consistent basis across state lines; you're going to gain more efficiencies, but you're going to lose some autonomy of those states," Hartman said.

The Electricity Consumers Resource Council, which represents large industrial customers and is "resource-neutral" in outlook, found the rule to be generally positive for consumers, said CEO Karen Onaran.

But Onaran's predecessor, Travis Fisher, who is now with the Cato Institute, wrote a *critical take* that argued Order 1920 represents FERC putting its thumb on the scale to help build out renewables.

It is unfortunate that the partisan politics around green energy have "hijacked" the transmission issue because the grid needs to be expanded regardless, Onaran said.

"I think for the Republican side, we just need to emphasize — especially as industrials are looking to expand their operations onshore in the U.S. — we're going to need reliable service," Onaran said. "And we're going to go to those regions that have favorable regulatory policies that do look at expanding the grid that can support our operations, regardless of what the generation choices or availability is; we're just going to need to get access to a lot more energy."

Even when it comes to the grid's transition to more green power, Chatterjee said he sees the politics eventually working itself out.

"I do think in the coming years that we will get to a point where red supply is feeding blue demand," Chatterjee said. "Where you have a lot of this renewable capacity is in red states, and the demand for that clean energy is going to be in blue states. And I don't think I'm being naive about this; I think that will fundamentally alter the politics around climate."

While Chatterjee did not like how the Inflation Reduction Act was passed in Congress, it was good policy to onshore the supply chain for renewable energy, which should help make that future possible, he added.

How the Rule Will Change Cost Allocation

Supporters of the rule see little difference in transmission built for renewables, or that needed for reliability and economics.

"It's not any one driver behind it; it's multiple drivers," said WIRES Group Executive Director Larry Gasteiger. "And I think even if you exclude one of those drivers, you still have plenty of other things that are pushing the need for

FERC/Federal News

more transmission. There's going to be some overlap between some of them. If you build a line to deal with a clean energy mandate or integrating more renewables, you may wind up getting more resilience out of the system and enhanced reliability; you may be able to meet some increasing load needs."

That has already played out, with the lines New Jersey is paying for under FERC Order 1000's State Agreement Approach to interconnect its initial tranche of offshore wind farms, Abraham Silverman, of SilverGreen Energy Consulting and a former state Board of Public Utilities staffer, said in an interview.

"When PJM did the modeling for the State Agreement Approach that New Jersey ultimately selected, they determined that they were benefits in ... three other states," he added.

Under the currently effective transmission planning and cost allocation regime in PJM, no other option is available, and New Jersey will have to pay for all of those transmission lines despite benefits flowing to other states. Order 1920 requires PJM to plan for binding state policies like New Jersey's offshore wind targets.

"Now there's an option on cost allocation, which is if the project meets certain benefit-to-cost ratios, then the costs are socialized across the entire grid," said Silverman. "If the proposed project doesn't meet the 1.25 benefit-to-cost ratio, then states can get together and voluntarily allocate those costs."

States will have a chance to decide how such lines are allocated, but Silverman said that if they were to just stick to the current SAA, then the commission could reject that because it would leave beneficiaries that are paying nothing.

"Now, they're only required to pay up to the benefits that they receive, and we're not talking carbon benefits, or anything else," Silverman said. "We're really talking production cost; reliability; other sort of very tangible benefits."

Grid Strategies President Rob Gramlich likened the dispute between the three commissioners on cost allocation to getting the check after group dinner.

"The way I think it's easiest to think about is if you're at a restaurant, should you pay for what you eat, or should you pay only for what you ordered?" he said on a webinar with reporters. "And one commissioner thinks you should only pay for what you ordered. And ... the majority said, 'No, you have to pay for what you eat.' And it's really just that very basic principle."

Part of the reason the majority allowed regional planners like RTOs to file their own cost allocation rules that could even overrule the states is because legal precedent from a 2002 case, Ari Peskoe, director of Harvard Law School's Electricity Law Initiative, said in an interview.

"Basically, the Federal Power Act is written in such a way so as to give transmission owners the right to file any changes in their rates," Peskoe said. "And so, FERC was concerned that if it gave the state regulators equal rights, it might be infringing on the utilities' rights to file rate changes."

Commissioner Christie argued that legal precedent would not be a problem in litigation if states got the right to file cost allocation rules of their own. Peskoe said he agreed with that interpretation.

While that would mark a big change for PJM and some other markets, Brattle Group Principal Johannes Pfeifenberger said that MISO's Multi-Value Projects have proved very popular even with red states in its footprint.

"MISO did a good job explaining how their states benefit from the Multi-Value Projects, and then has also shown that the portfolio of projects they have come up with benefits each state more than the postage-stamp cost allocation," Pfeifenberger said.

How Far Will Regions Take the Rule?

One open question is how the rule will be implemented in different regions.

Order 1000 required changes to transmission planning and cost allocation around the country, but only some regions effectively used it to cooperatively build out their grids.

"FERC can take the horses to the water but can't make them drink," Pfeifenberger said. "How the regions respond to it will be different, no doubt. And some of them will take this as an opportunity to really improve the planning process to create low-cost transmission solutions. And other regions will just comply with the letter of the order and implement processes on paper that don't really do anything in the real world."

The regions are going to have a lot of discretion to implement the rule, which is the case for nearly every major FERC rule, said Silverman.

"How you quantify benefits is going to be something that each individual public utility transmission provider is going to have to do," he said. "How you incorporate some of the more discretionary pieces of state policies into the transmission planning — the scenario-building process is going to be absolutely key. And then, of course, at the end of the day, you are only as good as the desire to build new transmission."

The rule gives regions more tools in the toolbox, but it does not necessarily require their use, he added.

Former FERC Chair Jon Wellinghoff (D), who ran the commission when it issued Order 1000, agreed that it was time for an update to its transmission rules.

"FERC just needs to ensure ... that those rules are adequately drafted so that there is clear direction to the ISOs as to what they should be doing," Wellinghoff said. "I mean, FERC has tremendous power there."

The chair can convene the ISOs and RTOs and other regions and explain what the commission expects to see as its rule is implemented, he added.

Wellinghoff also argued that FERC needs to ensure that Order 2222 is fully implemented alongside Order 1920, as the growth in electric vehicles and other distributed energy resources needs to be fully accounted for. With millions of EVs hitting the road in the coming years, FERC needs to get that rule right so they can be an asset to the grid instead of a burden on it, he said.

Rehearing and Appeal?

A rule this far reaching is going to have requests for rehearing, likely even from parties who largely support it but want to see something changed.

For example, while WIRES supports the planning and cost allocation changes, Gasteiger said it was disappointed that the final rule did not go as far on reinstating the federal right of first refusal as the proposed rule did.

Christie's dissent lays out a "great roadmap" for parties who support his position to follow on appeal, Chatterjee said.

One major issue on appeal is which circuit court gets the case, noted Harvard's Peskoe. Opponents of federal rules like to go to the 5th U.S. Circuit Court of Appeals in Texas because it has handed down decisions against Biden administration policies previously, he said. But to get it appealed to a specific circuit, opponents need to find an appropriate party located in its territory.

Most FERC cases are adjudicated in the D.C. Circuit Court of Appeals, and the commission

FERC/Federal News

would likely prefer it there as the judges have experience with the issues, Peskoe said.

Another major issue is the changing precedents in federal courts, with the Supreme Court considering cases that could overturn the *Chevron* doctrine of deference to "expert agencies," which is how the D.C. Circuit upheld Order 1000. (See *Supreme Court Hears Oral Arguments on Overturning Chevron*.)

"So, it's possible that the litigants will attack first authority in this case, use this rule as vehicle for a broader attack on FERC that could undermine flexibility to regulate utilities going forward," Peskoe said.

Christie raised the *Chevron* issue in his dissent, and he also argued that FERC's rule went against the newer "major questions doctrine" that came out of *West Virginia v. EPA* (which was argued by FERC nominee Lindsay See, solicitor general of West Virginia).

Litigation against FERC rules of this size and scope is almost a "rite of passage," Americans for a Clean Energy Grid Executive Director Christina Hayes said on a webinar hosted by the American Council on Renewable Energy. Order 1920 is built on nearly 30 years of precedent dating back to Order 888 that have opened up the grid and led to significant cost savings for customers, enhanced resource adequacy and other benefits, she said.

"This is built on very stable ground in that there's so much significant precedent supporting it," Hayes said. "Were this to be overturned, it would really remake the electrical industry and in ways that are hard to contemplate. For that reason, for the stability of the system, I imagine that there are significant forces that would support upholding this rule." ■

FERC/Federal News

FERC Forecasts High Temperatures, Flat Prices for Summer

By James Downing

This summer should bring high temperatures and electricity demand, but flat prices as cheaper fuel offsets higher load, according to FERC's *Summer Energy Market and Electric Reliability Assessment*, released May 23.

The National Oceanic and Atmospheric Administration forecasts a 60 to 70% likelihood of above-normal temperatures in June, July and August across the country compared with the 30-year average.

"High temperatures that are widespread can intensify stressed conditions on the electric grid by creating high electricity demand across a wide geographic area and reducing the availability of imported electricity from neighboring systems because they are also experiencing high demand," the report said.

Following last summer's "El Niño" weather pattern, the National Weather Service says there is a 69% chance that a La Niña could emerge this summer. For the U.S., a La Niña means more storms in the center of the country and less precipitation in the South; it can also lead to more Atlantic hurricanes.

NOAA released its hurricane *forecast* May 23 as well; it predicts an 85% chance of an above-normal season, with 17 to 25 named storms, eight to 13 forecast to become hurricanes, and four to seven of those to be major hurricanes. Forecasters have a 70% confidence in the ranges.

Despite expectations for a hot summer, electricity prices are forecast to be flat or slightly lower than in 2023. The one exception is the Northeast, where regional natural gas prices could mean higher power prices than last year.

FERC is forecasting average ISO-NE prices to be almost $10/MWh higher than last year, while those in CAISO are expected to fall by $23 to $34/MWh.

U.S. installed generation capacity is expected to hit 1,207 GW, up 40 GW from 2023 because of additions of wind and solar, while retirements were dominated by coal capacity, with 3.3 GW retiring through September.

ERCOT leads with 20.1 GW of capacity additions, including 12 GW of solar and 4.5 GW of batteries. CAISO is expected to add 8.9 GW overall, but it beats ERCOT, with 5.1 GW of battery capacity additions.

Summer is the season with the highest use of natural gas for the sector, with power burn expected to peak in July and August at 47 Bcfd this year.

"Natural gas used to generate electricity — or power burn — is expected to average 43.5 Bcfd in summer 2024, equal to power burn in summer 2023 but up 9.5% compared to the five-year average," the report said.

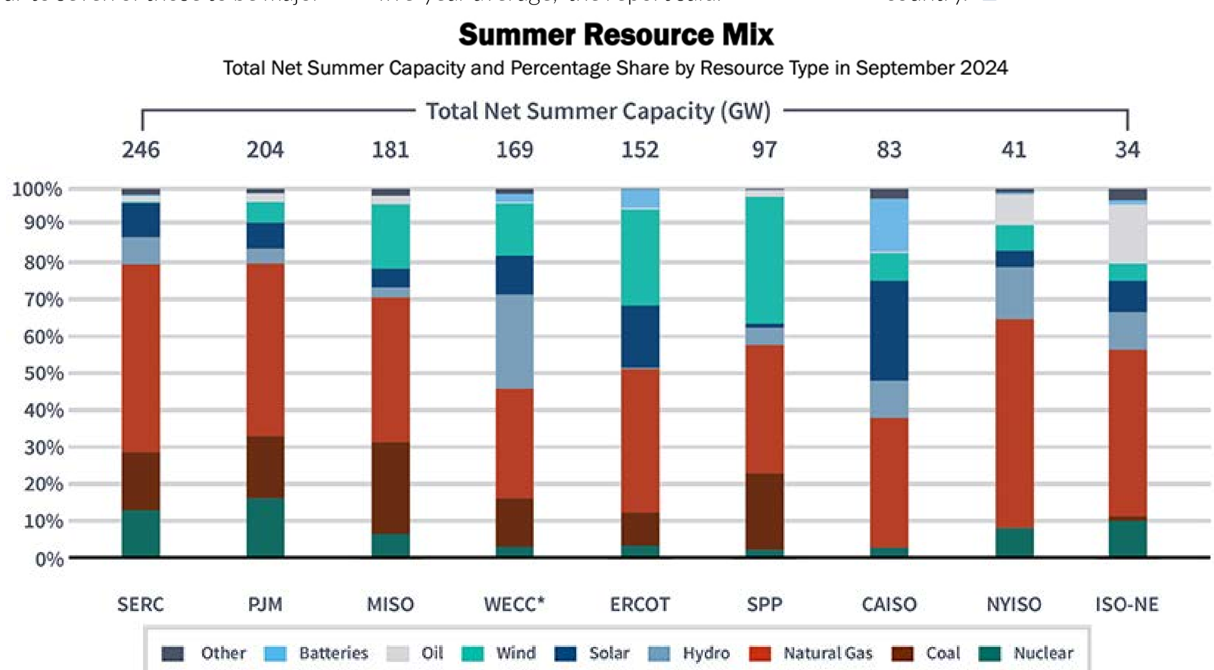
Coal stockpiles at power plants are higher this year, and coal delivery over the rail network does not face the same issues as the pandemic years from 2020 to 2022, but the Francis Scott Key Bridge collapse in Baltimore has impacted some local coal plants.

"Coal power plants nearby may experience delays or disruptions to resupply coal stocks via water (barges) if there is protracted disruption to shipping in nearby waterways to clean up the bridge collapse," the report said. "The bridge collapse temporarily halted coal deliveries by barge to the Brandon Shores and Wagner coal plants, totaling 1,865 MW, which are located directly adjacent to the bridge."

Baltimore is the second-largest port for coal exports, shipping the commodity from Appalachia to global markets and representing 28% of exports. That traffic was temporarily delayed because of the bridge collapse.

The Energy Information Administration is expecting demand to be 2.7% higher this summer than last year and 4.4% over the average of the past five summers.

"The expected larger electricity consumption this summer results from forecasted warm weather and strong economic growth," the report said. "Another significant source of electricity consumption growth is the construction of new data centers in many regions of the country." ■



A graph from FERC showing the fuel mix in different regions this summer. | *FERC*

FERC/Federal News

EEI Sues EPA over Power Plant Rules' Carbon-capture Requirement

By James Downing

The Edison Electric Institute has joined the litigation against EPA's power plant rules under Clean Air Act Section 111, filing its own petition to review the rules and intervening in existing suits.

The agency had already been sued over the rules by a group of states and the National Rural Electric Cooperative Association, the latter of which has asked the court to stay implementation of the rule. (See *Republican-led States Sue EPA over Power Plant Emissions Rule*.)

The rules imposed stricter emissions limits on existing coal plants and new natural gas plants. They identified carbon capture and storage as the best system of emission reduction (BSER) under the CAA. Coal plants intending to operate past 2039 will have until Jan. 1, 2032, to cut their emissions to a level based on a presumption that they will install a CCS system capable of capturing 90% of their emissions. (See *EPA Power Plant Rules Squeeze Coal Plants; Existing Gas Plants Exempt*.)

EEI CEO Dan Brouillette said in a statement that the investor-owned utility trade group still supports EPA's ability to regulate greenhouse gases under the CAA but opposes the use of CCS as the BSER.

"We are intervening today to preserve our ability to defend, if needed, elements of the final 111 rules that are consistent with the ongoing clean energy transition and that do not create reliability impacts for customers," Brouillette said. "At the same time, we are seeking judicial review of the agency's determination that carbon capture and storage should be the basis for compliance with other portions of the 111 rules. EPA's record and the docket do not support the agency's finding that CCS is adequately demonstrated for broad deployment across our industry."

CCS is an emerging technology, and the rule's implementation timelines do not align with its commercial reality, Brouillette said. No power plants are operating today that would meet the agency's requirements for CCS.

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"Throughout the rulemaking process, we repeatedly raised concerns that CCS is not yet ready for full-scale, industrywide deployment, nor is there sufficient time to permit, finance and build the infrastructure needed for compliance by 2032," he added.

EEI said its members are investing in CCS and other technologies that can deliver power around the clock and without emissions, but it cannot bet the future on a technology that is not ready for industrywide deployment.

The utility group's concerns about CCS are not unique, with SPP and PJM both recently saying the technology was not ready. (See related story, *SPP Shares Concerns over EPA's GHG Rule*.)

In a *statement* this month, PJM noted that EPA had responded to concerns it brought up in joint comments filed with SPP, ERCOT and MISO before the rules came out, making some helpful improvements. However, the final rules' reliance on CCS was still a concern.

"The availability of CCS is highly dependent on local topology, such as salt caverns available to sequester carbon and the availability of a pipeline infrastructure to transport carbon emissions from individual generating plants to CCS sites potentially hundreds of miles away," PJM said. "There is very little evidence, other than some limited CSS projects, that this technology and associated transportation infrastructure would be widely available throughout the country in time to meet the compliance deadlines under the [rules]."

Advanced Energy United put out a statement urging the broader electricity industry against litigation in response to EEI's petition for review.

"With the Inflation Reduction Act at our backs, and clean energy the most affordable and reliable choice, it's time for all of us to lean into the energy transition," said CEO Heather O'Neill. "Dragging our feet and betting against America's technological innovation will only drive up utility bills for consumers. The most cost-effective way to power our electric grid is by scaling up the use of the proven, clean and reliable technologies we already have."

Technologies like wind, solar, energy storage, geothermal, demand flexibility and efficiency are proven, clean alternatives to fossil-fueled power plants, United said. ■

FERC/Federal News

Manchin not Ready to Give up on Bipartisan Permitting Bill

Senate ENR Hearing: 24/7 Dispatchable Power Needed for Data Centers, AI

By K Kaufmann

Featured speakers at the hearing were (from left) Benjamin Fowke III, AEP; Karen Onaran, Electricity Consumers Resource Council; Scott Gatzemeier, Micron Technology; and Mark P. Mills, National Center for Energy Analytics. | *Senate ENR Committee*

Sen. Joe Manchin (D-W.Va.) | *Senate ENR Committee*

Sen. Joe Manchin (D-W. Va.) is not ready to give up on getting permitting legislation out of the Energy and Natural Resources Committee and to the chamber's floor, he said in his opening remarks during a May 21 hearing on the opportunities and risks of growing electricity demand in the U.S.

Approved May 13, FERC's long-awaited Orders 1920 and 1977 address regional transmission planning and the commission's backstop permitting authority but will only "help with one aspect of one part of a bigger set of grid permitting problems," said Manchin, who chairs the committee. "They are a Band-Aid on congressional inaction." (See *FERC Issues Transmission Rule Without ROFR Changes, Christie's Vote*.)

Sen. John Barrasso (R-Wyo.) | *Senate ENR Committee*

Manchin said he has been working with Sen. John Barrasso (R-Wyo.), the committee's ranking member, on a permitting bill, and "we finally have language. We want to start sharing that language with everyone [so] that people can see where we are and hopefully that we can get our act together."

Accelerating permitting was one of several familiar themes raised at the hearing, which primarily served as an echo chamber for the argument that meeting rising electricity demand from new factories and data centers across the U.S. will require not only keeping existing coal- and natural gas-fired power plants online, but also building more.

EPA's recent rules on cutting carbon emissions from existing coal and new natural gas plants were a particular target for both Manchin and Barrasso, who represent major coal-producing states. Already facing legal challenges from a group of Republican-led states and an industry trade association, the rules could require coal-fired plants without some form of carbon capture to close by 2039. (See *Republican-led States Sue EPA over Power Plant Emissions Rule*.)

"These plants play a major role in ensuring electric reliability," Barrasso said. "They also make electricity more affordable. President Biden doesn't seem to care at all. He wants the cost of complying with EPA rules to be high. He wants to force operators to shut down these plants before the end of their useful life. It is a disgrace. We cannot regulate our way to more electric generation."

That additional generation is needed, Barrasso said, to keep the U.S. ahead of China in the emerging competition for dominance in artificial intelligence. China is continuing to build coal-fired plants to power its data centers, while the U.S. is closing down plants. "The president's opposition to coal, to natural gas and even to hydropower … is a white flag. It is … an act of surrender to China," he said.

Both lawmakers also pointed to NERC's recent summer assessment warning that extreme heat waves could put reliability at risk in some regions. (See *NERC's Summer Assessment Sees Some Risk in Extreme Heat Waves*.)

Witnesses at the hearing generally provided variations on the same core themes: the need for reliable power to meet increased demand and rising concerns that the U.S. grid will not be able to deliver.

To a certain extent, the U.S. electric system has fallen victim to the success of the Infrastructure Investment and Jobs Act, Inflation Reduction Act, and CHIPS and Science Act, all of which have catalyzed new investment in domestic industry and manufacturing, but also new demand, said Benjamin Fowke III, interim CEO of American Electric Power.

"Just a few years ago, a large industrial manufacturing facility might require 100 MW," Fowke said. "A facility that size would typically be one of a kind in a region, would be the major source of economic activity for that region. Now it is common for a single data center to require three [or] up to 15 times this amount of power for a single site."

Demand growth related to data processing could double nationwide in three years, he said. FERC, other federal agencies and state officials should collaborate "to evaluate the establishment of a central planning authority focused on reliability and directing FERC to ensure that viable reliability safety valve mechanisms are in place to prevent premature plan retirements," Fowke said.

FERC/Federal News

Congress should also work to expedite permitting of resources — "new 24/7 dispatchable and clean energy" — that utilities identify as critical for system reliability, he said.

Mark P. Mills, founder and executive director of the National Center for Energy Analytics, went further. "The fastest way to increase power supplies — because we're talking about demands that are occurring in the next few years, not decades — it's not things we don't know how to build, but things we know how to build," he said. "The best construction of dispatchable power will come from gas pipes and gas turbines. They'll be the primary source of new supply.

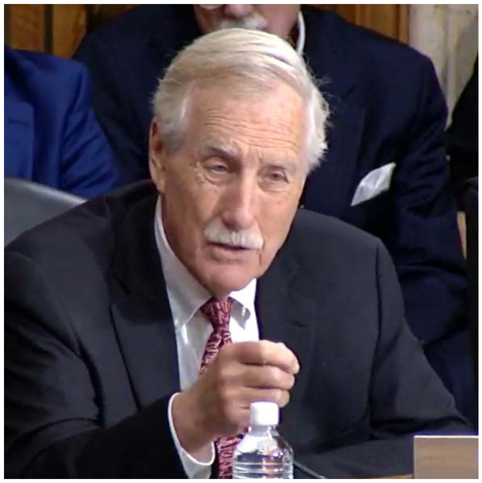
"This will be true with the United States, [in] almost every state; and it's also true in Europe. It's what's happening around the world, but especially here," he said.

The Cost of a Tow Truck

Speaking for big industrial power users, Karen Onaran, CEO of the Electricity Consumers Resource Council, said U.S. industry could need an additional 36 GW of power by 2030, which will require right-sizing the grid and reducing regulatory barriers. She also criticized EPA's power plant rules, saying they "further complicate a tenuous situation on our grid," impeding access to affordable and reliable energy, she said.

"We cannot afford to take any options off the table right now," Onaran said. "We need all-of-the-above resources, and we need the infrastructure to support those resources. We need an agile and flexible grid that can manage variable supply, as well as variable demand. Demand is going to change [its] profiles."

Scott Gatzemeier, corporate vice president



Sen. Angus King (I-Maine) | *Senate ENR Committee*

for front-end expansion at Micron Technology, spoke of the memory chip maker's need for firm, 24/7 power and its efforts to reduce its power demand as it builds out new capacity for energy-efficient chips in New York, Virginia and its own home state of Idaho.

The company's site in Onondaga, N.Y., is 40 miles north of a nuclear power plant "with a direct line connection to a 345-kV substation across the street from [our] site," Gatzemeier said. "Reliability of the system is incredibly important [for] semiconductor fabs because a small millisecond blip in our power would take down our factory for up to a week by interrupting processing."

For its Idaho facility, Micron is waiting for Idaho Power's Boardman-to-Hemingway transmission line, which will allow bidirectional flows of clean power — hydro and wind — with the rest of the Pacific Northwest. The project has been in development and permitting since 2007 and is now waiting for final federal and state notices to begin construction, according to a *project timeline* on Idaho Power's website.

At the same time, Micron has committed to use 100% renewable power at its U.S. factories by the end of 2025. Gatzemeier said in his written testimony that its customers are always pushing it for more energy-efficient chips. Customers are reporting that Micron's most recent memory chip, designed for AI, uses 30% less energy.

One of the last senators to speak, Sen. Angus King (I-Maine) said the hearing's discussion was missing the critical role of climate change in the energy transition.

"We're only talking about half the equation," King said. "We're like in a car on a railroad track with a train coming toward us, and we're talking about the cost of a tow truck. The cost of not addressing climate change dwarfs the cost of addressing climate change. …

"To act like the transition is just something we're doing because it's a nice thing to do or because some elite group says we should do it is just not accurate."

From grid-enhancing technologies to pumped hydro storage to old-fashioned conservation, other options exist for meeting increased demand, he said, but permitting reform will be the key.

Speaking to reporters May 13, Senate Majority Leader Chuck Schumer (D-N.Y.) said he had told Manchin he did not think permitting reform would go anywhere in the current Congress. "I think it must go somewhere," Manchin countered May 21. "We have it ready to go, and we will … see if we can move this from this committee forward on the floor." ■

FERC Upholds Tri-State Exit Fee Calculation Method

Clarification Granted on Transmission Credit Amortization

By James Downing

FERC on May 23 upheld the contract termination payment (CTP) rules for Tri-State Generation and Transmission Association it approved last year, though it modified some of its original order in response to requests for clarification (*ER21-2818-002, et al.*).

The commission ordered Tri-State to implement a balance sheet approach for the CTP and a new transmission crediting approach that includes transmission-related debt. (See *FERC Picks 'Balance Sheet Approach' Exit Fee for Tri-State Members*.)

Tri-State is a wholesale generation and transmission cooperative that serves members in Colorado, Nebraska, New Mexico and Wyoming with long-term, full-requirement wholesale electric service contracts.

FERC's preferred balanced approach was initially proposed by one of Tri-State's members. The co-op argued for its preferred accounting methods on rehearing, but FERC declined to overhaul its December order.

"We continue to find that the adopted BSA is consistent with principles of cost causation and with the purpose of an exit fee," FERC said. "The presiding judge correctly explained that the BSA appropriately aligns costs and benefits to Tri-State members by declining to assign generation-related debt to Tri-State's members located in the Eastern Interconnection, whose loads are supplied entirely through power purchase agreements."

FERC also continued to find the BSA's treatment of PPAs is just and reasonable because it requires that members pay their *pro rata* share of those that are actually used to serve load.

Tri-State argued that assigning the costs of dozens of PPAs to departing members would be unworkable, which did not persuade FERC. The commission said the co-op does not need to provide members with their exact share of PPA costs before they make a final decision on departure.

FERC granted requests for clarification from Tri-State and Mountain Parks Electric on the amortization term for the transmission credit. It should be amortized over the remaining term for the depreciation rates in effect for the assets to which the debt payment relates, the commission said.

It also clarified that the amortization term for the credit is determined based on the average remaining life of depreciable transmission plant base as determined by Tri-State's most recent Form No. 1 filing at the time a member withdraws.

The commission sustained the overall transmission crediting approach, finding the prepayment and back-crediting of transmission-related debt in the adopted BSA strikes a reasonable balance between ensuring the debt-related costs of Tri-State's transmission assets are recovered through the CTP and ensuring the withdrawing member reaps the full benefit of these costs while minimizing cost shifts.

"The payment of transmission-related debt as part of the CTP is intended to compensate Tri-State for the transmission-related debt it incurred to serve withdrawing members," FERC said. "To prevent shifting costs onto remaining members, the withdrawing member must compensate Tri-State for this debt whether it uses Tri-State's system or not." ■

Tri-State's headquarters in Westminster, Colo. | *© RTO Insider LLC*

CAISO/West News

Glick, Christie Clash over States' Role in FERC Order 1920

By Ayla Burnett

VAIL, Colo. — Former FERC Chair Richard Glick faced off with his old colleague, Commissioner Mark Christie, over FERC Order 1920 in the general session of the Western Conference of Public Service Commissioners' annual summit May 21.

The order, which directs regional transmission planners to alter their processes to be more forward-looking and proactive, stemmed from a Notice of Proposed Rulemaking issued in 2022 under Glick's leadership and with Christie's enthusiastic support because of its consideration of state input. But Christie dissented from the order, which didn't contain the provisions that had led to him voting for the NOPR. (See *FERC Issues Transmission Rule Without ROFR Changes, Christie's Vote*.)

"The NOPR gave states a very significant role, particularly in the key functions of the selection criteria for determining what projects go into the regional plan," Christie said. It also gave states the ability to choose benefits, of which the rule outlines seven, that are key in determining who pays for transmission.

"The rule actually mandates benefits, which NARUC [the National Association of Regulatory Utility Commissioners], specifically in their comments, said, 'Don't mandate benefits; let each region decide what works for them.' The rule went in the opposite direction," Christie said. "And of course, the most important issue of all is cost allocation. The NOPR promised that states would consent. … That was critically important to NARUC; it was critically important to every state organization; and it was critically important to me."

Order 1920 gives states six months to agree on a cost allocation mechanism with regional transmission planners, who must come up with a default *ex ante* method. Departing from the NOPR, regional planners are not required to file any agreement with the states or even any state proposals as alternatives.

"What this rule does is leave states in the position of just being a stakeholder," Christie said.

But Glick defended the order and expressed uncertainty about the role of the six-month timeline, which, according to Christie, would be "extraordinarily difficult" for states to reach an agreement in.

"Heck, I don't know if six months is too long or too short, but at least there's an opportunity to get together," Glick said. "The states have an opportunity in this engagement process to come up with a state agreement cost allocation approach and process."

Christie also took issue with elimination of the FERC Order 1000 cost allocation principle 6, which held that transmission providers could have a different allocation process for public policy projects. In Order 1920, all projects are in the same bucket, "which is going to make it extremely difficult in the real-world practical application determining how much of a cost in one of these long-term projects is actually public policy," Christie said.

Glick emphasized that the benefits are for the purpose of project selection, not for the purpose of allocating transmission costs.

From left: FERC Commissioner Mark Christie, former FERC Chair Richard Glick and Vincent Duane, Copper Monarch | *© RTO Insider LLC*

'Massive Wealth Transfer'

Mandating benefits and minimizing state consent over cost allocation will be problematic for the consumers who will bear the burden of transmission costs, argued Vincent Duane, principal at Copper Monarch and former general counsel for PJM. He joined Glick and Christie on the panel.

"The way this rule is drawing a lot of criticism, and in my opinion rightly so, is that it does potentially represent a massive wealth transfer away from generation developers … and picked up by customers," Duane said.

Christie agreed. "This rule is absolutely about a massive transfer of wealth from consumers to developers, no question about it," he said.

Glick again pushed back, saying the rule will ensure that costs can only be allocated to customers to the extent they benefit.

"It's not a wealth transfer," he said. "The customers are only going to have to pay where they benefit."

To ensure protection of consumers, Christie said state regulators should have a more robust role than the order gives them.

Duane boiled the conversation down to weighing the inevitable compromises that will be made as Western electricity markets expand and utilities and power providers decide which day-ahead market to join.

"There's going to be some degree of surrendering of state sovereignty as a result of regionalizing. … There's going to be some potential that you're going to be told you're a beneficiary when you may not feel you're a beneficiary," Duane said. "As state policymakers, the question you're facing is, do the benefits of being a part of a regional organization that plans regionally across multiple jurisdictions — that requires some give and take, and some rough and tumble, and some unscientific, at the end of the day, benefits and costs — is it worth it?" ■

CAISO/West News

Is NV Energy Leaning to CAISO's EDAM?

Utility Exec Points Positively to CAISO Response to Pathways Initiative

By Robert Mullin

An NV Energy executive has provided the strongest public indication yet that the Nevada utility is poised to choose CAISO's Extended Day-Ahead Market (EDAM) over SPP's Markets+.

Dave Rubin, federal energy policy director at NV Energy, offered the insight May 22 at a joint session of the CAISO Board of Governors and Western Energy Imbalance Market (WEIM) Governing Body.

A member of the West-Wide Governance Pathways Initiative's Launch Committee, Rubin spoke during the committee's presentation on the initiative's proposal to alter the governance structure of CAISO's WEIM and — by extension — the EDAM, which will extend the capabilities of the real-time WEIM.

Step 1 of the Pathways proposal calls for the WEIM's Governing Body to assume "primary" authority over WEIM/EDAM matters, elevating its power from the "joint" authority it currently shares with the CAISO board over such matters. The move represents the limit of ISO governance changes that can be made under current California law, according to legal analysis performed for the Pathways Initiative. (See *Western RTO Group Floats Independence Plan for EDAM, WEIM*.)

Step 2 of the plan seeks to create "a durable governance structure with a fully independent board that has sole authority to determine the market rules for EDAM and WEIM," which will require changes to California law, something Pathways Initiative backers are pursuing through engagement with the legislature. (See *Pathways Initiative to Act Fast on 'Stepwise' Governance Plan*.)

In speaking at the May 22 meeting, Rubin said Step 1 "inspires confidence, not only for moving to a form of solid independent authority at some point over the EDAM and EIM in Step 2, but also for the continued engagement of the [Pathways] parties as we expand market services for the benefit of our customers."

Rubin said NV Energy has been impressed by the "engagement and encouragement" around Step 1 and the Pathways Initiative by CAISO's staff and board and the WEIM's Governing Body that "we believe demonstrate a common understanding of the importance of independent market governance."

"It's certainly one thing to discuss that as a goal, but it's far more meaningful to take concrete actions to further that objective. And accordingly, for NV Energy, we've strongly supported the work of the Launch Committee, and it clearly helps inform our market evaluation," he said.

NV Energy's ON Line | *WW Clyde*

While Rubin's comments fell well short of an announcement in favor of EDAM, they came during a week when multiple electricity industry sources in the West told *RTO Insider* that NV Energy officials have been circulating the idea that the utility plans to join the CAISO day-ahead market but probably won't make an announcement before filing with Nevada regulators.

The utility did not respond to a request for comment.

NV Energy in Key Position

An NV Energy decision in favor of EDAM would be pivotal for CAISO and the Pathways Initiative for at least two reasons.

First, because of its central location in the West, NV Energy's transmission network has been a key transit point for energy transfers — or wheel-throughs — among balancing authority areas of WEIM participants since it joined the market in 2015. It likely would continue to fulfill that vital function for the EDAM, while also hindering the ability of potential Markets+ participants in the Northwest and Desert Southwest from transacting freely with each other.

Second, the Pathways proposal stipulates that CAISO's filing of WEIM primary authority tariff changes with FERC wouldn't be triggered until EDAM obtains implementation agreements from a "set of geographically diverse" WEIM participants representing load equal to or greater than 70% of the CAISO BAA annual load in 2022.

The EDAM last month secured a full commitment from PacifiCorp and has received tentative — but solid — commitments from Balancing Authority of Northern California, Idaho Power, Los Angeles Department of Water and Power, and Portland General Electric. Given that, a utility of NV Energy's size and location would provide the trigger for CAISO to file the Step 1 change once it emerges from the ISO's stakeholder process.

A study published this year by The Brattle Group showed NV Energy could earn as much as $149 million in annual benefits as a member of EDAM versus a top-end benefit of $16 million in Markets+. (See *NV Energy to Reap More from EDAM than Markets+, Report Shows*.) ■

CAISO/West News

FERC Denies PacifiCorp Formula Rate Change

By Elaine Goodman

FERC on May 21 rejected PacifiCorp's request to include in its Open Access Transmission Tariff the interest it pays when refunding advance payments such as interconnection study deposits (*ER24-1595*).

In a March 22 *filing*, PacifiCorp described the interest payments as "prudently incurred costs."

The company noted that FERC Order 2023 requires interest to be paid on refunds of interconnection study deposits, commercial readiness deposits and payments in lieu of site control. PacifiCorp said its Large Generator Interconnection Procedures also include that requirement.

The deposits are refunded when an interconnection customer reaches commercial operation or withdraws from the interconnection queue, the company said. Interconnection study deposits are refunded after deducting study costs PacifiCorp paid for, while commercial readiness deposits are refunded less any withdrawal penalties owed. Site control deposits are fully refunded.

PacifiCorp asked to include the interest payments for those refunds in its Annual Transmission Revenue Requirement that is part of the OATT. And in response to comments during a previous proceeding, PacifiCorp said it would deduct from the interest expense the interest it earned while holding the deposits.

"The interest expense is a legitimate and required cost for PacifiCorp to provide interconnection service," the company said.

The filing drew protests from Bonneville Power Administration and a group of customers comprising Utah Associated Municipal Power Systems, Utah Municipal Power Agency, and Deseret Generation and Transmission Cooperative.

The Utah customers said PacifiCorp's proposal would inappropriately shift costs from generators seeking interconnections to transmission customers.

BPA said PacifiCorp hadn't been clear on how it would determine the interest expense, or explained why it should have discretion in calculating its interest income on the deposits.

BPA also argued that under a 2013 settlement that implemented a formula rate for PacifiCorp's transmission service, single-issue rate filings related to the formula rate are prohibited.

FERC rejected PacifiCorp's proposed formula rate revision, saying the company had not shown that its plan to recover interest expense on the deposits was just and reasonable.

"PacifiCorp has not demonstrated that its proposal would restrict the use of the deposit funds," the commission wrote. "Although PacifiCorp represents that it currently puts the deposit funds in short-term, daily rate interest-bearing accounts, the record in this proceeding does not indicate that PacifiCorp is required to do so."

While not addressing all of the protesters' objections, the commission said PacifiCorp hadn't fully explained how it would calculate interest expense.

PacifiCorp transmission line | *PacifiCorp*

According to its filing, PacifiCorp's interest expense in 2023 amounted to $15.1 million, which was offset by $9.4 million in interest earned on the deposits, for a net interest expense of $5.7 million. The rate impact of that expense would be about 1%, according to the company, which noted that the interest expense would vary each year.

PacifiCorp said it had tried to work with BPA and other customers on its interest-expense proposal. The company sent its proposed methodology to them in February and followed up with a conference call in March. ■

CAISO/West News

WCPSC Panelists: Forecasting Changes Needed to Address Uncertainty

Experts Call for Industry to More Closely Examine New Drivers Influencing Load

By Ayla Burnett

VAIL, Colo. — "Uncertainty" was a recurring theme at the annual meeting of the Western Conference of Public Service Commissioners last week, where participants grappled with how to account for the growing number of unknowns in resource adequacy modeling in a future with less predictable weather patterns and unprecedented load growth.

Some speakers at the meeting said the issue requires the electricity sector to fundamentally change its approach to load forecasting.

"There's a lot of climate and economic uncertainties," Siva Gunda, vice chair at the California Energy Commission, said during a panel May 20. "Do we really understand the climate data, and are we incorporating it into the forecast? Most of our work has been historically given — historic insights, historic weather patterns; obviously that's not true anymore."

The theme of uncertainty dominated conversations about RA, as industry experts shared both a fear of how changing conditions will affect the grid and an inspiration to address the unknown.

"The operational conditions on the system have become a challenge, and the need to harness the collective integration, diversity and power of the grid has never been more true," said Sarah Edmonds, CEO of Western Power Pool. "Several years ago, utilities … observed that we are, for lots of reasons, headed toward a real reliability pinch in the West."

Load growth was essentially flat for over a decade compared with today's "astronomical" load growth projections stemming from new data centers, widespread electrification, and other trends in technology, policy and economics, said FERC Commissioner Mark Christie.

These "macro drivers" should be considered in modeling and forecasting, rather than relying solely on historical data, according to Jeremy Hargreaves, principal at Evolved Energy Research. Other macro drivers include state emissions targets, decarbonization and electrification policies, artificial intelligence sector growth, and crypto markets.

"The question is how to proactively plan in the face of uncertainty. We want to be finding these no-regrets actions that we can take that are informed by these macro drivers, recognizing there's a lot of uncertainty in how these will play out," Hargreaves said. "We need more complex modeling approaches to try and estimate what kind of impacts they'll have."

Siva Gunda, Commissioner and Vice Chair at the California Energy Commission, speaks in a load forecasting panel at the Western Conference of Public Service Commissioners May 20. | *© RTO Insider LLC*

Gunda emphasized the importance of adequate forecasting to address uncertainty and maintain reliability.

"Forecasting has a direct implication on affordability; it has a direct implication on reliability; it has direct implications on economic and industrial processes. And so, what we're doing right or wrong will directly affect the entire system," Gunda said.

Forecasting should evolve to keep up with changing conditions and uncertainty, and Hargreaves and other industry analysts suggested supporting the grid with bottom-up forecasting and end-use forecasting, which looks at individual customer load geographically.

"My argument is that our historical approach to planning is not going to do," said Ry Horsey, researcher and software engineer at National Renewable Energy Laboratory. "Forecasts should inform planning and decision-making."

Evolved Energy Research has looked at a variety of different sectors and developed a load-growth taxonomy that reflects different loads and how they impact people over time, and Hargreaves suggested more widespread implementation of this model in forecasting.

Robert Kenney, president of Xcel Energy's Colorado division, summed up both the fear of uncertainty and the actions being taken to address it.

"I don't think there's any disagreement that we're retiring resources more quickly … we have load showing up in ways that we haven't seen in 20 years," Kenney said. "We should be freaked out, but only to the extent that it drives creativity and action." ■

ERCOT News

ERCOT Projects 97-GW Peak Demand by 2034

By Tom Kleckner

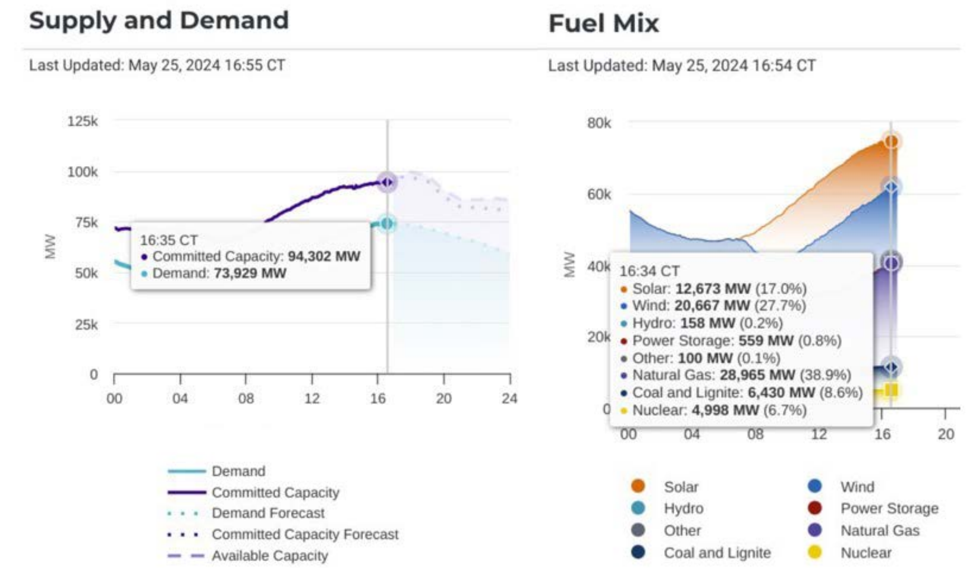
ERCOT's latest capacity, demand and reserves (CDR) report projects summer peak demand will increase to more than 97 GW by 2034, assuming normal weather conditions.

However, the weather has been anything but normal recently in Texas. ERCOT is coming off the second-hottest summer in state history, and it just set an unofficial peak demand record for May (77.13 GW) that exceeds the grid operator's *all-time peak* from 2018 (73.47 GW).

The heat index hit 113 degrees Fahrenheit in Austin on May 25 and has already hit triple digits in Houston, where the low temperature dropped to only 80 degrees on May 21. That is about a month and a half ahead of normal, according to a *local forecaster*.

The National Oceanic and Atmospheric Administration (NOAA) has predicted an "*above-average" hurricane season* this year, with between 17 and 25 named storms. It says "extraordinarily high, record-warm water temperatures" in the Atlantic Ocean, linked to climate change, are energizing the waters and fueling storm development.

NOAA said another factor influencing this year's hurricane season is La Niña, a climate pattern that cools surface ocean temperatures and lessens wind speeds, allowing more storms to develop.



Demand is already escalating in ERCOT's region with summer still a month away. | *ERCOT*

The *CDR report* forecasts peak demand of 83.29 GW this summer, assuming normal weather conditions. Demand is expected to exceed 84 GW in 2026, 86 GW in 2028 and 90 GW in 2030, according to the report.

Energy consultant and Stoic Energy principal Doug Lewin doesn't think that is enough. He says ERCOT still doesn't factor climate change into its projections, and he noted the ISO's current record for peak demand is 85.46 GW, registered last August.

"They only expected 73 GW this month and we've already passed that. Had this heat hit outside a holiday weekend, we'd likely be around 80 GW," he *said* on X, the social media platform formerly known as Twitter.

One Austin resident's weather projection for the summer. | *Emily Eby French via X*

ERCOT says its load forecasts are based on normal weather conditions and determined by the methodologies *posted* to its website. Staff forecasts scenarios through 2033 using a model with historical weather years.

The CDR report is designed to provide forecasted planning reserve margins (PRMs) for ERCOT's summer (June-September) and winter (December-February) peak-load seasons. The ISO says it is not intended to characterize the risk of scarcity conditions from a real-time operations perspective. It defines the PRM as the percentage of capacity above firm demand that is available to cover uncertainty in future demand, generator availability and new resource supply.

ERCOT's operational capacity exceeds 100 GW next year but increases to only 101.50 GW by 2033. However, the CDR report indicates the grid operator expects 30 GW of planned capacity by that same time, with solar resources accounting for 28 GW. ■

Texas Public Utility Commission Briefs

CenterPoint Energy Still Recovering from Damaging Derecho

CenterPoint's Jason Ryan briefs the PUC on restoration activities in Houston. | *Admin Monitor*

A CenterPoint Energy senior executive told Texas regulators May 23 that slightly more than 27,000 of its customers remain without power a week after a derecho devastated the Houston area with winds exceeding 100 mph.

Jason Ryan, CenterPoint's executive vice president of regulatory services and government affairs, said during the Public Utility Commission's open meeting that the utility remains in emergency operations.

"We understand that it's been a long seven days, that it's been in excess of 100 degrees in terms of the feels-like temperature and that we still have a lot of work to do," Ryan said. "We will work day and night until we finish the mission. We appreciate all of our customers and for sticking with us through this unprecedented event."

He said CenterPoint had only about 15 minutes to prepare for the derecho, which national meteorologists define as a continuous or intermittent path of severe wind from a squall line of thunderstorms. Derechos can extend at least 400 miles and at least 60 miles wide and generate hurricane-force winds.

About 922,000 CenterPoint customers were without power in the storm's aftermath. That number was down to fewer than 18,000 following the PUC meeting, according to CenterPoint's *performance tracker*.

Ryan thanked the more than 5,000 mutual assistance crews from other states that augmented CenterPoint's 2,000 crew members, noting they have not suffered any serious injuries or deaths.

"That's probably the proudest accomplishment that I can stress with you," he told the commissioners. "I look forward to sending these crews home just as safe as they arrived to help our communities."

The restoration crews replaced more than 800 miles of wires, more than 700 transformers and about 2,000 distribution poles. CenterPoint said in a *statement* it has also deployed 13 mobile generators to critical facilities, cooling centers, health care facilities, first responder locations, senior centers and schools.

"Everyone I've talked to has said you all have done an amazing job responding to an event that you couldn't really prepare for," PUC Chair Thomas Gleeson told Ryan. "I've heard nothing but good things."

Wearing a logoed polo shirt instead of his normal suit and several days' worth of stubble, Ryan said he was returning to CenterPoint's emergency operations center after his presentation. He said the company's headquarters in downtown Houston lost more than 500 windows; officials say it could be months before the business district's *windows are repaired*.

"While we don't know when we'll have access to our building again, it hasn't impaired our restoration efforts," Ryan said.

Loan Program Attracts Interest

PUC staff said they have received 10 completed commitments to apply for disbursements from the $5 billion Texas Energy Fund (TEF), which is designed to incent more dispatchable energy to the ERCOT grid. The proposed projects could add more than 4.9 GW of capacity (*56455*).

Applicants face a May 31 deadline to file notifications that they intend to apply for the funds. Formal applications can be submitted on or after June 1. The loans will be issued by Dec. 31, 2025.

The commission established the TEF in March because of *state legislation* passed last year. Qualifying projects must add at least 100 MW of dispatchable capacity to the grid. The PUC says the program can support up to 10 GW of new or upgraded generation capacity in ERCOT. (See *Texas PUC Establishes $5B Energy Fund*.)

NRG Energy accounts for three of the applications. The company *said* this year that it plans to use TEF loans to help finance construction of two new natural gas-fired plants that would be available in 2026.

Corona Named Executive Director

The commission announced it has promoted interim Executive Director Connie Corona to the official role. She fills the position vacated by Gleeson when he was appointed PUC chair in January. (See *Abbott Names PUC Executive Director as Chair*.)

"I don't think it could be any question you're the right person for this job," Gleeson told Corona.

Corona has spent 12 years at the commission, sandwiched around a 14-year stint in NRG's regulatory affairs department.

The PUC also promoted Chief Program Officer Barksdale English to deputy executive director. English joined the commission in 2018 after six years at Austin Energy. ■

— Tom Kleckner

ERCOT News

ERCOT Technical Advisory Committee Briefs

Measure on ECRS Deployment Passes on 4th Attempt

AUSTIN, Texas — ERCOT stakeholders plumbed the depths of Robert's Rules of Order and amended motions before endorsing a rule change May 22 that allows the grid operator to manually release ERCOT contingency reserve service (ECRS) from economically dispatched resources after repeated violations of the system power balance constraint.

Following multiple failed attempts, the Technical Advisory Committee finally met the two-thirds threshold for approval by lowering the nodal protocol revision request's (*NPRR1224*) offer floor from the originally proposed $1,000/MWh to $750/MWh. The measure passed 20-10, opposed by the consumer and retail segments over concerns of price increases.

The change introduces a trigger that ERCOT can use to manually release ECRS from security-constrained economic dispatch (SCED)-dispatchable resources when the amount of the power balance violation is at least 40 MW for 10 consecutive minutes. With TAC's modification, it would also require that energy offer curves for capacity assigned to ECRS be offered at the new floor.

ERCOT staff and the Independent Market Monitor have been collaborating on the issue since late 2023 after ancillary service methodology discussions for this year at TAC and the Board of Directors. The board directed staff to review the processes used to compute the minimum quantities of ECRS and identify potential alternatives by May.

The grid operator has been operating under a conservative posture since the 2022 summer. It has been procuring huge quantities of ancillary services to ensure it has enough operating reserves to account for intermittent solar and wind resources.

However, that has increased costs in ERCOT's energy-only market. The Monitor says ECRS, the newest ancillary product, created artificial supply shortages that produced "massive" inefficient market costs totaling about $12.5 billion last year through Nov. 27. (See *ERCOT Board of Directors Briefs: Dec. 19, 2023*.)

The Monitor suggested the deployment trigger to avoid sequestering large quantities of ECRS out of SCED that it said caused the mechanism to perceive shortages that weren't real and set energy prices much higher than their true marginal reliability value. It also proposed a re-evaluation of the ECRS procurement quantities and eliminating the $1,000/MWh offer floor.

"Such a provision would retain a significant portion of the artificial shortage pricing that we documented in 2023, mitigating only those prices that exceeded $1,000/MWh," the Monitor said in its *comments*. "While this may be in the economic interest of suppliers in the short term, setting prices that are not based on market fundamentals ... will undermine the credibility of the ERCOT markets over the longer term."


ERCOT's Matt Mereness briefs TAC on the real-time co-optimization plus battery project. | *© RTO Insider LLC*

Generation owners, led by Michele Richmond, executive director of Texas Competitive Power Advocates, and Lower Colorado River Authority's Blake Holt and ENGIE's Bob Helton, disputed the IMM's valuation of ancillary service reserves.

After first jokingly suggesting that the issue be placed on TAC's combination ballot, Luminant's Ned Bonskowski reminded members that ECRS was originally intended to be deployed with real-time co-optimization, which is still two years away.

"It's a tough problem where we're trying to bridge two worlds," he said. "We've got a lot of folks that are thinking about the extreme heat and scarcity that we had last summer and reacting to that, whereas I think the joint commenters looked at this and said, 'Well, while we may not agree that the way ECRS is currently operated is the problem, we recognize that there is a concern, and so as a step towards compromise, let's try to align whatever it is in NPRR2024.'"

Bonskowski shared data that he said indicated releasing 500 MW of ECRS has a value "well above" the level recommended by the Monitor. He said the Protocol Revision Subcommittee's (PRS) $1,000/MWh proposal falls "somewhere reasonably" in the middle.

ERCOT's Jeff Billo, director of operations planning, said the grid operator agrees with the concept of a floor and that it needs to be done correctly "regardless of the quantity."

"Then we can continue to work on what is the right methodology for determining the quantity," he said. "We're coming at this with different viewpoints on the offer floor."

TAC's first attempt to endorse NPRR1224, as amended by the Monitor's comments, fell flat at 10-18 with two abstentions. Its only support came from the consumer and retail segments.

A second motion to endorse the change with the offer floor set at $500/MWh met the same fate by an identical vote. The retail segment was joined by the municipal segment.

A third attempt at passage, this time as originally proposed by the PRS, also failed, at 15-11, with four abstentions. It was opposed by the consumer and retail segments.

Finally, on its fourth attempt, TAC endorsed the measure. It must still be approved by the board and Texas Public Utility Commission, but

ERCOT News

it has been assigned urgent status so it can be effective this summer.

TAC Endorses $1.2B Project

TAC endorsed the ERCOT Regional Planning Group's recommended $1.2 billion project to rebuild 345-kV infrastructure in West Texas that will address thermal overloads and petroleum production load-growth issues in the region.

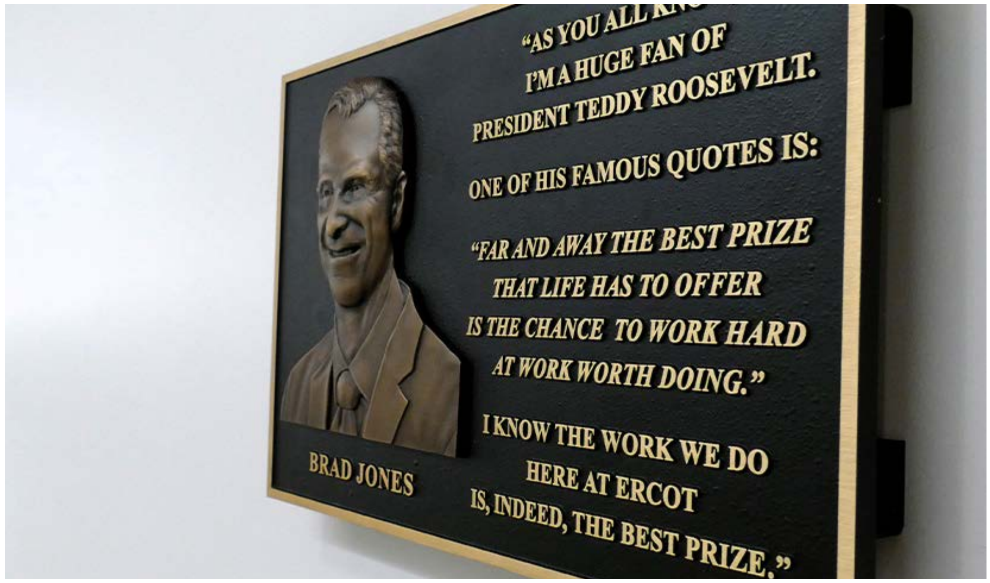
The project easily cleared the $100 million threshold to be classified as a Tier 1 project, necessitating board approval.

Assuming the rebuild is approved, Oncor, the transmission provider, will disconnect existing 345- and 138-kV transmission lines before rebuilding about 245 miles of new transmission lines and switches. It will also build a new substation and upgrade terminal equipment.

The project was first identified in the grid operator's *2021 Permian Basin Load Interconnection Study*. Staff conducted a subsynchronous resonance (SSR) screening for the rebuild. They found no adverse SSR effects to the existing and planned generation resources and also determined the project did not cause new congestion within the area.

The utility plans to complete the work by summer 2028.

Plaque Honors Brad Jones



ERCOT has installed a plaque memorializing Brad Jones at its Austin headquarters. | *© RTO Insider LLC*

ERCOT has installed a plaque across from the board room memorializing former interim CEO Brad Jones, who died last year.

Jones took over the grid operator's reins in the wake of the disastrous and deadly February 2021 winter storm. He worked to raise public confidence in ERCOT and steady the ship before handing the helm to current CEO Pablo Vegas. (See *Brad Jones, Former ERCOT, NYISO CEO, Dies at 60*.)

The plaque includes a quote from Teddy Roosevelt, Jones' favorite president. It reads: "'Far and away the best prize that life has to offer is the chance to work hard at work worth doing.' I know the work we do here at ERCOT is, indeed, the best prize."

Staff have also planted a tree in his memory outside ERCOT's operations center in nearby Taylor.

Theme of the Month

The meeting got off to a rocky start when ENGIE's Helton attempted to submit a friendly amendment to the phrase of the month brought forward by American Electric Power's Richard Ross.

Ross, who provides a monthly theme for both ERCOT and SPP stakeholder meetings, called in to say May's was "words matter."

"It's been used quite well this week at SPP meetings," Ross said. "I'm quite confident you guys can pull it off."

He resisted Helton's suggestion to add "innovation" as a nod to the ERCOT Innovation Summit the day before.

"I hate to be difficult, but it's my phrase of the month," Ross said as members erupted in laughter.

2 Combo Ballots Pass

TAC members approved a separate combined ballot containing *NPRR1198* and related changes to the Planning Guide (*PGRR113*) and Nodal Operating Guide (*NOGRR258*) that adds an extended action plan as a constraint-management plan suitable to managing congestion resolvable by SCED.

Calpine, CenterPoint Energy, Jupiter Power and South Texas Electric Cooperative abstained from the unanimous vote, with Calpine's Bryan Sams saying his company prefers SCED solutions.

EDF Renewables' Alexandra Miller, the NPRR's sponsor, said her group included all input and requests to ensure transparency was consistent throughout the changes.

"This is not something that is done outside of SCED, and it is a change to the system configuration. ... Scalability is allowing transmission owners to operate and choose what to respond with," she said.

TAC unanimously endorsed its combo ballot and the withdrawal of a Planning Guide revision request (*PGRR105*) that would have added DC ties to the list of resources that must meet minimum deliverability conditions. ERCOT staff said the PGRR was contrary to a recent PUC decision and that it raises a policy issue that is best suited for the commission.

The ballot also included the Real-time Co-optimization Battery Task Force's recommended *mitigated offer cap* for all hydro resources and five NPRRs that, if approved by the ERCOT board, would:

- *NPRR1218*: update the state's renewable energy credit trading program to clarify that it only applies to solar renewable energy.
- *NPRR1220*: modify the market's restart process to require board and TAC approval and provide an alternative mechanism to board approval under certain circumstances.
- *NPRR1222*: elevate final approval of the "*ERCOT Methodologies for Determining Minimum Ancillary Service Requirements*" other binding document from the board to the PUC, consistent with commission discussions.
- *NPRR1223*: update a protocol form to require transmission and/or distribution service providers to provide contact information to ERCOT.
- *NPRR1228*: decrease the number of firm fuel supply service obligation periods awarded in a procurement from two to one. ■

— Tom Kleckner

ISO-NE News

FERC Directs ISO-NE to Submit Another Order 2222 Compliance Filing

By Jon Lamson

Responding to a rehearing request by Advanced Energy United over FERC's partial acceptance of ISO-NE's third Order 2222 compliance filing, FERC has directed ISO-NE to submit an additional filing to specify its metering and telemetry practices for distributed energy resource aggregations (DERAs) (*ER22-983-006*).

Order 2222, which requires RTOs to update their tariffs to enable DERAs to participate in wholesale markets, has led to a long series of compliance filings and rehearing requests related to ISO-NE's compliance.

FERC accepted ISO-NE's fifth compliance filing April 11, subject to further compliance. (See *Still More Work for ISO-NE on Order 2222 Compliance*.)

On May 23, FERC issued an order on rehearing responding to Advanced Energy United's challenge of ISO-NE's third compliance filing, which FERC accepted Nov. 2, 2023. (See *FERC Accepts ISO-NE Order 2222 Compliance Filing*.)

"We sustain three of the four findings AEU [Advanced Energy United] challenges," FERC ruled.

Responding to the trade association's argument that ISO-NE's three metering options for DERAs — "retail delivery point metering, submetering with reconstitution and parallel metering" — are unnecessarily prohibitive, FERC affirmed its finding that these options "do not pose an unnecessary or undue barrier to individual DERs joining an aggregation."

FERC upheld its acceptance of ISO-NE's proposal to apply the requirements of the "binary storage facility" and "continuous storage facility" participation models for DERAs to provide withdrawal service. FERC also continued to find that the ISO-NE properly explained the steps it took to "avoid imposing unnecessarily burdensome costs on DER aggregators and individual resources in DERAs."

However, FERC set aside its prior ruling that ISO-NE adequately described its metering requirements for DERAs.

"Specifically, we set aside our finding that, for those DERAs containing behind-the-meter DERs, ISO-NE's tariff includes a basic description of the metering practices for DERAs with references to specific documents that contain further technical details for metering and telemetry practices," FERC wrote.

"ISO-NE's basic description of its metering practices for DERAs is incomplete because its tariff does not include submetering requirements for DERAs participating as submetered Alternative Technology Regulation Resources," FERC added.

FERC directed ISO-NE to submit an additional compliance filing to specify these submetering requirements. FERC also set aside its ruling that ISO-NE's proposal to extend "existing requirements for Alternative Technology Regulation Resources to DERAs" is just and reasonable, writing that it will reassess these requirements after the RTO submits its additional compliance filing.

| *Shutterstock*

Caitlin Marquis of Advanced Energy United said FERC's directive "sends ISO back to the table to resolve one metering barrier for DERs seeking to provide regulation service, which is welcome and important."

"However, as New England and the rest of the country face rising demand, rising electricity prices and reliability threats, much work remains to ensure the region is taking full advantage of DERs," Marquis added.

Commissioner Mark Christie concurred with the parts of the order that accepted ISO-NE's filing and dissented "to the rest."

Christie decried Order 2222's "seemingly never-ending and avoidable rounds of compliance filings" and called the compliance saga a waste of time and money. ■

ISO-NE News

FERC Responds to Mystic Agreement Rehearing Request

By Jon Lamson

FERC has denied a rehearing request and partly adopted a clarification request by Constellation Energy related to a challenge to the fixed costs associated with the Mystic cost-of-service agreement (COSA) (*ER18-1639-028*).

Initially signed in 2018, Mystic's COSA between Constellation and ISO-NE delayed the retirement of the Mystic Generating Station by two years to help provide fuel security to the region. The agreement is set to expire — and Mystic to retire — at the end of May.

As part of the COSA, Constellation is required to submit annual informational filings related to the costs of the agreement. Relevant stakeholders are allowed to request more information and ultimately challenge the filings with FERC.

The May 23 FERC ruling stems from an October 2022 series of challenges by a group of municipal utilities to an informational filing submitted that year.

In December 2023, FERC granted several of the municipal utilities' challenges, determining "that the challenges raised issues of material fact that could not be resolved on the record before the commission, and thus established hearing and settlement judge procedures."

In January 2024, Constellation requested rehearing on three of the order's rulings and clarification on two rulings — while also requesting rehearing on the latter two rulings if not granted the clarifications.

"The relief sought herein is aimed at avoiding unnecessary litigation in a case that has seen too much already," the company *wrote*.

In its ruling May 23, FERC dismissed the rehearing requests on the basis that the challenge order was not a final decision and therefore not subject to rehearing.

FERC did grant Constellation's clarification request regarding projected 2023 capital expenditures at the Everett LNG import facility, which also is owned by Constellation and provides the fuel for Mystic via a *fuel supply agreement*.

A 2022 *settlement agreement* among Constellation, the New England states and ISO-NE "resulted in the Mystic Agreement no longer providing recovery for any Everett 2023 [reliability-must-run capital expenditures]," FERC wrote.

"Accordingly, we grant Mystic's requested clarification and determine that there is nothing further to litigate" regarding this aspect of the informational filing, FERC ruled.

Meanwhile, FERC affirmed its 2023 ruling to "set for hearing and settlement judge procedures" the three other formal challenges to the informational filings, which relate to the calculations of Mystic and Everett's rate bases prior to the agreement. ■

The Mystic Generating Station in Everett, Mass. | *Shutterstock*

ISO-NE News

Massachusetts DPU Approves Everett LNG Contracts

By Jon Lamson

The Massachusetts Department of Public Utilities has approved agreements between Constellation Energy and the state's investor-owned gas utilities to keep the Everett LNG import facility operating through May 2030.

The Everett Marine Terminal (EMT) is the only facility in the state that can import and directly inject LNG into the gas network, but it has faced an uncertain future, with Constellation's cost-of-service agreement with ISO-NE expiring at the end of this month. Constellation owns both Everett and the Mystic Generating Station, Everett's anchor customer, which is set to retire at the same time.

Following extended negotiations with the state's gas utilities dating back to 2021, National Grid, Eversource Energy and Unitil filed agreements with Constellation in February to help cover the facility's fixed costs and provide the utilities the option to purchase LNG as needed.

The utilities argued that the agreements were necessary for the reliability of the gas network, but they were met with pushback by environmental organizations and state agencies about the cost and climate implications of the agreements. The Conservation Law Foundation (CLF) opposed the agreements, while groups including Enbridge, Tennessee Gas Pipeline and Constellation supported the utilities' filings.

Neither the Massachusetts Attorney General's Office nor the state Department of Energy Resources took an explicit stance on the contracts, but both called for additional transparency and reporting requirements. (See *Mass. AGO, DOER Call for Climate Guardrails on Everett LNG Contracts*.)

In its ruling, the DPU found that "without the agreements, each company will not have sufficient natural gas supplies to reliably serve its customers in design-winter scenarios during the term of the agreements, which could jeopardize the health and safety of its customers during the cold winter months."

Responding to CLF's argument that utilities did not adequately consider alternatives, the DPU ruled that "the alternatives to the agreements currently available to each company, including electrification, are insufficient to fully replace supplies from EMT or provide the reliability benefits that EMT offers."

The DPU also disagreed with CLF's contention that the agreements are not compatible with the state's climate laws. The department noted that Eversource's and Unitil's contracts are intended to replace existing gas supply contracts and are therefore in line with the precedent set by previous rulings.

Meanwhile, National Grid indicated that its contract is needed in part to help meet increasing gas demand from oil-to-gas heating conversions. The department found that this justification is aligned with previous rulings "that the acquisition of incremental natural gas supply to serve new customers that convert from oil heating to natural gas heating is consistent with the" *Global Warming Solutions Act*.

Aerial view of the Mystic Generating Station in Everett, Mass. | *InvictaHOG, Public Domain, via Wikimedia Commons*

However, the DPU wrote that it may need to revisit this precedent following its December 2023 order (20-80-B) creating "a new regulatory framework" to discourage new investments in gas infrastructure. (See *Massachusetts Moves to Limit New Gas Infrastructure*.) The department also said it intends to consider whether equity and affordability impacts should be included in the evaluation of similar contracts going forward.

Instead of changing the standard of review within the Everett proceedings, "the department finds it appropriate to engage in a more thoughtful, comprehensive process involving the participation of all interested stakeholders," the DPU wrote.

The department agreed to include annual transparency and reporting requirements around the cost and climate effects of the agreements, as well as on the utilities' efforts to reduce their need for Everett.

"We agree with the attorney general and DOER that open and transparent insight into the companies' efforts to reduce or eliminate their reliance on EMT is critical to ensuring that the commonwealth remains on a path to achieve its decarbonization goals," the DPU wrote.

Throughout the process, climate and environmental advocates in the state have expressed concern that the contracts could function as a stop-gap measure to a more permanent pipeline capacity expansion into the Northeast. Enbridge has said it could complete a major capacity expansion of the Algonquin pipeline by the end of the decade. (See *Enbridge Announces Project to Increase Northeast Pipeline Capacity*.)

Joe LaRusso, senior advocate at the Acadia Center, said the DPU's approval of the contracts is "potentially in conflict with Order 20-80," particularly if the contract timelines are intended to align with Enbridge's pipeline expansion effort.

He said the reporting requirements should give the DPU ample information on the utilities' gas demand trajectories, with the "open question" being whether the DPU allows the companies to reduce their reliance on Everett by securing additional pipeline capacity.

Meanwhile, Constellation applauded the DPU's ruling, writing in a statement that the contracts will help "ensure adequate gas availability during extreme weather conditions as the region transitions to clean energy." ■

ISO-NE News

FERC Approves Additional Delay of ISO-NE FCA 19

By Jon Lamson

FERC has approved an additional two-year delay of ISO-NE's forward capacity auction (FCA) 19, pushing the auction to February 2028 (*ER24-1710*). The auction applies to the 2028/29 capacity commitment period (CCP), which begins in June 2028.

The delay will give ISO-NE time to develop major changes to the timing and structure of its capacity auction. The RTO has proposed changing its "forward annual" auction to a "prompt seasonal" auction. This would reduce the time between the auction and the CCP from a span of over three years to just a few months, while the annual CCP would be split into distinct seasons. (See *ISO-NE Moving Forward with Prompt, Seasonal Capacity Market Design*.)

ISO-NE also plans to use the delay to continue working on its resource capacity accreditation (RCA) project, which is intended to better align capacity awards with system reliability benefits. (See *ISO-NE: RCA Changes to Increase Capacity Market Revenues by 11%*.)

"The further delay of FCA 19 provides the opportunity for substantial market efficiency improvements and reliability benefits associated with a prompt seasonal market," ISO-NE wrote in its initial filing.

| © RTO Insider LLC

The RTO added that implementing a prompt seasonal market at the same time as the RCA reforms would create "multiple synergies," including the ability to take extra time to develop an optimal approach to accrediting gas resources, which has been a sticking point in the RCA stakeholder discussions. (See *NEPOOL MC Backs Further Forward Capacity Auction Delay*.)

Following FERC's May 20 approval of the delay, ISO-NE has indicated it will pause RCA discussions and will "target discussing initial scope considerations with the [Markets Committee] in July, Dane Schiro of ISO-NE said at this month's Markets Committee meeting.

Regarding resource modeling and projected capacity market revenues for different resource types, "a lot of the underlying assumptions will remain the same," said ISO-NE spokesperson Matt Kakley. He added that some resources with varying seasonal benefits could see seasonal swings in their accreditation values, while some resources will experience minimal changes.

The ruling will delay the auction until 2028 but does not commit the region to implementing a prompt seasonal market. FERC previously approved a one-year delay as ISO-NE and stakeholders contemplated pursuing the market changes. (See *FERC Approves ISO-NE's One-Year Delay of FCA 19*.)

Like the previous delay filing, if ISO-NE ultimately can't pass a prompt and seasonal auction design, future auctions will proceed in 10-month increments, gradually increasing the time between the auction and the CCP until the auction returns to its current three-year-forward timeline.

The filing was supported in comments by ISO-NE's internal and external market monitors and the New England States Committee on Electricity and was not opposed by any groups.

"The proposed delay will allow ISO-NE and stakeholders the time necessary to develop a prompt and seasonal capacity market framework and refine capacity accreditation methods," FERC ruled. ■

ISO-NE News

Overheard at the 76th Annual NECPUC Symposium

From left: Georgia PSC Commissioner Tricia Pridemore; NPCC CEO Charles Dickerson; Emily Green, Conservation Law Foundation; Rita King, Avangrid; and Massachusetts DPU Commissioner Staci Rubin. | *© RTO Insider LLC*

CARROLL, N.H. — Angst over looming load growth, cost increases and reliability headaches headlined the 76th annual New England Conference of Public Utilities Commissioners (NECPUC) Symposium, held May 20-21 at the Mount Washington Hotel.

"I think it is a laudable goal to want to get rid of any greenhouse gas-emitting source, but we're going to have to do this at pace," said Charles Dickerson, CEO of the Northeast Power Coordinating Council. He said that as policymakers push for "100% reliable, 100% renewable and 100% really cheap [power], I just don't think those three [aspects] can exist in one space at one time."

Dickerson called on regulators to work to encourage innovation and be "a little less rigid" around cost recovery for utilities experimenting with new solutions.

"If we take the same approach to regulation that we've taken over the past 100 years, it's probably going to take us 100 years to solve this," Dickerson said, adding that regulators should try to approach the looming challenges with "a little bit more risk tolerance and a lot more creativity."

Vineyard Offshore CEO Alicia Barton pushed back with a more optimistic tone.

"Respectfully, I do disagree — actually pretty strongly — that we can't do all three," said Barton, former CEO of the New York State Energy Research and Development Authority. She emphasized that changes to the power purchase agreement model, including tweaks to contract lengths and inflation-adjustment mechanisms, could help bring costs down.

"You can actually get better costs if you leverage some of these choices," Barton said.

Richard Levitan of Levitan & Associates recommended that public utility commissions "embrace principles of transparency, honesty and realism" when weighing competing priorities.

"I don't think in the pursuit of clean, reliable and affordable [that] there are easy tradeoffs," Levitan said. "There is no one unassailable answer; there's no quick solution; but constructive debate with prominent stakeholders — possibly through the ISO, but at the state level too — should inspire awareness, and I think that's a laudable goal."

Coping with Increasing Demand

ISO-NE *projects* that load growth will rapidly accelerate in the coming decades, doubling current peak load levels by 2050. The RTO estimates that the transmission upgrades required to meet this peak will cost in the range of $19 billion to $26 billion. (See *ISO-NE Analysis Shows Benefits of Shifting OSW Interconnection Points*.)

These upgrades will come on top of increasing costs associated with upgrading and climate-proofing distribution networks and

ISO-NE News

accumulating state PPAs. (See *How Sea Level Rise, Coastal Flooding Threaten Boston's Grid*.)

One way to limit costs would be to maximize the potential of high-performance conductors and grid-enhancing technologies (GETs) like dynamic line ratings, advanced-power flow control and topology optimization, said Rob Gramlich, president of Grid Strategies.

Gramlich noted that the deployment of GETs in the U.S. has lagged behind other countries.

"You just have to wonder whether the cost-of-service regulatory model — which rewards large capital investments — is a disincentive for getting senior management at utilities to really deploy these things," Gramlich said. "I think we're at the place nationally with GETs where there's a need for some independent expert who has access to all the information to identify where the right technology could apply."

Tiffany Menhorn, principal at the Menhorn Group, said GETs often can provide ancillary grid resilience benefits and give utilities "eyes on your line like never ... before."

Along with better real-time awareness, predictive analytics could provide significant insights into asset health and help to identify anomalies, Menhorn added.

Speakers also highlighted retail demand response as an area for improvement that could significantly reduce the overall costs associated with the clean energy transition.

ISO-NE CEO Gordon van Welie said activating DR at the retail level remains "a work in progress."

In February, NECPUC launched a yearlong *working group* to look at how retail DR can help address peak load and resource adequacy challenges.

"What I hope for is a standardized approach to doing demand response in the region," van Welie said, adding that deploying automation, sending the right price signals and incorporating retail DR into the wholesale markets will be essential. As winter risks increase, longer-duration DR that can extend over multiday periods will become increasingly valuable. "That's a much more complicated type of demand response, and I think it's an opportunity for us to innovate as a region."

The Role of Natural Gas

Several of the speakers presented significantly different visions for the role natural gas and gas pipelines will play in the coming decades.

"I hope that states don't get away from … everything that we're doing to ensure the safety and reliability of that infrastructure," said Georgia Public Service Commissioner Tricia Pridemore, who is also first vice president of the National Association of Regulatory Utility Commissioners.

From left: Tiffany Menhorn, Menhorn Group; Rob Gramlich, Grid Strategies; Vermont Electric Cooperative CEO Rebecca Towne; and Maine PUC Commissioner Carolyn Gilbert. | *© RTO Insider LLC*

"I'm a pro-gas commissioner," Pridemore said. She noted a *report* by the National Petroleum Council that found that "the pipeline infrastructure is going to be with us for a long time," arguing that alternative fuels like hydrogen and renewable natural gas (RNG) will rely on the gas system as states decarbonize.

Marc Brown of the Consumer Energy Alliance, an advocacy group whose members include a wide range of industrial end users and fossil fuel companies, called natural gas "part of the solution" and argued that the most significant decarbonization gains over the past two decades have come from the proliferation of natural gas.

He said environmental progress and decarbonization "is going to take people accepting the fact that natural gas is going to continue to play an important role in affordability, reliability and emissions reductions in the near- and midterm future."

In contrast, Emily Green, senior attorney at the Conservation Law Foundation, said states should engage in long-term planning efforts to transition off fossil fuels, including natural gas. She highlighted the significant warming effects of methane leaks from the gas system, which are typically *underestimated* by state and national greenhouse gas inventories.

"We're going to be paying for today's investments in gas for decades to come, both in terms of emissions and ratepayer impacts," Green said. "It's low-income consumers that are going to be left holding the bag."

Green also called on regulators "to be very wary of utilities looking to maintain or even upgrade pipelines on the future promise of biomethane or hydrogen."

In the Massachusetts Department of Public Utilities' final rule on its multiyear "Future of Gas" investigation, it found that efforts to blend hydrogen and RNG into the gas network should not be funded through the general rate base (*20-80-B*).

"The department is uncertain about the viability of hybrid heating and hydrogen technologies and their potential as economical long-term solutions for ratepayers," the DPU wrote, adding that "RNG and the use of hydrogen as a fuel are emerging technologies that have not yet been proven to lead to a net reduction in GHG emissions." ■

— Jon Lamson

MISO: Worsening Uninstructed Deviation Needs Attention

By Amanda Durish Cook

Five years after it introduced rules to curb generators' uninstructed deviations from dispatch instructions, MISO said such departures are worse than ever and it likely needs to strengthen rules and software.

"Despite an initial increase in dispatch-following performance since the 2019 uninstructed deviation changes, the fleet is now performing below" pre-rule levels, MISO Market Settlements Adviser Mollie Dawson said at a May 23 Market Subcommittee meeting. She said the high number of departures from dispatch instructions remains attributable to renewable energy sources.

MISO said it will mount a "multifaceted approach" that may include new market rules and operational tools. The RTO said it will draft the changes in collaboration with its Independent Market Monitor and stakeholders.

"Our current rules are not meeting the challenge of the impact," Dawson said.

Dawson said new potential fixes might include MISO introducing settlement penalties, stepped-up requirements to follow MISO-generated setpoints, capping use of manual dispatch and improving its forecast output of intermittent resources.

Dawson said MISO will consult with its Independent Market Monitor in July and bring a slate of potential solutions to stakeholders for evaluation in August.

MISO four years ago placed harsher tolerance limits on generation operators' deviations from its dispatch orders. The rules determine a generator's deviations by comparing the time-weighted average of a real-time ramp rate with a day-ahead offered ramp rate, while allowing for 12% tolerance from setpoint instructions. The rules at the time eliminated the RTO's "all-or-nothing" eligibility for make-whole payments, instead allowing generators to collect full payments when they respond to dispatch instructions at 80% or higher over an hour, while excluding payouts when performance rates fall below 20%. Units operating between those two thresholds earn make-whole payments in proportion to performance.

Before then, generators in MISO were flagged when they deviated by more than 8% from dispatch signals over four consecutive intervals. (See *MISO Plans for New Uninstructed Deviation Rules*.)

MISO IMM David Patton last year recommended MISO improve its near-term wind forecasting to better reflect the characteristics of wind generation output. He said MISO currently uses a "persistence" forecast that assumes wind resources will produce the same amount of output as it most recently observed. MISO stakeholders have said that forecasting style is problematic when wind dies down suddenly. (See *MISO Shelves IMM's Transmission Planning Recommendation in State of the Market Report*.)

After MISO implemented its uninstructed rules in mid-2019, Patton said more wind operators migrated to using MISO's wind forecasts instead of their own, less accurate forecasts. ■

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MISO Says Risk Driving It to LMR Reorganization, Stronger Requirements

By Amanda Durish Cook

CARMEL, Ind. — MISO said with resource adequacy risks at its doorstep, it may need to place tougher requirements on its load-modifying resources and devise new, nonemergency means of using the load offsets that cannot meet new performance standards.

During a May 22 Resource Adequacy Subcommittee, MISO's Neil Shah said he expects the grid operator will use LMRs differently from how they've been used in the past to aid reliable grid operations. He said MISO plans to "redefine the LMR product" and "remap" its load management that can't meet qualifications into potentially new resource modes that can be used during nonemergency conditions. The LMR category going forward might contain only those resources that can be ready within 30 minutes, MISO staff suggested.

Shah said MISO still plans to draw on "all types of resources both on the demand side and the supply side." He said reserves that cannot meet new LMR standards will still be used to aid reliability in the MISO markets, albeit differently.

"We see the grid is transforming at a rapid pace. We see the risk patten changing," Shah said, adding that the LMR construct must change with it.

Shah said that since 2007, LMRs have been used strictly during emergency conditions. LMRs are out-of-market voluntary response resources, Shah said, which are "guaranteed capacity market payment regardless of actual performance." He said when MISO begins issuing capacity advisories and emergency alerts, LMRs sometimes will self-schedule reductions, and because MISO isn't aware of the load offsets until after they occur, it complicates MISO's ability to estimate needs before peak hours.

Shah said MISO plans to present its new approach to LMRs at its Resource Adequacy Subcommittee's July meeting.

Sustainable FERC Project's Natalie McIntire asked that MISO find ways to "maximize" the resources that might not be able to make the LMR cut.

Michigan Public Power Agency's Tom Weeks said it might be simpler for MISO to remove the requirement that it be in an emergency before LMRs can be accessed. He also said he wished MISO would "weed out bad actor" LMRs that don't provide load reductions as promised.

"Instead of using a scalpel to correct the issue, MISO is pulling out a bone saw and doing Civil War-like medicine to cut off a limb," Weeks said.

Neil Shah, MISO | *© RTO Insider LLC*

Shah acknowledged MISO needs better-defined auditing and monitoring standards for its LMRs. He repeated that MISO is open to creating a new market product to make sure participants can make use of longer-lead demand response offerings. However, MISO's Zak Joundi later said MISO prefers to route nonemergency LMRs into one of its existing participation categories.

Shah said MISO can examine its current Demand Response Resource Type I participation model to make sure it's still useful to participants. If not, MISO can make tweaks, he said.

"It's MISO's job to make sure that it can make use of the resources available to it," WPPI Energy's Steve Leovy said. He argued that MISO shouldn't need strictly 30-minute LMRs and that it should activate emergencies a few hours beforehand when it requires demand response. MISO should expect some level of inefficiencies during emergencies, he said.

"We're talking a few times a year during severe conditions … to keep the system intact," Leovy said.

"Managing a 15-state footprint is incredibly complicated. When you get into real-time emergency conditions, more simplicity is needed in the design," Executive Director of Market Operations JT Smith said.

Smith said the problem of when LMRs could deliver wasn't present 10 years ago because MISO had ample resources. Now, he said MISO's "entire reserve fleet is sitting behind an emergency call."

MISO initially was slated to use summer to design a new capacity accreditation for its LMRs; however, it said it was persuaded by stakeholders to pause on remodeling accreditation in favor of redrafting the LMR rulebook.

LMRs were not included in MISO's recent filing to implement a new capacity accreditation that would accredit resources based on their projected availability and historical performance during periods of high system risk. (See *Stakeholders Deliver Negative Reactions to Proposed MISO Capacity Accreditation at FERC*.)

Before it announced the pivot, MISO said it considered splitting LMRs into emergency and nonemergency resources, giving 100% capacity credit to more nimble, emergency LMRs and apply a sliding scale to nonemergency LMRs that would reduce capacity credits as response times rise. ■

MISO News

MISO Braces for Hot Summer, Potential 130-GW Peak

By Amanda Durish Cook

MISO said it's expecting a hot summer footprintwide and while it should be able to survive load peaks into the 120-GW level, the system could be at the brink if a scorching day produces demand near 130 GW.

Per usual, MISO said the bulk of the danger lies in July. MISO said it likely will encounter a 122.6-GW peak sometime that month but doesn't rule out a high-demand forecast of 129.3 GW. That level of demand would break all load records, outstrip its 123.8 GW of cleared, accredited capacity and force it to declare an emergency to access its approximately 15-GW store of operating reserves and load-modifying resources.

In June, MISO said load could crest at an expected 115 GW or climb near 122 GW in a high-demand scenario. By August, MISO expects an almost-120-GW peak load under normal conditions, or as much as 126 GW.

MISO's all-time summer peak of 127 GW occurred July 20, 2011. Last year, MISO expected to eclipse that record twice during late August and early September heat waves that produced temperatures exceeding 95 degrees in northern portions of the footprint. MISO rounded out summer with a 125-GW peak Aug. 23. (See *MISO: Could Have Employed Wait-and-see Approach for August Emergency*.)

During a May 21 summer readiness workshop with stakeholders, MISO resource adequacy engineer John DiBasilio said while MISO should have sufficient capacity under normal operating conditions, it's likely to enact emergency procedures if demand intensifies this summer.

The RTO estimates it has a 4.6-GW capacity surplus beyond its 136-GW planning reserve margin requirement heading into summer from excess capacity offered into the auction and from members' fixed resource adequacy plans.

MISO's primary weather forecast vendor, data analytics and technology company, DTN, has predicted "above-normal to well-above-normal" average temperatures May through September.

The RTO noted that the National Oceanic and Atmospheric Administration is projecting above-normal temperatures across the country June through August. MISO also said it expects precipitation this summer between near normal and slightly above normal.

MISO in-house meteorologists Brett Edwards and Adam Simkowski said it doesn't seem that the RTO can use last summer, which held nearly normal average temperatures in MISO Midwest, as a reference for the upcoming summer. They said more appropriate reference points include summers where load topped 120 GW systemwide and more than 30 GW in MISO South.

Edwards said all data points to a very warm summer, and MISO expects "pervasive heat across pretty much the entire continental U.S."

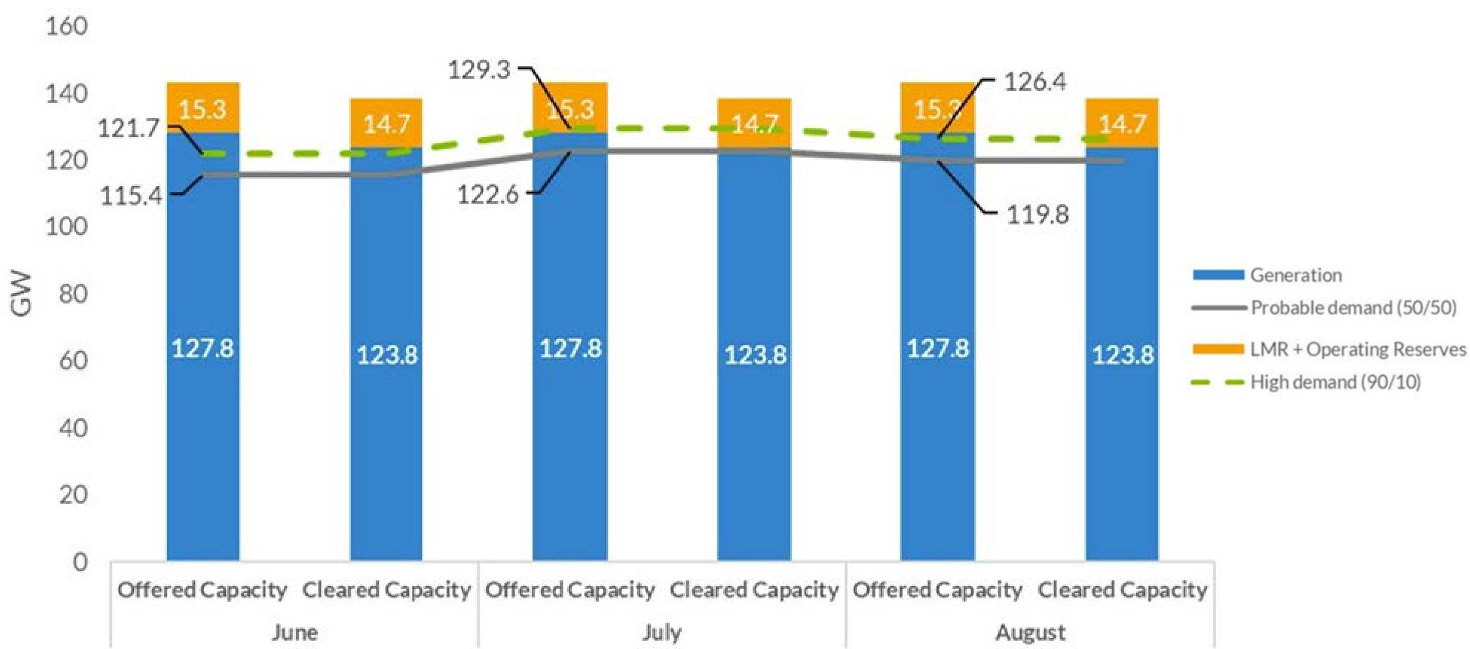
The RTO anticipates a developing La Niña weather pattern contributing to hotter conditions in July and August.

MISO also said there's a good chance heat could emanate from the eastern U.S. this summer, affecting PJM's ability to export to MISO during heat waves.

"That's something we're going to be watching closely as the entire Eastern Interconnect heats up," Simkowski said.

"Our teams are constantly working to identify and manage the areas of growing risk within our region and throughout our industry," Executive Director of Market Operations JT Smith said in a press release.

Finally, MISO said while it's expecting solar penetration to increase to 6 GW of in-service capacity this summer, it's also keeping an eye on the potential for wildfire smoke drifting from Canada to stifle a percentage of output. MISO has been routinely breaking its own solar records monthly as developers complete solar farms. Currently, MISO's solar arrays are briefly capable of about 5-GW *peaks*. ■



MISO summer peak load and capacity projections | *MISO*

MISO News

FERC OKs Allete Securities Sale Prior to Acquisition

By Amanda Durish Cook

FERC has granted Allete permission to sell several hundred million dollars in securities to raise funds for its clean energy transition.

In a May 23 order, FERC said Allete is clear to issue stock and up to $977 million in short-term debt, up to $275 million in long-term debt and a maximum of $516 million in the sale of tax credits and tax equity financing (*ES23-71*). The commission's authorizations are good for two years.

Allete's ask to FERC predated its acquisition *announcement* this month. The company said it needs money for continued investments in renewable energy, "environmental technology" for its generating units, transmission investments and distribution grid modernization, and other business expenses.

FERC said Allete's request to raise money appeared consistent with the public interest and "reasonably" necessary for Allete's utility services.

Allete said it filed for FERC permission out of an "abundance of caution" because its utility, Minnesota Power, owns and operates wind generation in North Dakota. Last year, the Minnesota Public Utilities Commission authorized Allete to issue long- and short-term debt.

At the time of filing, Allete said it expects its affiliates' capital expenses to overtake its internal cash flow from January 2023 through June 2024.

Allete said with "internally generated cash insufficient to fund the planned capital outlays," it will need to turn to issuances of long- and short-term debt and common stock alongside tax equity financing. Allete also noted in the filing it had been exploring acquisition "and other investment opportunities to diversify [its] revenue base in order to reduce its dependence on revenues from a concentrated industrial base of taconite and paper customers in northeastern Minnesota."

Allete's hunt for a buyer proved successful. Weeks ago, it announced an agreement to be acquired by Canada's pension investment board and private equity firm Global Infrastructure Partners for more than $6 billion. The acquisition and ensuing transition to a private company would help it access even more capital to navigate fleet transition, Allete said. (See *Canada Pension Board, Global Infrastructure Partners to Buy Allete*.)

Allete said it hopes to finalize the deal in 2025. The sale requires approvals from FERC, Minnesota and Wisconsin regulators, the Federal Trade Commission and Allete shareholders. ■

Minnesota Power's Bison Wind Energy Center in North Dakota | *Allete*

NYISO News

National Grid Plans $35B Investment in NY, Mass.

Company Also Expects to Sell U.S. Onshore Renewables Business

By John Cropley

National Grid plans to invest $75 billion in its infrastructure over the next five years, nearly half of it in New York and Massachusetts.

The UK energy company announced the plan May 23 with its *year-end financial results* and said the $35 billion investment in the two states would be over 60% higher than in the past five years.

National Grid also announced it would sell National Grid Renewables, its U.S. onshore renewables business, and Grain LNG, its UK LNG asset, as it focuses more closely on its energy networks.

In a *news release*, National Grid said the New York and Massachusetts projects would harden the electric grid, reduce emissions and provide benefits to both customers and local economies.

The company noted the Department of Energy in its *2023 National Transmission Needs Study* forecast a need for a 255% increase in transmission development to support the two states' anticipated clean energy growth.

The news release emphasized the investments in electric networks and the resulting benefits for states' decarbonization goals. But the financial report indicates a little more than 40% of the $35 billion would be spent on natural gas infrastructure, including a proposed three-year, $5 billion modernization of National Grid's downstate New York gas businesses.

Continued investment in gas infrastructure has been a friction point between utilities and decarbonization advocates. National Grid notes that the work planned would be for safety and reliability purposes and would provide environmental benefits by reducing leaks.

In total, National Grid said it plans to invest about $21 billion in New York through March 2029. More than $4 billion of this would go to the *Upstate Upgrade*, a portfolio of more than 70 transmission enhancements designed to increase reliability, resilience and capacity.

As it announced the upgrade in March 2024, the company called it the largest investment in the grid in its century-plus existence — building, rebuilding or modernizing more than 1,000 miles of transmission line. As a result, 45 substations would be built, rebuilt or modernized.

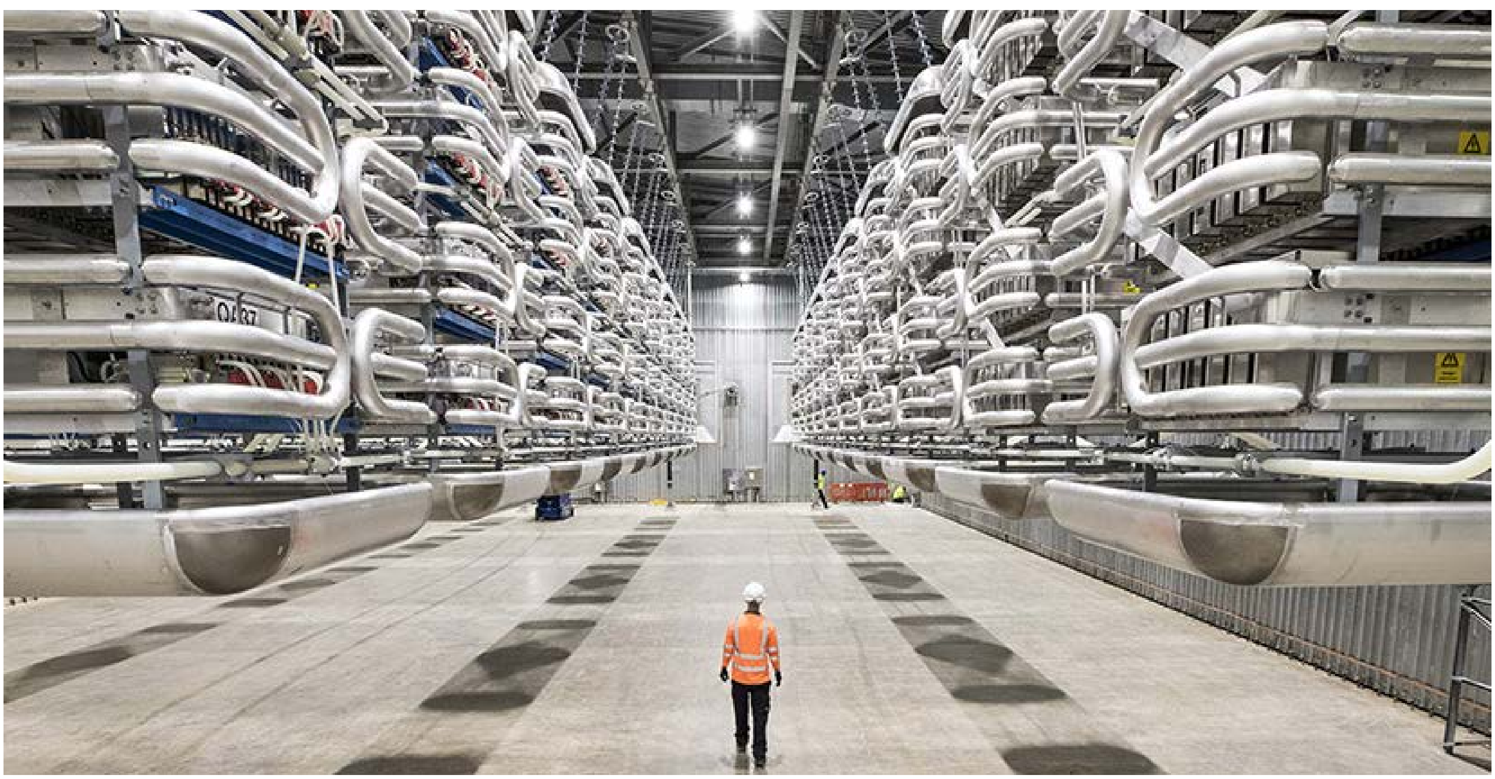
The New England investment would total about $14 billion and include smart meters, modernized infrastructure, hardening against extreme weather and quality upgrades to electric and gas assets. Part of this would be National Grid's *Electric Sector Modernization Plan*, a $2 billion proposal submitted to Massachusetts regulators as part of the state's drive to upgrade the grid and accelerate connection of renewables.

The dollar figures are approximate and are based on present UK-U.S. currency exchange rates.

The plan involves an equity raise of 7 billion British pounds, or nearly $9 billion.

The company's share price, which recently traded near 52-week highs, took a dive after the plan was announced, closing 10.9% lower May 23 on the London Stock Exchange and 14.3% lower on the New York Stock Exchange.

For the fiscal year ended March 31, National Grid's operating profit was down 8% from the previous fiscal year, its pre-tax profit was down 15% and its earnings per share were down 19%. ■

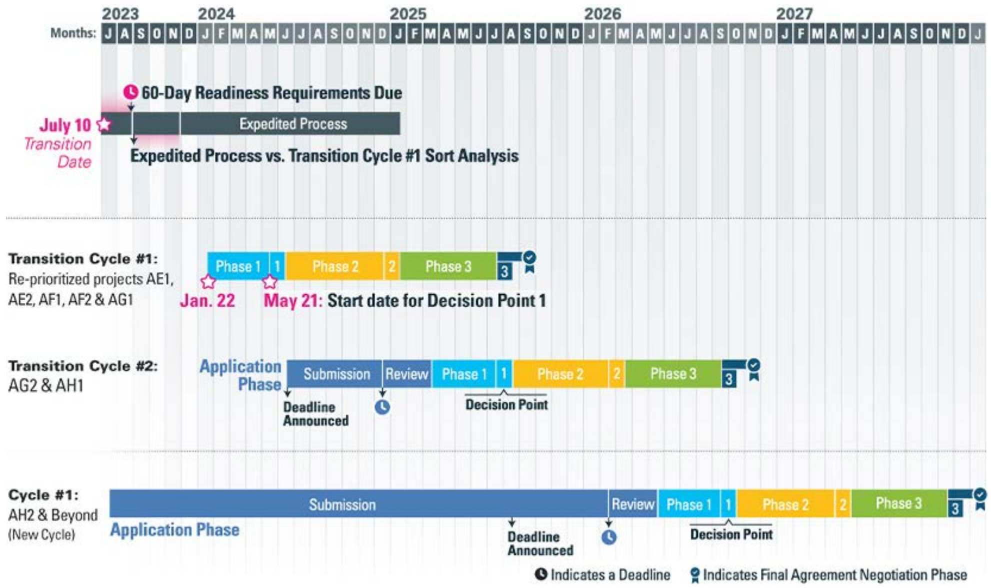


National Grid's IFA2 interconnector, a 1-GW link between the UK and France, is shown in 2020. | *National Grid*

PJM News

PJM Reaches Milestone on Clearing Interconnection Queue Backlog

By Devin Leith-Yessian



A PJM chart outlines its process for studying network upgrades necessary for allowing generators to interconnect. | *PJM*

PJM on May 20 *announced* that it had completed the first phase of studies for 306 generation interconnection requests sorted into the first cycle in the transition to its new interconnection process, a cluster-based study approach intended to reduce how long it takes the RTO to bring generators online.

"This is another critical milestone for PJM's widely supported interconnection process reform," said Aftab Khan, executive vice president of operations, planning and security. "New service requests for generation resources are moving through our process as designed and promised, with more than 200,000 MW of projects to be studied over the next two years to help states advance their energy policy goals."

Developers with projects in Transition Cycle 1 (TC1) will have 30 days to review the system impact studies and decide whether to move forward with their projects to the facility study phase. PJM said those that complete the process will be ready for construction by mid-2025. (See *PJM Initiates Transitional Interconnection Queue*.)

Another 306 projects expected to require minimal network upgrades are being studied through an Expedited Process "fast lane" that is expected to yield final interconnection service agreements (ISAs) throughout this year. PJM also plans to initiate Transition Cycle 2 on June 20, with a likely application deadline by Dec. 16.

PJM said about 72 GW are expected to clear the queue by mid-2025 and 230 GW over the next three years, more than 90% of which is renewable energy or storage.

The cluster-based approach groups projects together on a first-ready, first-served approach to identify any grid upgrades and assign costs. It also includes increasingly large readiness deposits to be made throughout the study process, with the aim of discouraging speculative or uncertain projects from taking focus away from others. PJM said 118 projects have dropped out of the queue or failed to post deposits, out of 734 eligible. (See *FERC Approves PJM Plan to Speed Interconnection Queue*.)

Environmental organizations said the milestone is a welcome first step but that more change is needed.

"PJM worries there's not enough new power coming online, but it's still only approving projects proposed four to six years ago," said Tom Rutigliano, of the Natural Resources Defense Council. "This is a step forward, but PJM's current process is not enough to get these new clean energy projects connected to the grid as quickly as they're needed."

Christine Powell, deputy managing attorney at Earthjustice, said the amount of time it has taken for PJM to get to this stage has already resulted in projects stalling or withdrawing from the queue. "While PJM's shift to a cluster study process is a positive development for the hundreds of clean energy projects waiting to interconnect to the power grid, PJM continues to lag behind other RTOs," she said.

Katie Siegner of RMI pointed to a *study* released in February that found that incorporating grid-enhancing technologies (GETs) into how PJM conducts transmission planning could optimize the use of existing infrastructure to reduce upgrades needed for new projects and speed interconnection studies. The study estimated that about $1 billion in annual production costs could be avoided through 2033 by expanding use of GETs. (See *RMI Report: GETs Could Speed Renewable Development, Save Consumers Billions*.)

PJM's "clearest opportunity for improvement is bringing its interconnection process into compliance with Order 2023, particularly through serious consideration of alternative transmission technologies that could provide faster and cheaper network upgrade alternatives," Siegner said. "The fact that no grid-enhancing technologies have been identified or used as network upgrades to date suggests PJM has more work to do in incorporating these fast, flexible transmission tools into its study methodologies."

PJM spokesperson Jeff Shields told *RTO Insider* the RTO allows and welcomes GETs as components of proposals for its Regional Transmission Expansion Plan and laid out how it will fully comply with Order 2023's requirements around their facilitation in its May 16 compliance filing (*ER24-2045*).

"All of the enumerated [GETs] already are considered and studied as necessary, if merit exists in the use of such technologies, in the course of interconnection studies in the PJM region," Shields said. "This incorporation of new and emerging technology is consistent with the objectives of the final rule, which requires transmission providers to evaluate certain GETs in each and every one of its interconnection studies."

Shields said PJM agrees there is more progress to be made in improving generator interconnection and development, both at the RTO and removing external obstacles. "We are working with stakeholders within the PJM stakeholder process, as well as entities outside of the PJM membership, to accomplish this." ■

PJM MRC Briefs

New Approach to Large Load Addition Capacity Assignments Endorsed

The Markets and Reliability Committee endorsed a proposal to revise how capacity obligations for serving large load additions (LLAs) are calculated to limit capacity assignments to areas where LLAs are forecast to interconnect.

The MRC did not vote on an alternative motion offered by American Municipal Power (AMP) under the committee's truncated voting structure. (See "Changes to Capacity Assignments for Large Load Additions Contemplated," PJM MRC Briefs: April 25, 2024.)

When bringing the issue charge in October 2023, American Electric Power (AEP) and Dominion Energy said the current capacity obligation assignments spreads PJM-approved LLAs across transmission zones, meaning an increased load forecast by an electric distribution company (EDC) participating in the reliability pricing model (RPM) could compel a fixed resource requirement (FRR) entity to procure capacity for load it will not serve.

In February, FERC granted AEP a waiver to alter the capacity obligation calculation for four of its vertically integrated utilities to not include forecast LLAs outside their territories. (See FERC Grants AEP Utilities Waiver of Capacity Obligation.)

The tariff and Reliability Assurance Agreement (RAA) revisions would rework how PJM calculates capacity obligation assignments to exclude LLAs included in Table B-9 of the load forecast from base zonal scaling factors and add those LLAs back when determining the obligation peak load input.

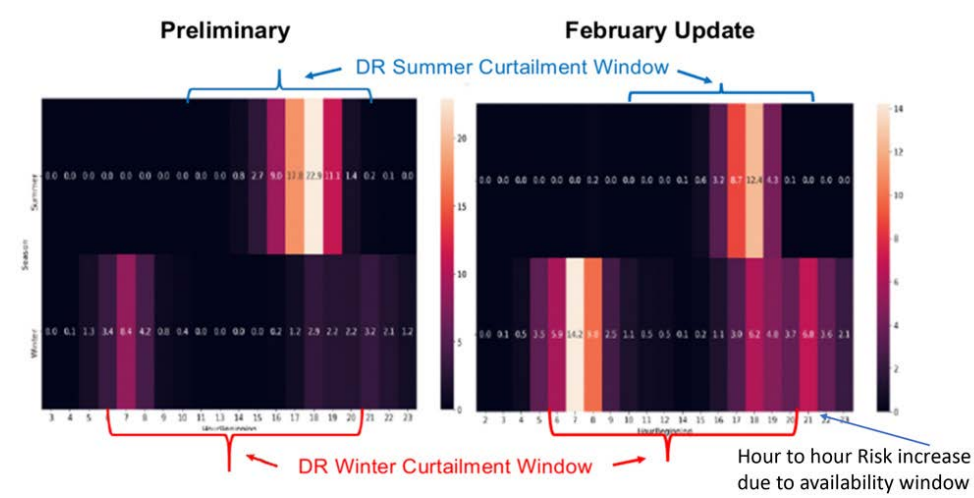
The AMP alternative sought to add a definition of large load additions to the Reliability Assurance Agreement (RAA) to clarify how they can result in capacity obligations for LSEs. The proposed redlines also rewrote a section of the "threshold quantity" definition pertaining to the preliminary forecast peak load for FRR entities in a transmission zone alongside RPM participants to remove the phrase "the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base FRR Scaling Factor." It will instead point to the relevant RAA section.

DR Availability Issue Charge Approved, Quick Fix Proposal Rejected

Stakeholders endorsed an issue charge to investigate modifying the availability of demand response resources, but they rejected a quick fix proposal to expand the winter availability window by two hours. The issue charge passed with 59% sector-weighted support; however, the proposal failed to carry the two-thirds threshold required at 54% support.

The issue charge and quick fix proposal were sponsored by the Advanced Energy Management Alliance (AEMA), PJM Industrial Customer Coalition (ICC), CPower, Enel and NRG Curtailment Solutions. (See "Demand Response Providers Seek Expanded Availability," PJM MRC/MC Briefs: Feb. 22, 2024.)

Bruce Campbell, of Campbell Energy Advisors, said the revised risk modeling approach PJM adopted following the critical issues fast path (CIFP) process conducted last year led to the wintertime hours the model has found hold elevated reliability risks being expanded well into the night. However, the DR availability window was not expanded beyond the status quo 6 a.m. to 9 p.m., preventing dispatchers from using DR to address the full risks the RTO has identified. The proposal would extend the window in which DR is dispatchable by two hours to end at 11 p.m. (See FERC Approves 1st PJM Proposal out of CIFP.)



Several demand response providers argued that PJM's wintertime risk projections, shown on two heat maps, justify expanding the DR availability window. | *PJM*

Campbell argued the longer availability window would not negatively affect the reliability contribution of DR resources, as most participants are industrial load that consumes power at a steady rate throughout the day irrespective of season.

Independent Market Monitor Joseph Bowring said the change would affect the effective load carrying capability (ELCC) rating for DR resources, a calculation tied into the ELCC ratings of all resources. Making a change to one resource would require recalculating all resource class ELCC values, which he said would be difficult and inappropriate to do with the original targeted implementation for the 2025/26 delivery year.

"PJM calculates the contribution of DR resources to reliability for ELCC purposes using an assumed maximum level of response rather than actual data on DR response during the winter. PJM uses actual data for generation resources. The result is that the ELCC of DR is significantly overstated," Bowring told *RTO Insider* in an email. "Actual DR performance/load reduction during Winter Storm Elliott was well below 50% of the stated capacity values. A one-off administrative change to the rules that would arbitrarily increase payments to DR resources and reduce payments to other resources without a comprehensive review of the DR ELCC would be inappropriate."

During the May 22 meeting, Campbell worked with other package sponsors to revise the issue charge to delay the targeted implementation of the quick fix portion of the issue charge to the 2026/27 Base Residual Auction (BRA). The issue charge was also revised to shift implementation of the third key work activity (KWA) — which seeks to eliminate the window outright or create an additional DR classification that would be available all day — to the 2027/28 delivery year. But this alternate version was rendered moot by endorsement of the original package.

PJM News

PJM Director of Stakeholder Affairs David Anders said with the vote on the expanded availability window failing, the KWA is now considered complete and future stakeholder discussions will focus on the other work areas.

PJM Presents Electric Gas Coordination Proposal

PJM presented a first read on a *proposal* seeking to improve alignment between components of the gas procurement timeline and the PJM energy market endorsed by the Electric Gas Coordination Senior Task Force (EGCSTF). (See *PJM Stakeholders Open Poll on Proposal to Align Electric and Gas Markets*.)

The proposal would add three intraday resource commitment runs to the day-ahead market, lining up with the North American Energy Standards Board's (NAESB) gas nomination cycle deadlines. Gas generators would be notified that they are being committed with adequate time for them to nominate for fuel in the subsequent cycle and generators would be asked to voluntarily "use every reasonable effort to notify" PJM if they have procured fuel or expect to do so in time to be scheduled. The manual revisions also say PJM may perform additional resource commitment runs when necessitated by load forecasts, updated resource parameters or changing system conditions.

The proposed revisions to Manual 11 stress that the request for generators to notify PJM if they have or intend to procure fuel is voluntary and does not come with penalties for those who do not provide an update. Gas resources that do not procure fuel necessary to meet their day-ahead or reserve commitments are required to notify dispatchers by adjusting their availability or parameters in Markets Gateway, submitting an eDART ticket and by calling PJM dispatch. The changes include a note stating that keeping dispatchers informed about fuel availability during critical conditions "is essential to providing optimal situational awareness of generator availability to PJM Operations."

Dominion Energy's Jim Davis said the proposal is another step building on real-time values to increase operational certainty around the alignment of the electric and gas markets. The package was sponsored at the EGCSTF by PJM, Dominion and Gabel Associates.

First Read of CIFP Manual Revisions

PJM's Skyler Marzewski presented a set of manual *revisions* implementing capacity market changes drafted through the CIFP process and approved by FERC in January, including several changes to reflect stakeholder feedback received since it was endorsed by the Market Implementation Committee on May 1.

The manual revisions would phase out Manuals 20, 21 and 21A and replace them with new Manuals 20A and 21B, as well as "cleaning up" Manuals 18 and 14B. (See "Stakeholders Endorse Manual Revisions to Implement CIFP Changes to Capacity Market," *PJM MIC Briefs: May 1, 2024*.)

The changes to the Manual 18 language include spelling out a formula that helps determine unforced capacity (UCAP) values for load management resources and clarifying that existing FRR entities may terminate their election to participate in FRR rather than the RPM through "and including" the 2028/29 delivery year without being penalizes.

If endorsed, the capacity market changes would expand the use ELCC analysis for accrediting all generation types, require that planned resources notify PJM of their intent to participate in a Base Residual Auction (BRA) at least 90 days in advance and change how generation UCAP values are calculated. The MRC manual revisions are set to be voted on by the MRC during its June 27 meeting.

The revisions to Manuals 20, 21 and 21A — which focus on the planning side of the CIFP proposal — would establish a new approach to capacity accreditation, reliability risk modeling and BRA procurement targets. The PC is set to vote on the revisions on June 4 and would be included alongside the Manual 18 revisions at the MRC if approved. (See "First Read on CIFP Manual Revisions," *PJM PC/TEAC Briefs: April 30, 2024*.)

Consumer Advocates Intend to Propose Wider DESTF Scope

Maryland and Illinois consumer advocates plan to propose revisions that would widen the scope of the Deactivation Enhancements Senior Task Force (DESTF) to include finding resources that could replace retiring generators and and have PJM consider alternatives to maintaining costly reliability-must-run (RMR) contracts while traditional transmission expansions are constructed to resolve any reliability violations prompted by the deactivation. The current *issue charge* is focused on how RMR compensation is determined, when generation owners need to notify PJM of their intent to deactivate and improving transparency.

Clara Summers, of the Illinois Citizens Utility Board (CUB), said the intent is to supplement

Dave Anders, PJM | *© RTO Insider LLC*

the work of the DESTF, which is discussing proposals from the Monitor and PJM, rather than supplant those efforts.

Phil Sussler, of the Maryland Office of People's Counsel (OPC), said there are multiple stakeholder discussions looking at generation deactivation siloed between the DESTF and other groups, such as the Interconnection Process Subcommittee's work on how capacity interconnection rights (CIRs) may be transferred from a deactivating generator to a replacement resource at the same point of interconnection. Harmonizing those efforts raises the odds of a solution that allows the interconnection process to better react to a deactivation request, he said.

Vistra's Erik Heinle said a balance is needed to ensure discussions do not become so broad that they collapse in on themselves.

"Each of these issues is an important one ... but we also want to make sure we don't get stuck and have the weight of multiple interests preventing us from getting to a solution as expeditiously as possible," he said.

The call for harmonization mirrored comments at the May 8 Public Interest and Environmental Organization User Group (PIEOUG) meeting, where advocates said siloed processes make it difficult for offices with limited resources to track numerous discussions and limits the solutions on the table. (See "Consumer Advocates Call for More Holistic Thinking at PJM," *Consumer Advocates, Environmentalists Urge Holistic Thinking at PJM*.) ■

— Devin Leith-Yessian

SPP News

FERC to SPP: Show More Work on PRM Determination

RTO Added Details to Tariff but Must Make Additional Compliance Filing

By Tom Kleckner

FERC on May 23 found SPP's tariff revisions laying out how it determines its planning reserve margin (PRM) methodology only partly met the commission's order on rehearing and directed an additional compliance filing within 30 days (*ER24-1221*).

The commission said SPP complied with its directive to include a timeline for making changes to the PRM before a planning year in its tariff. But it also said the RTO failed to include further information on how it uses its loss-of-load expectation studies to determine the PRM.

FERC accepted SPP's tariff revisions effective April 10, subject to further compliance.

The commission rejected protests from the grid operator's members that SPP provide three years' notice before increasing the PRM and that it be prohibited from adopting near-term increases without demonstrating that the market has capacity surplus available for purchase. The commission found both arguments to be outside the compliance proceeding's scope, saying its directive only required the timeline for making PRM changes.

The RTO said it will perform an LOLE study at least biennially to determine whether a PRM change is needed and post the results. Staff will then provide a recommendation for any changes, with the Board of Directors and state regulators approving the change. The tariff revisions place additional restrictions on any approved PRM that exceeds the current value or the value identified in the final LOLE results by 1% or more; any PRM increase would be implemented for the planning year, beginning at least one year after approval.

SPP's board in 2022 approved changing the PRM to 15% from 12% over opposition from stakeholders advocating a three-year phase-in. Load-responsible entities unable to meet the requirement can incur financial penalties from the RTO. (See *SPP Board, Regulators Side with Staff over Reserve Margin*.)

FERC last year rejected a complaint by SPP members seeking to overturn the decision. In a 3-1 vote, the commission ruled that American Electric Power, Oklahoma Gas and Electric, and Xcel Energy failed to show SPP's PRM process was unjust, unreasonable or unduly discriminatory because the figure itself was not included in its tariff. (See *FERC Rejects Protest of SPP PRM Increase*.)

AEP, OG&E and Xcel filed a rehearing request with FERC, but the commission took no action on it. They then filed a petition for review with the 8th U.S. Circuit Court of Appeals in July 2023; that proceeding has been held in abeyance pending SPP's compliance filing following a successful FERC motion (23-2734).

FERC found in September 2023 that SPP's proposal failed to "adequately" explain how it would account for the LOLE study's results or any additional considerations when determining the PRM, and that the tariff did not adequately explain the timeline for the RTO's PRM reviews (*EL23-40-001*). FERC ordered a compliance filing within 60 days, but SPP and the protesting companies jointly requested an extension to February, which the commission granted. ■

FERC says SPP has partially complied with proposed revisions to its planning reserve margin methodology. | *WER Architects-Planners*

SPP News

SPP Shares Concerns over EPA's GHG Rule

By Tom Kleckner

SPP told its members May 20 that EPA's final rule curbing greenhouse gas emissions from power plants could negatively affect the nation's ability to provide reliable service during the "swift" transition from fossil fuels to renewable energy.

In a *statement*, the grid operator expressed concern about how Rule 2023-0072, finalized in April, will affect its region's ability to maintain resource adequacy and ensure reliability. (See *EPA Power Plant Rules Squeeze Coal Plants; Existing Natural Gas Plants Exempt*.)

"SPP is concerned that limited technological and infrastructure availability and the compliance time frame will have deleterious impacts including the retirement of, or the decision not to build, thousands of MW of baseload thermal generation," the RTO said. "If sufficient flexible thermal resources are not available to play their critical roles in SPP's resource mix, SPP's ability to maintain regional reliability will be directly impacted."

SPP noted the final rule's emissions limits for existing coal and new gas generation are based on EPA's finding that carbon capture and sequestration (CCS) technology is a viable "best source" of emissions reduction. It argued that CCS has not yet been "adequately demonstrated at the required capture rate" and will not be "widely available and practicable" to meet the agency's 2032 compliance time frame.

The grid operator also said it is concerned about the availability of gas infrastructure that will be needed for EPA's assumption that a natural gas co-firing option would be available for existing coal units that retire before 2039. Its 2023 loss-of-load expectation study indicated that it would need as much as a 50% winter season planning reserve margin to maintain a one-in-10 LOLE, SPP said.

SPP is concerned EPA's final GHG rule will hasten the retirement of thermal resources. | *Basin Electric*

"A PRM of that magnitude would require a significant amount of new capacity to be added in a short time frame," the RTO said. "The study and its projected increase in PRM did not consider the additional at-risk generation that may retire and not be adequately replaced in a relatively short time frame resulting from the compliance time frames."

SPP filed comments in EPA's rulemaking and joined with other grid operators to file joint comments.

MMU Releases Market Report

SPP's Market Monitoring Unit (MMU) said the return of natural gas prices to a "more normal" range and wind generation's increasing role in the markets highlighted its annual *State of the Market report* for 2023.

The MMU said gas prices dropped from an average of \$5.83/MMBtu to \$2.16/MMBtu at the Panhandle Eastern hub, down 63%, and were the largest contributor to a decrease in energy prices. Average day-ahead prices last year decreased 46%, from \$48/MWh in 2022 to \$26/MWh last year, and real-time prices were off 47%, from \$44/MWh to \$24/MWh.

Wind generation continues to play an increasing role in SPP's markets, with 33.7 GW of nameplate wind capacity producing 37% of the RTO's generation in 2023, more than any other resource. At the same time, that has produced challenges that include the increasing variability and uncertainty of supply, out-of-market actions to ensure system reliability, higher make-whole payments and negative prices, the MMU said.

However, the Monitor said the addition of new wind resources has slowed. Just under 1,700 MW of nameplate capacity joined the market after 1,500 MW of capacity was added in 2022. Three years ago, 3,200 MW of capacity was added.

The Monitor made two new recommendations: Improve the uncertainty product design to ensure the procurement of adequate rampable capacity; and ensure planning, markets and operational processes appropriately consider large loads' integration.

The MMU will host a webinar to discuss the report at 1 p.m. June 4. *Registration* is open on the SPP website. ■

Company News

Iberdrola to Take Full Ownership of Avangrid

Spanish-based Group Already Owns 82% of US Energy Company

Iberdrola is moving to acquire the 18.4% stake in Avangrid that it does not already own.

The Spanish-based multinational utility operator *said May 17* that this is a growth strategy: It wants to expand its presence in markets with strong credit ratings and its exposure to regulated businesses such as networks.

The $2.55 billion deal is subject to approval by shareholders, FERC and utility regulators in Maine and New York. Upon completion, which is anticipated in the fourth quarter, Iberdrola will seek to delist Avangrid shares from the New York Stock Exchange.

Avangrid is headquartered in Orange, Conn. It has approximately $45 billion in assets and 8,000 employees, mainly in renewables and networks. Its operations include eight electric and natural gas utilities in New York and New England serving more than 3.3 million customers.

Avangrid's headquarters in Orange, Conn. | *Iberdrola*

Iberdrola is based in Bilbao, Spain, and is the largest European electrical utility by market capitalization. Its assets on five continents are valued at more than 150 billion euros; its 2023 installed capacity was 62,883 MW; its power lines stretch 1.28 million km; and it employs more than 42,000 people.

Both companies claim leadership roles in the clean energy transition.

Avangrid has 8.7 GW of renewable capacity installed in 24 states and is a 50/50 partner in the first large-scale U.S. offshore wind farm, Vineyard Wind 1, now under construction. Iberdrola is pursuing a renewable portfolio totaling 100 GW.

The acquisition works out to $35.75/share, an increase from the original offer of $34.25. That represents an 11.4% premium over the closing price of Avangrid stock on March 6, the last unaffected trading day before Avangrid announced it had received Iberdrola's unsolicited offer.

Avangrid said its board of directors unanimously approved the agreement. ■

— John Cropley

National/Federal news from our other channels

Benefits of Revised Federal Offshore Wind Rule Analyzed — NetZero Insider

FERC Accepts NERC's New Cybersecurity Standard — ERO Insider

NERC Says IBR Work Proceeding as Planned — ERO Insider

Mid-Atlantic news from our other channels

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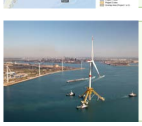
BOEM FEIS Cites 'Major' Impact from NJ OSW Project — NetZero Insider



Strategy Offered for Success of Future West Coast OSW Sector — NetZero Insider

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

Company Briefs

Mountain Valley Pipeline Bumps Planned In-service Date to June

Developers of the Mountain Valley Pipeline have revised their planned in-service date for the 303-mile natural gas project, saying they now hope to begin operating it in "early June."

On April 22, the pipeline's joint venture company sent a request to FERC to authorize the pipeline's operation by May 23, with a goal of placing it into service by June 1. Last week, the company sent a letter to FERC changing its targeted in-service date to "early June," citing "the extended construction duration to achieve weld-out, which has been associated with weather and environmental protection."

More: *Cardinal News*

Zachry Files for Bankruptcy, Plans to Exit $10B LNG Project

Zachry Holdings is seeking Chapter 11 bankruptcy protection for itself and 20 subsidiaries to allow it to make a "structured exit" from its partnership to build a $10 billion LNG terminal in Sabine Pass, Texas, the company announced last week.

CEO John B. Zachry described "significant challenges and disruptions," beginning with the COVID-19 pandemic and now "international geopolitical issues" that have resulted in "significant financial strain while meeting targets and keeping the project appropriately staffed."

Work at all of Zachry's other job sites will continue without interruption.

More: *San Antonio Report*

Amazon Adds 150-MW Solar Farm to PPA Portfolio

Amazon last week said it has entered into power purchase agreements to offtake all electricity from the 150-MW Fox Squirrel Solar Phase 1 plant in Ohio.

The company's commitment was announced in a joint press release by EDF Renewables North America and Canada's Enbridge, who each own half of the project.

The solar farm will be expanded to reach 577 MW by the end of the year.

More: *Renewables Now*

Nissan Delays Shift to EVs at Mississippi Factory

Nissan last week said it is postponing a push to build new EVs at its Canton, Miss., factory over concerns of demand.

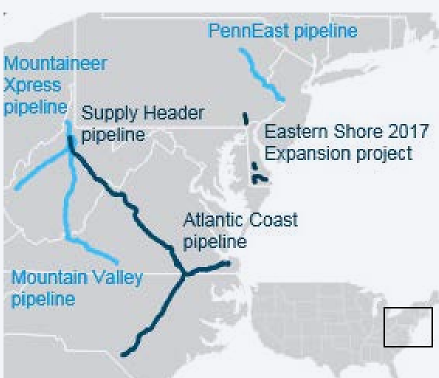
Currently Nissan sells two EV models in the U.S. but had announced plans to build five new models in Canton.

"We are adjusting the timeline for the introduction of these five new models to ensure we bring the vehicles to the market at the right time, prioritizing in line with customer demand and maximizing the opportunity for our brands and supplier partners," Nissan said in a statement.

More: *CNN*

Federal Briefs

Supreme Court Denies Appeal of Mountain Valley Pipeline Case



The U.S. Supreme Court last week declined to weigh in on the question of whether the Mountain Valley Pipeline can take private land for its project.

Without comment, the court denied a request from six property owners that it hear their challenge of the company's use of eminent domain to forcefully acquire easements through their land for the natural gas pipeline. The landowners argued that Congress improperly delegated its power to seize private property to FERC. After finding there was a public need for the pipeline, FERC then passed its eminent domain authority on to Mountain Valley.

More: *The Roanoke Times*

Republicans Press Granholm About Pause in LNG Export Permits

House Republicans last week grilled Energy Secretary Jennifer Granholm on the Biden administration's pause on LNG exports and accused the administration of halting new permits for political gain.

During a House Oversight and Accountability Committee hearing, Rep. Pat Fallon (Texas) said he was perplexed the U.S. would pause natural gas exports when other countries such as China and Russia have not made the same commitment to cleaner energy sources. Rep. Clay Higgins (La.) said that under the Natural Gas Act, the Energy Department has to issue permits unless it finds that it is not in the public interest.

Granholm said the point of the assessment, which she said is slated to wrap up early next year, was to find out whether exporting natural gas to foreign countries was in the public interest.

More: *The Washington Times*

FERC Grants Extension for Gulf LNG Import Terminal

FERC last week awarded Gulf Liquefaction and Gulf Energy an extension to construct their Gulf LNG liquefaction project.

The companies requested a five-year extension In February, saying the COVID-19 pandemic and litigation with import customers had affected their ability to meet the project's deadline. The project now has until July 16, 2029, to be completed and operational.

More: *LNG Prime*

State Briefs

CONNECTICUT

Solar Farm Developer Issued Stop-work Order

New Windsor Supervisor Steven Bedetti last week said the town has issued AHC Development Construction Consulting a stop-work order after the solar developer clear-cut dozens of trees that were supposed to be left as a buffer.

AHC President Keith Libold said the company's contractor mistakenly cut trees that were supposed to be left and that they have submitted a new proposal that includes replacing trees in the original, agreed-upon buffer zone.

More: *News 12 Connecticut*

IOWA

Tornado Topples Several Turbines

Multiple tornados ripped through the state May 21, with one toppling several 250-foot wind turbines in the Prescott area.

Wind farms are built to withstand tornadoes, hurricanes and other powerful winds. According to the U.S. Department of Energy, turbines are designed to shut off when winds exceed certain thresholds, typically around 55 mph. They also lock and feather their blades, and turn into the wind, to minimize the strain.

More: *The Associated Press*; *AccuWeather*

LOUISIANA

PSC Approves Entergy's Plan to Add 3 GW of Solar

The Public Service Commission last week approves Entergy Louisiana's request to add up to 3 GW of solar power to its generation portfolio.

The initiative is part of the utility's plans to achieve net-zero carbon emissions by 2050.

"This approval underscores our commitment to meeting operational and sustainability needs, driving economic development, and protecting the environment," Entergy Louisiana CEO Phillip May said in a statement.

More: *Entergy*

MASSACHUSETTS

Eversource Wraps up Upgrade of Tx Program

Eversource Energy last week said it has completed the first phase of the Cape Cod Solution Transmission Program, which requires rebuilding of the grid to enhance resilience and reliability while supporting the infrastructure needed to connect offshore wind projects.

Phase 1 of the Cape Cod Solution is one of only two transmission projects underway in New England that will allow for the interconnection of offshore wind and included the expansion of Eversource's West Barnstable substation and the installation of a 12.5-mile transmission line.

More: *Renews*

MINNESOTA

Legislation on Permitting, Community Solar Credits Passed

Democrats overcame a split within the party last week to pass legislation that would cut red tape for wind, solar and transmission projects and uphold a Public Utilities Commission decision to shrink bill credits.

The legislation was part of a larger package that included agriculture policy and spending. Senate Democrats backed the permitting legislation, while those in the House of Representatives chose to use that as leverage to change community solar credits. The final deal included most of the Senate permitting plan, including a transfer that will give the PUC more staff.

The House was able to add extra staff at the Department of Commerce to help analyze energy projects, as the agency acts as a public-interest watchdog at the PUC. The bill also does not include a study of small nuclear reactors and questions of long-term nuclear waste storage.

More: *Star Tribune*

State Investment Board Passes Climate Resolution

The State Investment Board last week passed a resolution stating it will consider longer-term risks to pension investments such as climate change.

Environmental, social and governance has been part of the state's investment strategy for years. Last week, the investment board passed a resolution to "consider all material risks and opportunities" of its investments, with state leaders underlining their interest in considering climate change risks.

Board of Investment Executive Director Jill Schurtz said the state has preferred to take an active role as a shareholder in pushing companies to change their practices, rather than divesting.

More: *Star Tribune*

NEW MEXICO

Climate Investment Center Becomes State's 1st Green Bank

The New Mexico Climate Investment Center, a nonprofit aiming to help equitably finance the state's clean energy transition, was unveiled last week.

The center will finance clean energy technologies and the use of those technologies and is designed to increase climate resilience. Loans will be used to develop clean energy with a focus on low-income, disadvantaged and tribal communities.

More: *The Albuquerque Journal*

WYOMING

Siting Council Approves Large Solar Farm

The Industrial Siting Council last week greenlit the 771-MW Cowboy Solar Farm in Laramie County.

It will be the state's largest solar project and include 269 MW of battery storage. It will be constructed on private lands, with construction set to begin next March.

More: *Casper Star-Tribune*