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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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COVER: Onshore wind projects are found across the U.S., except the Southeast. | *DOE*

RTO Insider
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Counterflow

By Steve Huntoon

Vampire Power

By Steve Huntoon

This ad from the local utility caught my eye. It's from Delmarva, a subsidiary of Exelon, the largest utility company in the country.[1] The idea is to unplug appliances not in use so as not to use electricity in "standby" aka "sleep" aka "idle" aka "inactive" aka "phantom" aka "always-on" mode. Vampire power.

Who wouldn't want to learn more? So I went to *delmarva.com/peakmd*, and from there to the details page, where the first specific tip is: Unplug unused electrical devices when you leave a room. Chargers use energy when left plugged in, even after your device is fully charged.[2]

Chargers? Really?

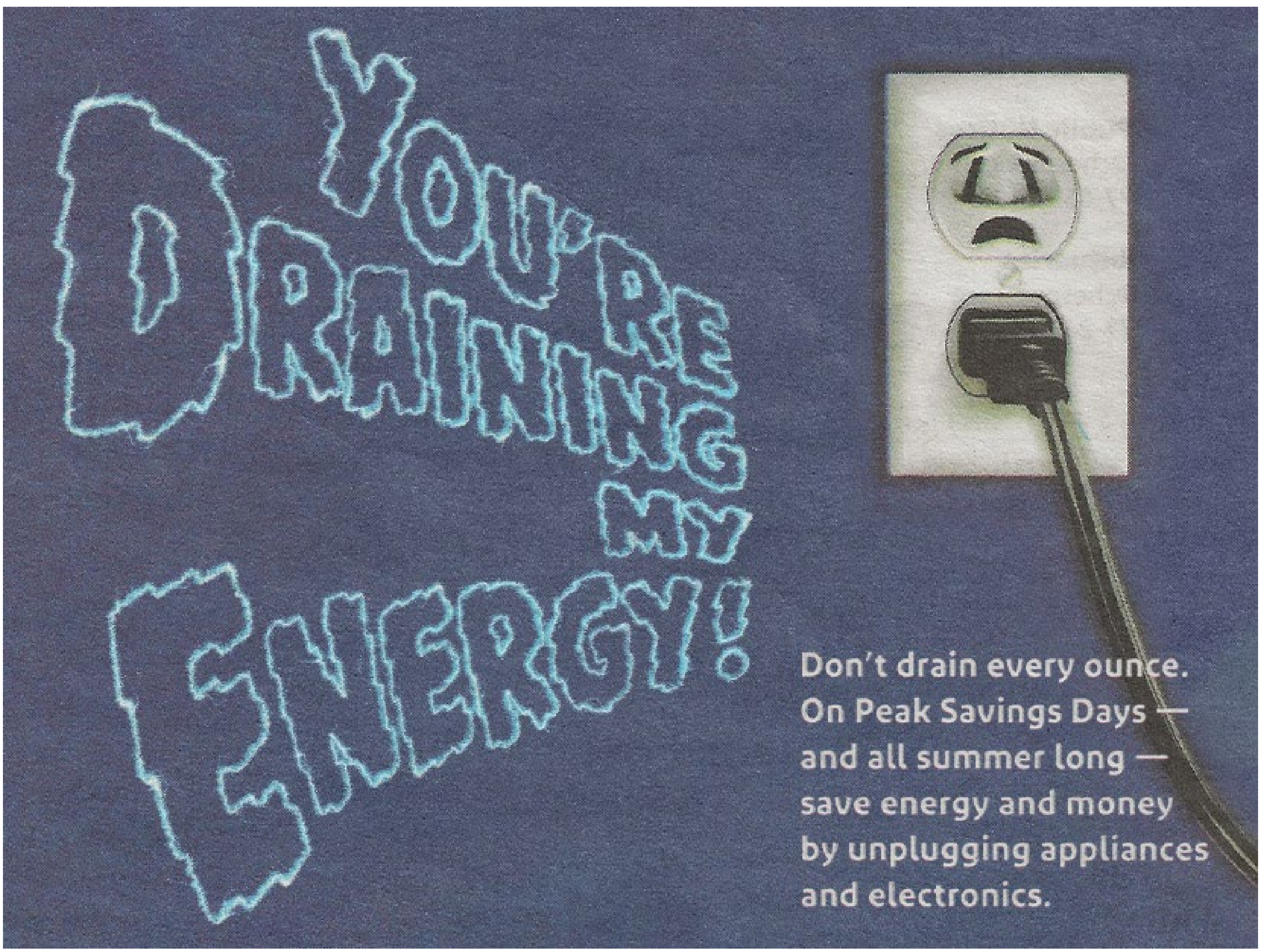
With a little Googling I came across an amusing article putting this premise to the test with a power meter.[3] Each charger registered 0 watts. Adding various chargers to a power strip didn't register more than 0 watts until the 6th charger. The reading with 6 chargers? 0.3 watts. As the article points out, that's 2.6 kWh/year which at 13 cents/kKh is 34 cents a year. About 6 cents a charger a year.

Not to scoff at saving 6 cents a year from unplugging/plugging a charger every day for a year. But perhaps there are bigger vampires to slay.

OK, What Bigger Vampires to Slay?

It's said a zillion times on the internet that the Department of Energy reports that homeowners can save anywhere between $100 and $200 each year by unplugging devices not in use.[4] I can't find this DOE report (if you can please send me the link).[5]

It's possible that this range attributed to DOE might have its origin in a Natural Resources Defense Council study, which estimated average residential vampire power costs at



| Delmarva Power & Light Co.

Counterflow

By Steve Huntoon

$165 per year.[6]

The study put power meters on individual electronic devices at a sample 10 homes in California. When you look at the details (Appendix C), you find that the big usages in "inactive" devices are for things like fishpond/aquarium pumps, refrigerators, furnaces, hot water recirculation pumps,[7] GFCI outlets, networking equipment (modems, routers), printers, alarm clocks, irrigation systems, garage door openers and security systems. In other words, not stuff you unplug (assuming you even could). By the way, there were an average of 65 devices per household using vampire power, so one can imagine the hassle of plugging/unplugging these devices on a daily or other routine basis (again, assuming you would or could).

One of the few things you might unplug when not using is set-top boxes. (TVs themselves consume very little power in stand-by mode.)[8] Is someone going to make a habit of unplugging set-top boxes? Waiting for a reboot every time it's plugged back in? Missing a show you wanted to record because you forgot to plug it back in? I think not.

In short: Big savings from unplugging vampire power are as much a fantasy as, well, vampires.[9]

Meanwhile Back at the Ranch

Missing from the Delmarva list is an easy way to significantly reduce electric usage: LED lighting. The math is something like 1,105 kwh/year for average residential lighting,[10] times 13 cents/kwh, times 84% for the reduction in electric usage from switching from incandescent to LED lighting, for about $120 per household. While LED lighting has dramatically increased since 2015, it's dominant in only half of U.S. households, so there's a long way to go.[11]

And LED lighting pays for itself in equipment savings alone (ignoring the electric bill savings) because it outlasts an equivalent incandescent by maybe 20 times while costing maybe two times as much.

Wrapping Up

There is reason to doubt the value proposition for customers to fund public service advertising by utilities. But where it happens, the least to ask is that utilities promote effectual and hassle-free ways to reduce electric usage instead of ineffectual and hassle-ladened ways. ■

[1] https://www.exeloncorp.com/company/about-exelon

[2] https://www.delmarva.com/WaysToSave/ToolsAndResources/Pages/EnergySavingTips.aspx.

[3] https://www.howtogeek.com/231886/tested-should-you-unplug-chargers-when-youre-not-using-them/

[4] https://questionanswer.io/does-unplugging-microwave-save-money/

[5] I emailed the DOE/Berkeley Lab expert on standby power but didn't get a reply.

[6] https://www.nrdc.org/sites/default/files/home-idle-load-IP.pdf

[7] It appears these generally come with sensors and/or timers that reduce electric use. https://homeinspectorsecrets.com/hot-water-recirculating-pumps/how-recirculating-pumps-work/

[8] https://www.latimes.com/nation/la-na-power-hog-20140617-story.html

[9] I'm not suggesting that makers of electronic devices shouldn't reduce vampire power. There's been progress on that front from voluntary and mandatory standards, and it should continue.

[10] https://www.eia.gov/consumption/residential/data/2015/c&e/pdf/ce5.3a.pdf (data is for 2015, before large penetration of LED lighting).

[11] https://www.ny-engineers.com/blog/us-energy-information-administration-47-of-homes-use-led-lighting

FERC/Federal News

Wind Energy Market Sees Rising Penetration, Falling Value, DOE Reports

By K Kaufmann and John Norris

Like solar, wind generation in the U.S. faces a challenge of rising penetration and falling value on the grid.

Wind energy power purchase agreement prices are still trending below natural gas prices, according to the Department of Energy's 2022 *Land-Based Wind Market Report*. But "the regions with the highest wind penetrations (SPP at 35%, ERCOT at 24% and MISO at 12%) have generally experienced the largest reduction in wind's value relative to average wholesale prices," the report says.

For example, the wholesale market value of wind in SPP in 2021 was $19/MWh versus $46/MWh for "24/7 flat profile" generation.

DOE released three wind energy market reports on Aug. 16 — one each on land-based, offshore and distributed resources — which together provide a view of the push and pull of forces now shaping the growth of the industry in the U.S.

The land-based report shows that while the solar industry is addressing intermittency issues with a growing number of hybrid solar and storage deployments — 67 new projects in 2021 — only two wind-and-storage projects were added to the grid last year.

Further, wind-and-storage hybrids are not providing the same capacity and flexibility as solar-and-storage. "The average storage duration of these [hybrid wind] projects is 0.6 hours, suggesting a focus on ancillary services and limited capacity to shift large amounts of energy across time," the report says.

Offshore

A similar push-and-pull can be seen in the unprecedented $4.37 billion paid for six offshore wind leases in the New York Bight auction in February. While the sale was widely seen as demonstrating the intense interest in offshore development, it also triggered concerns about the impact of those high prices — estimated at $763/kW — on consumers' electricity bills, according to DOE's 2022 *Offshore Wind Energy Market Report*. (See *Fierce Bidding Pushes NY Bight Auction to $4.37 Billion*.)

In response, the U.S. Bureau of Ocean Energy Management changed the auction rules for its May offshore auction, for two sites off the coast of the Carolinas, which sold for a modest combined total of $315 million. (See *North Carolina OSW Auction Nets $315 Million*.)

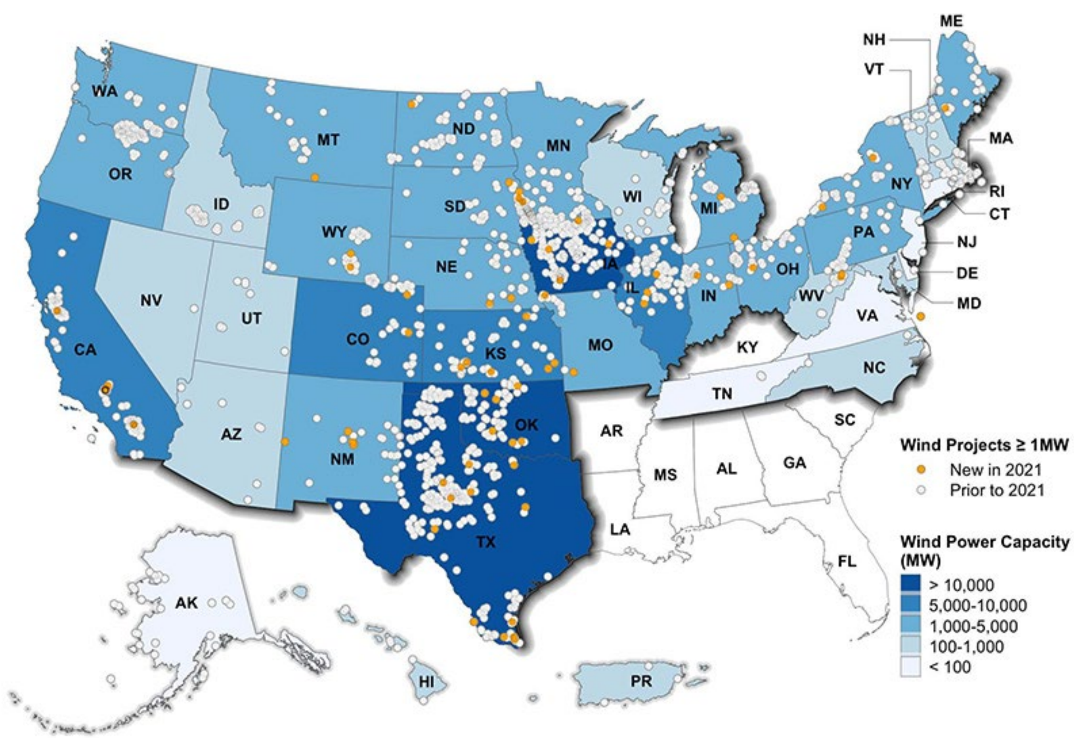
The "multifactor" bidding rules discounted prices by providing credits for up to 20% of the total sale amount to bidders committing to workforce or supply chain development as part of their projects. A similar multifactor approach will be used for upcoming Pacific Coast offshore wind auctions, the report says.

Driving down costs will be a continuing challenge for offshore wind, with DOE reporting global levelized costs for fixed-bottom projects in 2021 ranging from $75/MWh to $116/MWh, versus a U.S. average of $32/MWh for onshore wind. Adding to cost pressures in the U.S., the report says, "the [offshore] industry will need to tackle new technical challenges, such as hurricane survival, deeper water and lower average wind speeds."

Onshore

While the U.S. onshore wind market continues to grow, with a total capacity of 136 GW by the end of 2021, the country still lags behind a number of European countries — including Denmark, Spain, Germany and the U.K. — which each get more than 20% of their power from wind.

2021 was also a year of contraction for the U.S. market, according to the land-based report. New onshore capacity grew by 13.4 GW last year — a 20% drop from the 16.8 GW installed in 2020 — but still enough to keep wind as the second-largest source of new generation on the U.S. grid. Solar was No. 1 at 45% of new generation with wind power following at 32%.



Onshore wind projects are found across the U.S., except the Southeast. | *DOE*

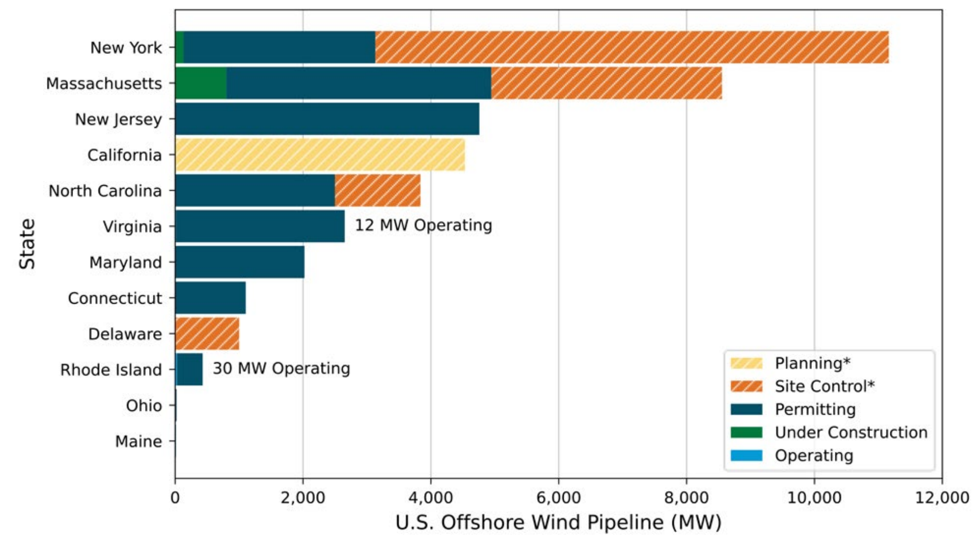
FERC/Federal News

The domestic supply chain also contracted, with blade manufacturing taking a 50% nosedive as three U.S. manufacturing plants closed or idled, the report says. Like the solar and storage industries, wind relies heavily on imports, which were worth $3.1 billion last year, with Mexico, Spain and India the country's key suppliers.

The U.S. market also relies on four turbine manufacturers, with only one — General Electric — homegrown, according to DOE. The others are Vestas, Siemens Gamesa Renewable Energy and Nordex.

Like solar, domestic wind is being slowed by projects caught in RTO and ISO interconnection queues. DOE reports 247 GW of wind are currently waiting for interconnection.

More promising, in terms of future growth, the market is diversifying in terms of who owns, sells or is buying wind-generated power. Utilities accounted for 44% of new wind power on the grid last year, but direct retail purchasers, including corporations, were close behind, with 35%. Merchant or quasi-merchant projects, with revenues tied to short-term contracts or wholesale spot markets, made up another 7%.



Capacity for "Permitting" and "Site Control" categories are assigned to the state where the wind energy area (WEA) is geographically located. All other categories are assigned to the state where the power will be delivered. | *DOE*

Distributed Wind Energy

DOE also reported its latest data on the *distributed wind energy* fleet, which totals 89,000 turbines with a nameplate capacity of 1,075 MW.

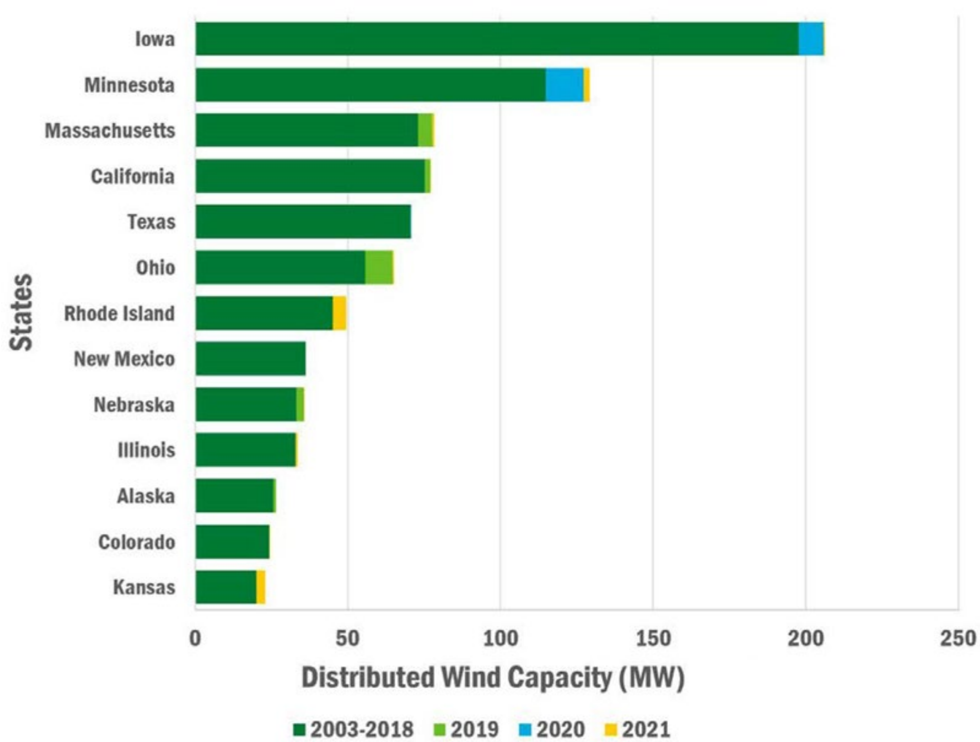
In 2021, 15 states added 1,751 turbines totaling 11.7 MW, representing a $41 million investment, about 75% of which was installed in Rhode Island, Kansas and Minnesota. That was a drop from the 21.9 MW ($44 million) added in 2020 and 20.4 MW ($59 million) added in 2019.

Of the 11.7 MW added last year, 8.7 MW came from projects using large-scale turbines (greater than 1 MW), while 1.2 MW came from mid-sized turbines (101 kW to 1 MW) and 1.8 MW came from small wind turbines (up to 100 kW). DOE said small turbine manufacturers are reporting that potential customers are increasingly expressing interest in microgrids or hybrid systems.

Distributed wind energy caters to a diverse group of customers, including military operations, municipal water systems, prisons, parks and tribal governments. In 2021, utility customers accounted for 56% of the total distributed wind capacity, while agricultural customers accounted for 56% of the total number of new projects installed. Between 2012 and 2021, 90% of the distributed wind projects were interconnected for on-site use, while the remaining 10% served local loads on distribution systems.

Although distributed wind occupies a tiny niche now, the National Renewable Energy Laboratory's *Distributed Wind Energy Future Study* says it has an economic potential of 919 GW behind the meter and 474 GW in front of the meter.

"The projections increase substantially in a 2035 scenario that includes more policy support, namely the extension of the federal investment tax credit and relaxed siting conditions," DOE said. ■



Iowa and Minnesota, which have strong wind resources and active project developers, have received a significant number of U.S. Department of Agriculture Rural Energy for America Program wind grants, DOE says. | *DOE*

Southeast

SACE Urges FERC Inquiry into Proposed TVA Gas Plant

By Amanda Durish Cook

TVA's Cumberland Fossil Plant is slated for retirement in 2030. | *TVA*

The Southern Alliance for Clean Energy (SACE) has protested with FERC that the Tennessee Valley Authority's justification behind a new gas plant's construction is faulty, urging the commission to conduct its own assessment into the resource's need.

TVA has proposed a natural gas plant and a 32-mile pipeline to replace its coal-fired Cumberland Fossil Plant northwest of Nashville. The alliance said the federal agency would be better served with a blend of large-scale and distributed solar, wind and storage resources and energy efficiency measures.

SACE's protest was registered in a docket related to Tennessee Gas Pipeline Co.'s request for FERC permission to build the gas pipeline. The alliance was among several public-interest groups that urged TVA in June to rethink its plans after the agency filed its environmental impact statement (CP22-493). (See *Nonprofits Urge TVA to Reconsider Gas-fired Options*.)

SACE *repeated* its position that the draft EIS isn't a reliable document and lacks a transparent analysis to support it. The alliance said FERC should assess other alternatives. It said the draft clings to an outdated and rosy natural gas price forecast and said it is based on TVA's 2019 integrated resource plan, which used assumptions made from 2016 to 2018 and predates President Joe Biden's executive order that calls for net-zero carbon emissions in the electric sector by 2035.

"Were TVA to build a new carbon-emitting gas CC at Cumberland by 2026, with no plans for capturing the carbon, it will immediately become a stranded asset in less than a decade and thus add to the utility's costs that must be borne by the 10 million people it serves," SACE said.

It also said the federal agency didn't consider the possibility of energy efficiency programs offsetting some demand or importing wind power into its territory.

"Since TVA is currently lagging the Southeast in energy efficiency savings, a region that lags the country in energy efficiency savings, and the National Renewable Energy Laboratory estimates there is substantial energy efficiency potential in just Tennessee alone, it is absolutely reasonable to assume that energy efficiency would be a cost-effective addition to a clean energy portfolio replacement," SACE argued.

The alliance also suggested that TVA executives may have a conflict of interest, noting they receive millions in bonuses tied to the availability of coal and gas plants but don't have any incentives attached to expanding renewable energy or energy efficiency.

SACE said there is no evidence that TVA took any steps to meaningfully evaluate other Cumberland replacement plans.

"These actions could have included issuing a request for proposals for renewable energy and energy storage resources, staffing up its interconnection study department to prepare to interconnect renewable energy projects faster, identify and begin planning transmission projects to ease the integration of renewable energy projects and beginning to set up energy efficiency programs and other demand-side measures," SACE said. "TVA's actions to date make it very clear that it always intended for the gas [combined cycle] option to be its preferred option regardless of the environmental review process, and that brings the merit of its environmental review into question."

The Sierra Club and Appalachian Voices also filed protests in the docket. They said the Tennessee Gas Pipeline "can offer no reliable evidence that its only customer, TVA, will ever be able to move forward with its plans."

"The proposed power plant would emit millions of tons of greenhouse gases each year, rendering it incompatible with the President's executive orders on climate change, dependent on a volatile and increasingly expensive fuel, and more costly than an available suite of clean energy resources," the environmental advocates said.

The Sierra Club and Appalachian Voices also urged FERC to "independently evaluate the need" for Cumberland City and the pipeline and consider "clean energy alternatives that could replace both at lower cost to ratepayers." It said the commission's examination is needed because TVA lacks meaningful oversight and competition.

TVA maintains that it hasn't made a final determination regarding its natural gas plant plans.

"TVA has not made any decisions about the future of that plant nor replacement options, pending completion of the [National Environmental Policy Act] process later this year," spokesperson Ashton Davies said in a statement to *RTO Insider*.

TVA stressed that it is not involved with the construction of the pipeline or its permitting and regulatory process. Davies said the utility would merely be a customer of the pipeline should it elect to construct a gas-fired plant.

"TVA is supportive of the project as it would be a likely source for natural gas, should TVA choose that option to replace capacity at Cumberland Fossil Plant," Davis said. ■

CAISO/West News

Western Power Pool Board Approves WRAP Tariff

By Hudson Sangree

The Western Power Pool's board last week approved a tariff to implement its Western Resource Adequacy Program, an initiative intended to ensure that participants across much of the Western Interconnection have sufficient capacity amid a changing resource mix.

WPP said it is planning to file the WRAP *tariff* with FERC by this Wednesday, followed by a 30-day comment period.

The program, which already has 26 participants in an area reaching from British Columbia to Arizona and east to South Dakota, is the "first regionwide reliability planning and compliance program in the history of the West," WPP said in a news release last Wednesday, the day after the board's approval.

The tariff approval "is another major milestone leading us closer to making this first-of-its-kind program a reality," WPP CEO Sarah Edmonds said in the news release. "Resource adequacy is an urgent and immediate challenge, especially in the West, and requires this type of regionwide approach to address it."

Earlier this month the WRAP's Resource Adequacy Participant Committee (RAPC), consisting of a representative from each participant, also approved the draft tariff. The 74-page document lays out the program's governance structure, including the roles of the RAPC, a Committee of State Representatives (COSR) and a Program Review Committee.

It describes in detail the program's two main "time horizons," a forward-showing program requiring participants to show they have sufficient capacity months in advance of summer and winter peaks, and an operational program, focused on the allocation of resources in real-time and day-ahead time frames.

And it addresses issues such as participation rates, financial penalties for resource deficiencies and failures to deliver, and dispute resolution.

Since 2020, WPP has been developing the WRAP, an initiative conceived to address concerns that Northwest utilities have been increasingly and unknowingly drawing on the same shrinking pool of reliability resources. But interest in the effort spread quickly to other areas of the West. In a move that signified its expanding reach across the Western Interconnection, the Northwest Power Pool *rebranded* itself as the Western Power Pool earlier this year.

The WPP is slated to launch a "nonbinding" iteration of the WRAP in the third quarter of this year and a binding phase with penalties sometime in 2024. Initially, the absence of enforcement and penalties will shield the program from FERC oversight, giving members additional time to iron out wrinkles and finalize its design.

WPP last year selected SPP to develop and operate the technical aspects of the WRAP, providing the market's forward-showing functions, modeling and system analytics, and real-time operations.

Some in the West have speculated the WRAP could serve as a springboard for the eventual development of an RTO, one that would compete with CAISO's stalled regionalization efforts and the ISO's well-established Western Energy Imbalance Market. SPP has been using its new foothold in the West through the WRAP to build interest in its Markets+ program, a collection of services that stops short of a full RTO but could eventually develop into one. (See *SPP Continues to Build on Markets+ Offering*.)

Anticipating possible future requirements, WPP has already moved to restructure its governance and prepare to adopt some elements of an RTO, such as the appointment of an independent board of directors. WPP also established the COSR to ensure that utility regulators have a voice in discussions related to the WRAP.

The tariff appears to address the eventuality, saying: "Subject to the limitations and prohibitions imposed under Section 3.4 of this tariff, if the Board of Directors votes to file at FERC to expand the WRAP to include market optimization or transmission planning services, WPP will initiate a formal process with COSR and other stakeholders to conduct a full review of governance structures and procedures, including the role of states."

'Collaboration and Transparency'

The WPP published the WRAP draft tariff last month, inviting stakeholders to comment during a public webinar on July 25. Feedback from that session was incorporated into the updated draft that the board approved.

"Throughout this process we have remained committed to collaboration and transparency," Edmonds said. "For three years, we have worked with regulators, participants and stakeholders to shape the program. We've listened to stakeholder voices, embraced their comments, and refined the program design and the tariff itself to get to a solution supported by all participants."

The Northwest Power Pool changed its name this year to Western Power Pool to reflect its expanding Western Resource Adequacy Program. | *NWPP*

FERC's approval of the tariff would allow WPP to set rates and terms of participation and to make governance changes.

"WPP is hoping for a final order from FERC giving approval by the end of this year," the group said in the news release. "The WRAP team also intends to confirm commitments from potential participants for the next phase of their participation by mid-December."

WRAP Stage 1 participants include Arizona Public Service, Avangrid, Avista, Black Hills Energy, Basin Electric Power Cooperative, Bonneville Power Administration, Calpine, Chelan PUD, Clatskanie PUD, Douglas PUD, Eugene Water and Electric Board, Grant PUD, Idaho Power, NorthWestern Energy, NV Energy, PacifiCorp, Portland General Electric, Powerex, Puget Sound Energy, Seattle City Light, Snohomish PUD, Shell Energy, Salt River Project, Tacoma Power, Turlock Irrigation District and The Energy Authority, which is representing seven Washington and Oregon publicly owned utilities. ■

CAISO/West News

CPUC Postpones NEM Decision Amid Pressure

By Hudson Sangree

The California Public Utilities Commission on Thursday approved a one-year postponement of a decision in its net energy metering rulemaking, as parties on both sides of the issue argued that the recently signed Inflation Reduction Act supports their views on rooftop solar credits.

The CPUC passed the *order* extending the deadline for its decision in a unanimous vote on its 35-item consent agenda. Commissioners did not discuss the move, despite its significance and the controversy that has engulfed the CPUC ever since it issued a proposed decision in December to slash solar credits and charge owners for grid participation in a new net energy metering (NEM) tariff. (See *California PUC Proposes New Net Metering Plan*.)

"An extension of the statutory deadline until Aug. 27, 2023, is necessary to allow adequate time to complete this proceeding," the order said, citing the need to digest a flood of comments and consider alternative approaches.

The proposed decision was released on Aug. 15. (See *CPUC to Delay Net Metering Decision for a Year*.)

As in many of its voting meetings this year, the bulk of the CPUC's session Thursday consisted of public comments on the NEM *proceeding*, mainly from homeowners upset about the proposed changes.

Their latest target was a filing by the state's three large investor-owned utilities contending that the extension of federal credits for rooftop solar in the IRA made the state's generous credits unnecessary.

"The Inflation Reduction Act, and more specifically the extension of the 30% tax credit for both non-residential and residential solar projects, is directly relevant to the modeling of a successor net energy metering tariff in this proceeding," Pacific Gas and Electric, Southern California Edison and San Diego Gas & Electric said in their Aug. 19 joint filing, which asked the CPUC to take official notice of the new law.

The federal credit "reduces the cost of solar adoption, thereby reducing the payback period for customers benefitting from the tax credit," the IOUs said.

The utilities have pushed to reduce the long-time state credits that reimburse residential and non-residential solar owners for energy exported to the grid. Customers receive credits at full retail rates, which are now much higher than utility solar costs.

The utilities argued the scheme shifts $4 billion in costs from those who cannot afford rooftop solar to those who can.

In her December proposed decision, Administrative Law Judge Kelly Hymes agreed with the argument, saying the cost shift "disproportionately harms low-income ratepayers."

Opponents of that proposal, however, contend that more than 1.3 million rooftops in California now have solar arrays, thanks in large part to the generous NEM credits. On Thursday, commenters took issue with the IOUs' suggestion that the IRA made California's incentives less necessary.

The state wants to reduce incentives just when Congress clearly indicated the importance of rooftop solar to the nation and when incentives are needed more than ever, they said.

"Your mindset of allowing new solar taxes to be charged and lowering the solar production credits is just wrong," David Delphos of Orange County told the CPUC. "There is nothing in the new Inflation Reduction Act of 2022 that can justify any new California solar taxes or justify lowering the solar credits for solar system owners."

Yvette DiCarlo of San Francisco said that "PG&E is now using the Inflation Reduction Act to further justify penalizing rooftop solar.

"Meanwhile PG&E's website boasts how they own and operate 13 solar large farms in the Central Valley, far from their main customers, and how they also continue to add solar to the grid through contracts with third-party developers. They also boast adding 3,300 MW of new storage by 2024, so it's clear that PG&E treats rooftop solar as a competitive threat to be squashed." ■

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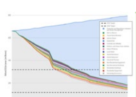
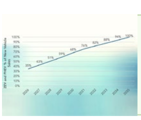
West news from our other channels



Ore. Looks to Accelerate GHG Reduction Goals — NetZero Insider

Company Looks to Build Hydrogen Projects in Eastern Ore., Wash. — NetZero Insider



Calif. Adopts Rule Banning Gas-powered Car Sales in 2035 — NetZero Insider

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

Correction: ERCOT Board Eliminated Unsecured Credit

An article in the Aug. 23 *RTO Insider* newsletter incorrectly reported that ERCOT's Board of Directors had approved a protocol change that reduced counterparties' limit for unsecured credit to $30 million from $50 million. However, the measure actually eliminated unsecured credit entirely. (See "Board Agrees to Lower Unsecured Credit Limit for Counterparties," *ERCOT Board of Directors Briefs: Aug. 16, 2022*.)

The motion's language incorporated the Technical Advisory Committee's approval of a reduction to $30 million in April, as *suggested* by its Protocol Revision Subcommittee. However, it then added "as amended by" *ERCOT comments* from March.

In the comments, staff disagreed with the reinstatement of unsecured credit limits to the nodal protocol revision request (*NPRR1112*), saying the credit limit "translates directly to a cost that must be borne by other market participants" should there be a default.

"The provision of unsecured credit therefore means that the credit risk from the market activities of some market participants is subsidized by others," staff said. "Elimination of unsecured credit will reduce the inconsistent cross-subsidization of credit exposure and provide a more level playing field for market participants."

Staff and stakeholders had also debated the measure during TAC's April meeting, when the committee voted in favor of the reduction to $30 million. (See "TAC Passes Contentious Outage Measure over Staff's Objections," *ERCOT Technical Advisory Committee Briefs: April 13, 2022*.)

ERCOT directors and stakeholders during the August board meeting | © *RTO Insider LLC*

"That was an incredibly confusing motion and could have been more clearly conveyed," TAC Chair Clif Lange told *RTO Insider*.

ERCOT General Counsel Chad Seely referred to the motion's language as "odd" before he offered it to the board for its unanimous approval.

Lange said he was told by the grid operator's staff that the motion was crafted in the manner it was presented to capture the record developed in TAC's report on the NPRR. ■

— Tom Kleckner

ERCOT News

Texas Regulators Open Energy Efficiency Docket

Jackson Debuts as 5th Commissioner; New PR Office Opened

By Tom Kleckner

AUSTIN, Texas — State regulators have opened a docket proposing changes to peak-demand reduction, energy efficiency goals and related programs following a petition from the Lone Star Chapter of the Sierra Club.

The environmental group *filed* its request with the Public Utility Commission on Aug. 17, asking it to open a rulemaking that would amend a market rule related to load management and energy efficiency goals, programs and cost-recovery mechanisms managed by the state's eight private transmission and distribution utilities (TDUs) (*53971*).

"We recognize that this proposal would require substantial changes … but believe it will be in the interests of Texas commercial and residential consumers and the larger resilience and reliability of the grid," the Sierra Club said in the filing.

The petition would double TDUs' required peak-demand goals and increase the energy efficiency of the overall savings goals for both for summer and winter, Cyrus Reed, the Lone Star Chapter's conservation director, told the PUC during its Thursday open meeting.

The Sierra Club is calling for the TDUs to meet a new peak demand goal of 0.5%, or 40% of load growth, for residential and commercial demand by 2024 and 0.7% (50% of load growth) by 2025, and that they meet both and winter and summer peak with demand-reduction programs. It also asks that utilities increase their spending on hard-to-reach and low-income programs from 10% in 2023, 15% in 2024 and 20% in 2025.

The organization designed its petition to be implemented in three phases, with goals and metrics increasing modestly in a stagger-stepped approach in 2023 through 2025.

Reed reminded the commissioners that their blueprint for a redesigned ERCOT market, released last December, included an item to look at the TDUs' energy efficiency and demand response programs. (See *PUC Narrows Options for ERCOT Market Redesign*.)

"No one's taken action yet" on that, Reed told the commissioners. He was the first of 16 Sierra Club and affiliated speakers that took advantage of the PUC's public comment agenda item Thursday to lodge their dissatisfaction with the lack of energy efficiency measures and high energy bills.

Residential customers in the ERCOT market have seen their *bills rise about 70%* over last year's, thanks to high natural gas prices, inflation and power plant weatherization costs that have been passed on to consumers. In addition, ERCOT's conservative posture and reliance on having generators available to run more often, have created more than an additional $1 billion in market costs, *according to* the Independent Market Monitor.

"We don't think the commission up to now has really centered on solutions that will help residential consumers with these rising bills," he said.

Reed noted that municipal utilities Austin Energy and CPS Energy have already met the Sierra Club's suggested goals.

The full PUC meets for the first time, with (from left) Jimmy Glotfelty, Will McAdams, Peter Lake, Lori Cobos and Kathleen Jackson. | *© RTO Insider LLC*

ERCOT News

"We think private utilities should have similar goals. You guys have a lot of room to operate," he said. "We're concerned about any solutions to the grid that's going to put the burden on residential ratepayers without offering us solutions on how to lower those potential costs through energy efficiency, demand response and distributed generation."

As they normally do, the commissioners did not respond to the comments, but they did thank the speakers for their three-minute statements.

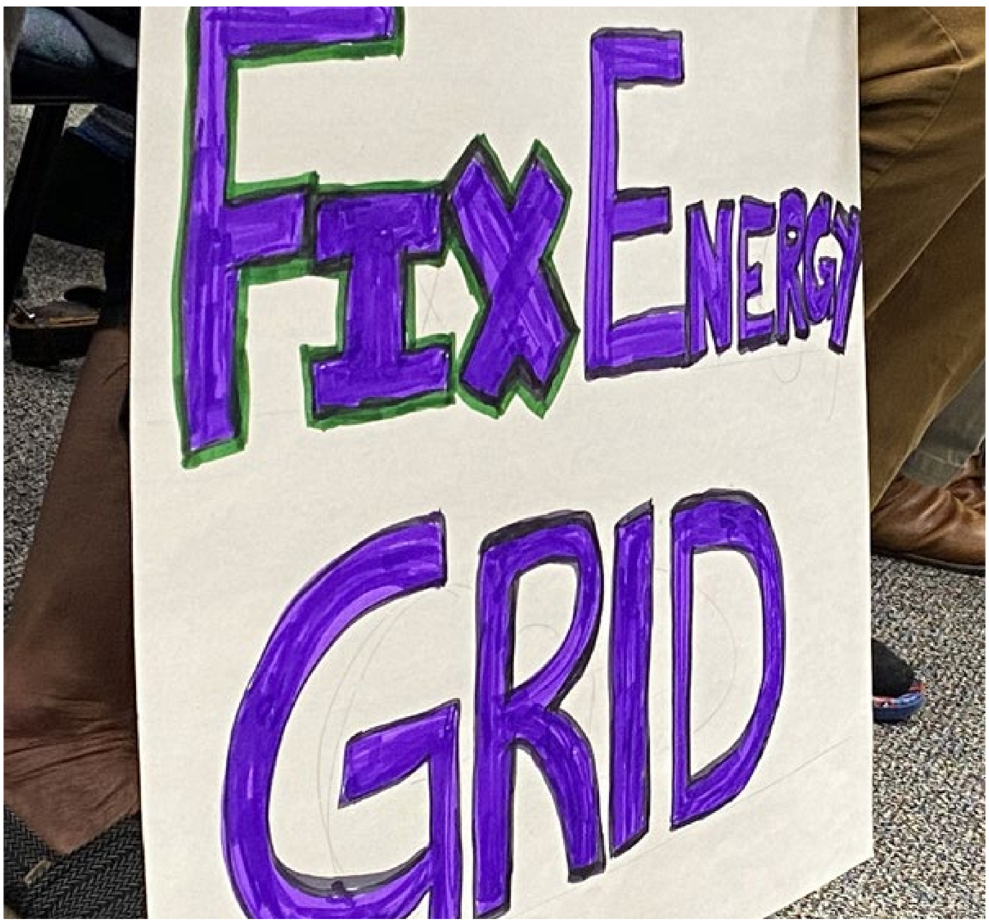
Stakeholders have until Sept. 16 to comment on Sierra Club's proposal.

First Meeting for Commissioner Jackson

The meeting marked newly minted Commissioner Kathleen Jackson's first as a member of the PUC, which now sports five members for the first time. A professional engineer and a member of the Texas Water Development Board (TWDB), she was appointed to the commission on Aug. 5 by Gov. Greg Abbott. (See *Abbott Fills out Texas PUC with 5th Member*.)

PUC Chair Peter Lake welcomed Jackson by asking her to take the lead on the commission's energy efficiency responsibilities and efforts, pointing to her involvement on water conservation while at the TWDB. Jackson is expecting to evaluate the PUC's energy efficiency policies and procedures and recommend actions to improve energy efficiency.

"Water and electricity are certainly different resources, but the principles of conservation and efficiency are very similar: Don't waste critical resources, and get the most out of every bit of your existing resources," Lake said.



Protester's sign at the PUC's open meeting | *© RTO Insider LLC*

"I really look forward to the work ahead," Jackson said. "We all know that people need a reliable water supply, and they also need a reliable power supply. I'm very much hoping that I can bring to this work effort a scientific analytical mind."

"Take me at my word, she's a very sharp lady," Lake said.

Jackson was also welcomed by Reed. Sierra Club members worked closely with Jackson on water conservation issues during her time on the TWDB.

"I'm thrilled that you've been tasked with looking at energy efficiency and ... demand response issues," Reed said.

Commissioner Jimmy Glotfelty jokingly admonished the other commissioners for not wearing a tie "on our fifth commissioner's first day." The PUC has been operating under a casual summer dress code that allows male staffers to skip tying knots around their necks.

"We'll try harder next time," Lake said, noting the PUC's next meeting will be in September and business attire will return.

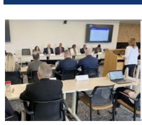
New Office of Public Engagement

The PUC is also creating an Office of Public Engagement that will provide a single point for Texans who wish to participate in electricity, water and telecommunications issues before the PUC.

Michael Hoke, who has worked with legislators and stakeholders to resolve issues under the commission's regulatory authority as its government relations director, will lead the office. When fully staffed, it will include three other staff members.

"We are constantly exploring ways we can improve and enhance assisting consumers ... in a way that emphasizes collaboration among everyone involved and ultimately benefits customers and ratepayers," Lake said. ■

South news from our other channels



Texas RE Board of Directors Briefs: Aug. 24, 2022

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ISO-NE News

ISO-NE: Reliability Still Depends on Mass. LNG Import Terminal

By Sam Mintz

In a new *statement* released Monday, ISO-NE and many of its gas and electric distributors warned that the region's near-term grid reliability depends on its access to LNG — and that access to LNG in turn relies on a single facility outside Boston.

The message comes ahead of a summit next week that will bring FERC commissioners and staff to Vermont to discuss the tenuous state of the region's grid this winter and in the coming years.

The statement published by the RTO says that weaning New England off its dependence on imported LNG remains its long-term goal, as the region transitions to more renewable generation.

But in the short term, an LNG import facility operated by Constellation Energy in Everett, Mass., is vital to keeping the lights on, it says.

"The region must ensure the continued operation of the Everett LNG Facility to maintain reliable electric and natural gas service for New England consumers," ISO-NE and the distributors said.

Everett can store the equivalent of 3.4 Bcf of natural gas and has the equipment needed to import, store, transport and re-gasify LNG. It can deliver up to 435 MMcfd to two of the five pipelines used by generators and gas utilities in New England.

The fate of the Everett facility is tied to the attached Mystic Generating Station, which ISO-NE has paid to retain until its retirement in 2024.

In a separate *news release*, ISO-NE CEO Gordon van Welie called energy adequacy "under-appreciated, poorly understood, but vitally important."

"By raising awareness of this issue ahead of the upcoming forum, ISO New England and the region's utilities hope to begin the process of developing a strong, coordinated response with the New England states, NEPOOL and regional stakeholders to assure that energy adequacy is consciously addressed as the region charts a course toward a clean power system," van Welie said.

The utilities joining ISO-NE in issuing the statement were Avangrid, Eversource Energy, Liberty Utilities, National Grid, Rhode Island Energy and Vermont Electric Co.

Kickstarting Solutions

The aim of the forum next week is to start hashing out solutions to New England's unique but well documented challenges around gas supply. Aiming to kick off the conversation, ISO-NE put forward a few ideas in its statement Monday.

For one, the grid operator called on the region to "undertake a comprehensive study of both the energy adequacy problem and the potential solutions for addressing the problem."

ISO-NE shouldered its own responsibility and acknowledged that any changes to its tariff will have to go through NEPOOL and FERC, but it also called on the states to hold up their end of the bargain.

"The New England states have a major role in determining the nature and extent of any regional risk mitigation solution, since they represent the end consumers who will have to pay for the insurance, and further, control the siting and permitting of the necessary infrastructure," the statement says.

The RTO also put new weight behind the idea of an energy reserve, which was raised recently by the New England states in a request to the Biden administration. (See *New England Governors Ask Feds for Help with Winter Reliability*.)

"An energy reserve would cover unusual events, including combinations of major contingencies or extreme weather or both," ISO-NE said, likening it to regionwide insurance.

The grid operator said a reserve could come in a few different forms: state-regulated cost-of-service infrastructure investments coupled with contracting for the energy; FERC-regulated cost-of-service rates for recovering infrastructure investments and forward energy supply chain arrangements; or FERC-regulated wholesale electric market tariffs to incentivize investment.

| Shutterstock

"At this stage, given the region's experience over the past two decades, the region needs to determine how much insurance to buy and which options, or combinations of options, will be the most effective and efficient," the grid operator said.

All in the Same Room

The *forum* next week — an all-day affair in Burlington, Vt., on Thursday — will feature nearly 30 panelists from the states, FERC, ISO-NE, distribution and pipelines companies, and more.

According to FERC, it's intended to "achieve greater consensus or agreement among stakeholders in defining the electric and natural gas system challenges in New England and identify what, if any, steps are needed to better understand those challenges before identifying solutions."

ISO-NE and the states, in particular, have been lobbing barbs back and forth for years over who holds responsibility for solving the problems facing the region.

Even in the unlikely event of a breakthrough or consensus on Thursday, it's likely too late to make changes that could help steady the grid this winter: ISO-NE has already said it won't take steps to stockpile fuel, and that rolling blackouts could be on the horizon if the region sees an extended period of extreme cold. (See *ISO-NE Says No Extra Winter Programs Make Sense this Year*.) ■

Northeast news from our other channels

Maine, RI Join Multistate Hydrogen Agreement

NetZero Insider

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ISO-NE News

DC Circuit Weighs in on Outstanding Mystic Questions

By Sam Mintz

The D.C. Circuit Court of Appeals issued rulings last week on a variety of petitions relating to the Mystic Generating Station, granting review to a group of state regulators and rejecting several requests from the plant's owner (20-1343).

The D.C. Circuit Court of Appeals gave rulings on a number of outstanding questions involving the Mystic Generating Station. | *Shutterstock*

At issue were six FERC orders related to the approval of a cost-of-service agreement between Mystic and ISO-NE, dating from 2018 to 2020 (ER18-1639). (See *FERC Further Alters Mystic Cost-of-service Agreement*.)

First, Mystic argued that FERC mistakenly applied the "original cost test" to calculate the rate base for Units 8 and 9, which were kept operating by the agreement.

The original cost test says that a utility "may only earn a return on (and recovery of) the lesser of the net original cost of the plant or, when plant assets change hands in arms-length transactions, the purchase price of the plant."

Mystic's parent company valued Units 8 and 9 as part of a merger in 2012 around $925 million and claimed that "sale" price should determine its rate base.

The commission rejected that approach as inconsistent with the original cost test because of the units' full purchase history.

The D.C. Circuit sided with FERC on that question and did not grant review, saying the decision "accorded with [the commission's] precedent and was supported by reasoned explanation."

The court also dismissed Mystic's challenge to the capital structure adopted by the commission for ratemaking purposes, because a subsequent order made the challenge moot.

Another order examined in the court's ruling was related to the cost recovery for Everett, an LNG terminal attached to the plant. Both Mystic and state regulators challenged FERC's approach.

The regulators argued that the commission lacked jurisdiction to regulate the rates charged by Everett and that FERC's decision to allocate 91% of Everett's operating costs to Mystic — and therefore ultimately to ratepayers — was arbitrary and capricious.

The court agreed with those arguments but not with Mystic, which argued that "the commission erred in excluding Everett's purchase price from Everett's rate base."

Next, both Mystic and the states challenged the "true up" mechanism approved by FERC, designed to allow parties to "reconcile cost projections with actual expenditures via surcharges and refunds as necessary." Mystic argued that "the true-up mechanism will lead to relitigation of its historic costs."

The court said that was unfounded. It accepted, however, the states' arguments that FERC failed to address a request for clarification about how it calculated revenue credits and Everett's tank congestion charges. Those issues were remanded by the court for clarification.

Finally, the states took issue with parts of a "clawback" provision that would require Mystic to reimburse ratepayers for some expenses if it re-enters the New England energy markets after the agreement is over.

The states argued that Everett's costs shouldn't have been excluded from the clawback rules, and the court agreed. It also granted review of the states' claim that FERC "failed to address their argument that the Mystic agreement will induce Mystic to delay capital projects into the term of the agreement." ■

ISO-NE News

FERC Approves Changes to ISO-NE DER Interconnection Process

FERC last week accepted ISO-NE's proposed changes to its process for interconnecting distributed energy resources, finding them just and reasonable with some clarifications (*ER22-2226*).

Previously, some DERs had used the ISO-NE interconnection process, while others used state interconnection processes, a disconnect that the grid operator said "results in multiple coordination problems and inefficiencies that in some cases result in adverse outcomes for DER developers."

ISO-NE proposed that all new DERs proceed through the applicable state processes to ease the uncertainty. (See *ISO-NE Sends New DER Interconnection Proposal to FERC*.)

In an order on Friday, FERC agreed that the change makes sense.

"We find that ISO-NE's proposal to exclude DERs from its interconnection procedures is just and reasonable because it would promote certainty in ISO-NE's interconnection process and reduce a significant burden on ISO-NE," the commission wrote.

FERC also clarified that "the commission's jurisdiction over wholesale sales from DERs and their participation in the wholesale markets are not impacted by the change."

The Solar Energy Industries Association, Advanced Energy Economy and ENGIE North America had all backed the changes, saying they would help resolve unique concerns in New England because of the growth of DERs in the region.

After FERC's approval, the tariff changes went into effect Sunday.

ISO-NE's proposal concerned individual DERs; as such, it is separate from its compliance with FERC Order 2222, which deals with DER aggregations. In concluding its order, the commission noted that, as it had in Order 2222, it "may revisit this independent entity variation in the future should [it] discover abuses of the distribution interconnection process or the rise of unnecessary barriers to the participation of distributed energy resources in RTO/ISO markets." ■

— Sam Mintz

FERC approved changes to the ISO-NE interconnection process for DERs. | *Shutterstock*

ISO-NE News

FERC Fines CPower $2.5M over ISO-NE Capacity Payments

By Sam Mintz

Demand response aggregator CPower has agreed to pay a $2.5 million penalty after FERC's enforcement division found the company took capacity payments in violation of ISO-NE rules (*IN22-7*).

The violations stemmed from the use of ISO-NE's Price Responsive Demand (PRD) structure, implemented in the Forward Capacity Market in 2018.

Under PRD, an active demand capacity resource (ADCR), made up of one or more demand response resources (DRRs), can obtain a capacity supply obligation (CSO) and receive capacity payments.

Importantly, they're then also required to submit demand response offers from the associated resources into the region's day-ahead and real-time markets at levels equal to or greater than their CSO.

Between 2018 and 2019, CPower failed to do so, FERC found.

"The deficiencies between CPower's CSOs and DROs [demand reduction offers] … grew from a minimum of 5.5 MW in June 2018 to a minimum of 33.2 MW in February 2019," the enforcement filing says.

The company earned nearly $2.5 million in capacity payments that did not have associated DROs, FERC found. And an "individual within substantial authority personnel at CPower" was aware that some of its resources were offering at levels less than their capacity obligations, FERC said.

Residential solar panels can be used as distributed energy resources. | *Shutterstock*

FERC's Office of Enforcement started looking into the discrepancy after a referral from the ISO-NE Independent Market Monitor, according to the agency.

In response to the IMM's initial inquiry, CPower attributed some of the differences to new demand response assets that "did not materialize."

But FERC found that CPower had violated the ISO-NE tariff, and the company agreed to pay a civil penalty of $2.54 million and disgorge $2.46 million in earnings.

According to the FERC filing, CPower has hired a senior director of regulatory and government affairs and a senior vice president of regulatory affairs in the last year to improve its compliance program.

CPower confirmed with *RTO Insider* that it settled with FERC, saying, "While today's outcome stems from the interpretation of what was at that time a new tariff for which there was no precedent, we appreciate that FERC has confirmed that there was no intentional violation and acknowledged the strength of CPower's compliance program." ■

MISO News

MISO, SPP Propose 90-10 Cost Split for JTIQ Projects

By Amanda Durish Cook

MISO and SPP last week laid out a percentage-based cost allocation for their $1 billion Joint Targeted Interconnection Queue (JTIQ) transmission study that will assign most costs to interconnecting generation.

The grid operators plan to assign 90% of project costs to interconnection customers and 10% to an aggregate of MISO and SPP load. The RTOs said they will allocate a fixed, per-megawatt charge to interconnection customers that have a 5% or greater impact on a facility in the neighboring region to pay for the portfolio.

"We think a 90-10 split would work well for this portfolio and for future portfolios," MISO's Andy Witmeier told stakeholders during a JTIQ study teleconference Aug. 22.

National Grid Renewable's Rafik Halim said he thought a 50-50 allocation between load and new generation would be more suitable. He asked for a rationale behind the cost split.

"If MISO and SPP believe a 90%-10% split is appropriate, we need to see why. This is a billion dollars of investment," he said.

Halim also asked for an analysis to show how the grid operators arrived at the 5% impact threshold for new generators.

American Clean Power Association's Daniel Hall seconded the ask for the 90-10 cost allocation's justification.

The RTOs staff remained steadfast in asserting that the JTIQ's main purpose is to enable new generation, making it only fair that interconnection customers bear the brunt of the costs. They also said the 5% impact factor is a well established approach that both grid operators currently use.

Other stakeholders asked whether the RTOs plan to create protections that ensure transmission facilities get built should generation developers balk at network upgrade costs and withdraw from the queue. How would the portfolio remain funded, they asked.

SPP's Neil Robertson said staff's plan is to assign a fixed, one-time upfront charge to eliminate unexpected sticker shock and cut down on the number of queue dropouts. He said the process will ensure the upgrades' expense is spread evenly across generation and that no project is encumbered with an eye-popping upgrade bill.

David Kelley, SPP's director of seams and market design, said the RTOs are confident that enough generation developers will continue to construct projects near the seams and fund JTIQ projects.

The study's portfolio was initially priced at $1.65 billion. However, it contained two project duplicates with MISO's recently approved $10.3 billion long-range transmission portfolio. Staff said SPP's benefits from the projects were negligible and independently pursued the duplicates under its regional process, reducing the JTIQ to about a billion-dollar investment. (See *MISO, SPP Finalize JTIQ Results with MISO Tx Duplicates*.)

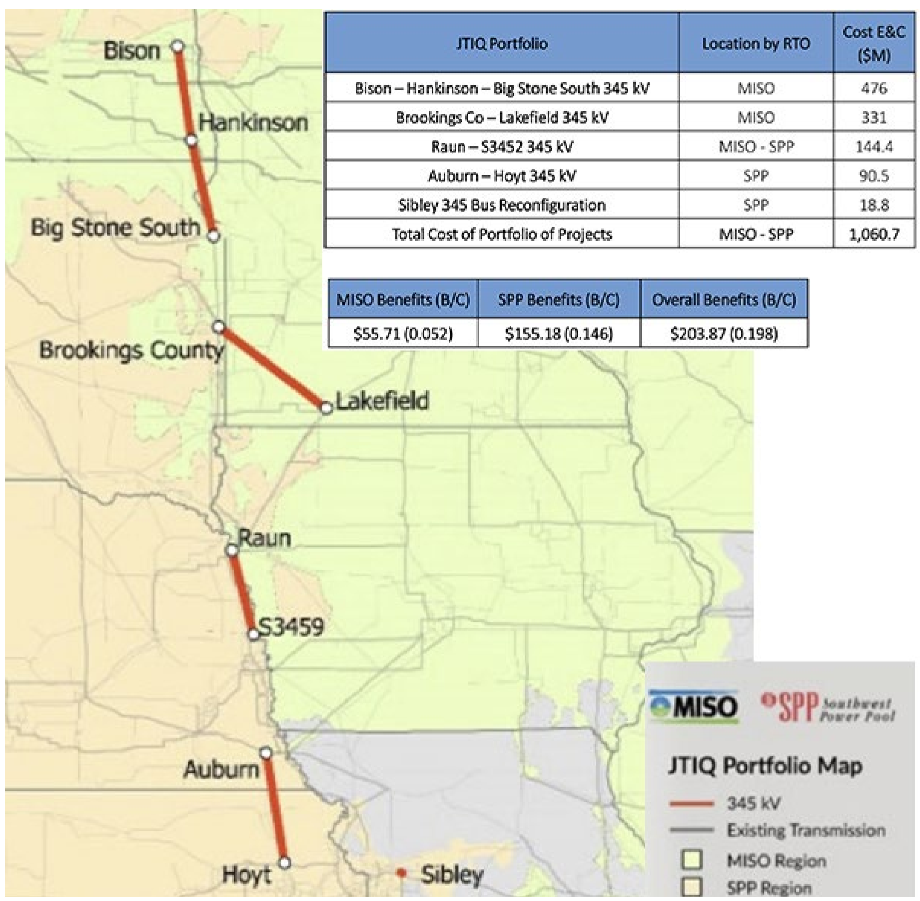
The current JTIQ portfolio includes:

- the $476 million Bison-Hankinson-Big Stone South 345-kV line located in MISO's footprint that touches both Dakotas and Minnesota;
- the $331 million Brookings Co-Lakefield 345-kV line from South Dakota into Minnesota in MISO territory;
- the $144.4 million Raun-S3452 345-kV line on the Iowa-Nebraska border, straddling both MISO and SPP;
- the $90.5 million Auburn-Hoyt 345-kV line from Nebraska into Kansas in SPP's region; and
- the nearly $19 million Sibley 345-kV bus reconfiguration in SPP's portion of northwest Missouri.

The RTOs announced in late June that they plan to ditch their current affected systems study process for more interregional transmission studies like the JTIQ study. (See *MISO, SPP Commit to Replacing Affected System Studies*.)

Robertson said the portfolio began as a "one-off" process and has since evolved into an "enduring, repeatable" design.

The grid operators plan to hold another meeting Sept. 30 to finalize cost-allocation details. Kelley asked stakeholders to send their improvement suggestions for the concept to the RTOs. ■



JTIQ Portfolio	Location by RTO	Cost E&C ($M)
Bison – Hankinson – Big Stone South 345 kV	MISO	476
Brookings Co – Lakefield 345 kV	MISO	331
Raun – S3452 345 kV	MISO - SPP	144.4
Auburn – Hoyt 345 kV	SPP	90.5
Sibley 345 Bus Reconfiguration	SPP	18.8
Total Cost of Portfolio of Projects	MISO - SPP	1,060.7

MISO Benefits (B/C)	SPP Benefits (B/C)	Overall Benefits (B/C)
$55.71 (0.052)	$155.18 (0.146)	$203.87 (0.198)

Details of MISO and SPP's JTIQ portfolio | *MISO and SPP*

MISO News

MISO, SPP Regulators Finish Pancaking Strawman

Working Group Inventories Rate Issues on RTOs' Seams

By Tom Kleckner

| © RTO Insider LLC

A working group of MISO and SPP state regulators addressing rate pancaking issues agreed last week that their work is finished and ready to be turned in to the Seams Liaison Committee (SLC).

Marcus Hawkins, executive director of the Organization of MISO States, said during a virtual meeting Aug. 22 that the Rate Pancaking Working Group's (RPWG) strawman has been tweaked since its initial draft. It includes four recommendations for the SLC's consideration, or "next steps ... you all could consider to further this work," he said.

The working group identified the treatment of unreserved use charges for transmission configuration changes and emergency ties on the seam as its key issue. It suggested the SLC request both RTOs develop comparable treatment of unreserved use with criteria that is simple, fair and easy to administer, and to also comparably treat the billing of firm network reservations.

The RPWG also looked at the inability of market participants to obtain congestion hedges for firm transmission procurement. The group suggested the RTOs explain to regulators how firm transmission reservations should be obtained and the issues that prevent awarding hedges for firm service customers. The RPWG proposed asking stakeholders to share their experiences with procuring financial transmission rights and whether it affected resource procurement, and to monitor SPP's work on counterflow optimization.

The grid operator has scheduled a virtual *workshop* for today to discuss adding counterflow optimization to its market mechanism that hedges load against congestion charges. SPP and its stakeholders have been unable to reach consensus on the initiative, which began in 2019. The RTO still hopes to bring a solution to the October board meeting. (See "Counterflow Optimization not Dead Yet," *SPP Board of Directors/Markets Committee Briefs: April 26, 2022*.)

The RPWG's other findings and recommendations included:

- investigate how rate pancaking can be eliminated or reduced for long-term contracts, beginning with consideration during the Nov. 9 Common Seams Initiative joint stakeholder meeting of a long-term interregional rate that can reduce pancaking costs and increase revenue generated. The group suggested hearing from SPP on its rate-pancaking initiative and from MISO on whether it has any strategic actions related to the seams, and to request the RTOs assess different ways to adjust rates on the seams and increases transmission service sales.
- determine how interregional projects can cause unintended pancaking issues. The group advocated that during the next SLC meeting, the grid operators describe how the projects could change flows on the system and corresponding charges for load that didn't exist before.

The SLC formed the RPWG to inventory rate pancaking along the grid operators' seams. The group surveyed staff and stakeholders in developing their recommendations. ■

Entergy Rebuts Criticism of its Transmission Planning

By Amanda Durish Cook

Entergy last week responded to criticism filed at FERC that the utility is purposefully undermining transmission planning in MISO South.

In a statement to *RTO Insider*, Entergy countered Southern Renewable Energy Association's (SREA) claim that the company is deferring and hindering the region's transmission planning by saying it "strongly supports" investment in transmission, but that it must pay attention to costs.

The company said that since joining MISO in late 2013, it has invested $6 billion in new transmission infrastructure, resulting in nearly 600 miles of new lines. Entergy said that level of investment is above the industry average.

"Entergy strongly believes that new transmission will play an important role in MISO South as we integrate additional solar resources and evolve our generation portfolio to be more sustainable," it said. "We recognize that creating a carbon-free future calls for more investments in renewable energy."

Commenting in FERC's Notice of Proposed Rulemaking on transmission planning, SREA accused Entergy of habitually proposing new generation plants just in time to thwart MISO transmission recommendations, thus harming reliability in MISO South. (See *SREA Criticizes Lack of MISO South Planning in FERC Tx Proceeding*.)

Entergy said it's working with its regulators and stakeholders to "responsibly expand access to renewable energy … under a framework that balances reliability, affordability and environmental stewardship."

Entergy line work in southwest Louisiana in 2020 after Hurricane Laura | *Entergy*

The company said MISO's planning decisions have "major cost implications to our customers, nearly 30% of whom live in poverty and already struggle to pay their monthly bills." It said the $30 billion to $100 billion of transmission investment that MISO expects with its long-range transmission plan's (LRTP) four portfolios will invariably raise costs for its ratepayers.

The grid operator approved its first LRTP portfolio in late July. The $10.3 billion transmission investment in 18 projects is aimed at MISO Midwest only. It will be several years before their planners seek projects in MISO South. (See *MISO Board Approves $10B in Long-range Tx Projects*.)

"Even at the low end of that range, Entergy's customers would be responsible for hundreds of millions of dollars per year in transmission costs. When we express our views, along with numerous other utilities and stakeholders, we do so based on what we believe is in our customers' best interests — just as every other stakeholder does in MISO's process," Entergy said.

The utility pointed out that MISO ultimately decides which transmission projects to place before MISO's Board of Directors for its approval.

Entergy also addressed the more potent storms that have formed in the Gulf of Mexico in recent years and their impact on its existing transmission infrastructure.

"Ultimately, Entergy and other utilities have to answer to our customers and our state regulators for the reliability and cost of the essential service we provide," it said. "In a world where climate change is happening and we are experiencing more severe weather events and other challenges, there are important policy decisions to be made about what investment is needed to better prepare electric systems and other infrastructure to withstand those events."

Entergy said it welcomes "a reasoned and fact-based discussion with our regulators and stakeholders about what that investment should look like and how to fund it, without imposing burdensome additional costs on our customers." ■

MISO News

MISO Flags Capacity Gap Risks in Fleet Transition Assessment

Stakeholders Propose Midyear Capacity Accreditation

By Amanda Durish Cook

CARMEL, Ind. — MISO last week said its future holds exponential renewable growth, free-falling carbon emissions and a stubbornly persistent capacity risk, requiring a slew of new capacity.

The pronouncements come from the initial *findings* of MISO's annual Regional Resource Assessment (RRA). The grid operator said that by using publicly available utility plans and its own assumptions, it expects the system will draw 30% of its annual energy from renewables by 2027 and approach 60% by 2041.

Also by 2041, the footprint will collectively decarbonize 80% from peak 2005 levels, MISO predicted. Renewables currently make up about 13% of the RTO's resource portfolio.

"That is significant because this study is basically bringing together our members' plans … and showing what the footprint will look like," MISO engineer Aditya Jayam Prabhakar said during a Resource Adequacy Subcommittee meeting Wednesday.

Jayam Prabhakar said the risk of a capacity shortfall will persist throughout the fleet transition, "highlighting the immediate importance of coordinated resource planning."

The grid operator said it found a need for members to expand nameplate capacity by 100 GW by 2030 to meet their combined carbon-reduction plans and stay within safe reserve margins. By 2041, MISO may need a 200-GW expansion in nameplate capacity.

The RTO also said it expects average capacity factors for operational natural gas and coal units to decline between 10 and 30% over the next 20 years. It said that even if current company resource planning is implemented on time, a systemwide shortfall is possible beginning in 2027.

Jayam Prabhakar added that the assessment relies on "highly evolving" information and characterized MISO's analysis as a "guided tour," as opposed to a deep exploration of future possibilities.

MISO did not include generation retirements beyond what is already publicly announced. Michelle Bloodworth, of coal lobby group America's Power, said she thought the RTO was underestimating thermal generation retirements.

"Like all studies, the results of the RRA are sensitive to inputs and assumptions. This is but one possible scenario in a quickly evolving landscape," Policy Studies Engineer Hilary Brown said.

She said MISO is notably missing some intermediate resource planning information

| *Entergy*

MISO News

from members around their 2030 greenhouse gas emissions goals. "Many companies have defined carbon-reduction milestones around 2030, leading to a possible large, single-year buildout."

Responding to stakeholders' questions, Brown said MISO has not yet included the torrent of renewable energy development that will possibly take place under the recently signed Inflation Reduction Act. She said the impacts under the law will be contemplated in next year's assessment.

"We're going to see some pretty crazy changes next year in how companies react to the Inflation Reduction Act," Southern Renewable Energy Association Executive Director Simon Mahan said.

Brown said a "one-for-one capacity replacement" is not sufficient when replacing thermal generation with intermittents. She said that while MISO foresees a deepening capacity shortfall, members' plans could change in reaction to MISO's Planning Resource Auctions (PRAs).

"This isn't new. We've seen it in last year's PRA," Brown said of declining and inadequate margins. (See *OMS RA Summit Confronts Midwestern Supply Squeeze*.)

Months after MISO's capacity auction shortfall, several utilities unveiled deferrals on coal retirements.

WEC Energy Group and Alliant Energy have announced they are postponing retirement plans for multiple coal plants because of concerns over grid reliability. Likewise, Ameren Missouri is expected to defer the planned Sept. 1 retirement of its 1.2-GW Rush Island power plant until 2025. Two Montana Public Service Commissioners recently called on state lawmakers to do everything in their power to keep the Colstrip generating facility operating to prevent freezing deaths this winter. Colstrip is owned by Talen Montana, Puget Sound Energy, Portland General Electric, Avista, PacifiCorp and NorthWestern Energy.

On the other end of the spectrum, Clean Grid Alliance in mid-August saluted Illinois, Iowa and Indiana in particular as jurisdictions in the MISO footprint where renewable energy development is blossoming.

The alliance said Indiana's 6.3 GW of solar projects in development currently ranks third in the nation; Illinois' nearly 8 GW of operating wind, solar and storage capacity currently ranks sixth; and Iowa leads with 207 MW of land-based wind power coming online in the second quarter of 2022.

CGA said the nine states in MISO's Midwestern region combined have 12 GW of clean power capacity in advanced stages of development.

Multiple stakeholders said MISO did not reveal enough about its modeling methods and data sources for others to fact-check its resource analysis.

The RTO plans to publish the full 2022 RRA in November.

Stakeholders Ask MISO for Midyear Capacity Accreditation

Disappearing reserves in its capacity auction has sparked a new stakeholder proposal at MISO.

MidAmerican Energy's Dennis Kimm asked that MISO accredit new planning resources that enter the picture after the planning year is underway.

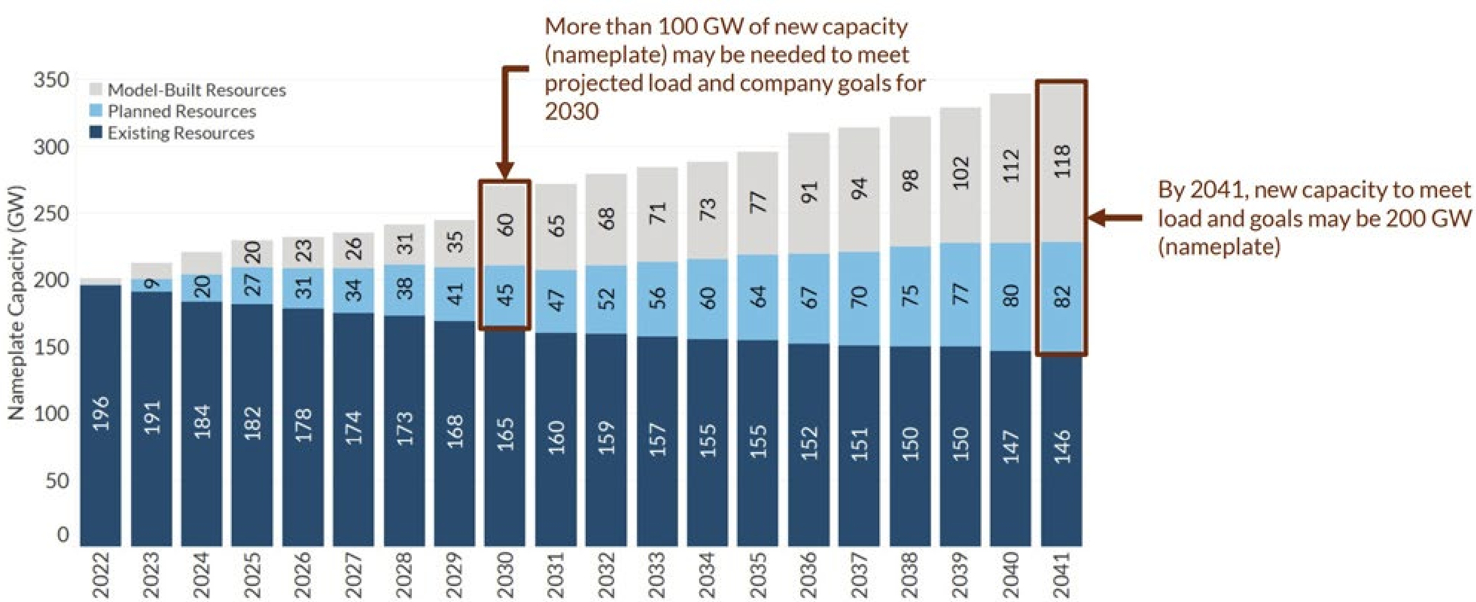
MISO doesn't currently permit new generation to convert its output into accredited capacity in the middle of a planning year. New generators currently must wait until preparation for next year's capacity auction begins before they become eligible to receive zonal resource credits.

Several stakeholders said they supported the proposal and requested MISO create new tariff language immediately.

Alliant's James Niccolls said that, "frankly, it's hard to explain" MISO's current practice to his company's leadership and customers.

"There's obviously widespread stakeholder support on this," RASC Chair Kari Hassler said.

Meanwhile, stakeholders again requested that MISO publish more data ahead of its PRAs on generator suspensions and granted participation exclusions. Some have said MISO should publish a line item on generation that's likely to be unavailable in the auction and give members a better idea of the footprint's expected margins before the auction window opens. ■



MISO future capacity need projections | *MISO*

NYISO Proposes $32M Project Budget for 2023

Compensation Study Results in Salary Boost for 300 Staffers

By John Norris

NYISO is proposing a $32 million project budget for 2023, a $5 million reduction from this year's spending.

NYISO's Brian Hurysz, who *presented* the final project recommendations for the 2023 budget to the Budget and Priorities Working Group (BPWG), said 13 of the 24 projects that had been identified as stakeholder priorities were included in the spending plan.

The $31.98 million budget includes $13.7 million for labor, $9.7 million for capital and $8.5 million for professional services, $5.2 million lower than the 2022 project budget of $37.2 million. The 2022 budget increased project spending by $10.7 million over 2021 largely because of the Alternate Control Room Renovation project, which was deferred from 2021, and the Distributed Energy Resource Integration project.

The market and enterprise budget recommendations were $11.36 million and $20.62 million, respectively.

In addition to deferring 11 of the 24 proposed market projects, including the duct firing modeling that NYISO desired, the ISO is recommending cost savings or scope changes for some projects:

- The Distributed Energy Resources (DER) Participation Model will be delayed, with deployment planned later in 2023. The cost of the project has increased, and the operational enhancements have been reduced.
- Storage as Transmission, requested by stakeholders, will be limited to "issue discovery" — education sessions and identification of potential solutions for future ranking — in 2023.
- Capacity Resource Interconnection Service (CRIS) Expiration Evaluation & CRIS Tracking: CRIS Tracking will be deferred to 2024; CRIS Expiration Evaluation will develop CRIS Tracking requirement updates and be implemented with CRIS Tracking in 2024.
- FERC Order 2222 Compliance: Scope of the project has increased based on updated information from FERC. The ISO recommends changing commitment from completed documentation of Functional Requirements (FRS) to Market Design Concept Proposed (MDCP).
- Balancing Intermittency & Dispatchability and Fast Response Product: The ISO proposes combining some of the Dispatchability and Fast Response scope with the Balancing Intermittency, which was recommended in Potomac Analytics' State of the Market (SOM) project.
- Unified Communications Platform: The ISO recommends deferring the work until 2024, saying the equipment to be replaced is not end-of-life in 2023.

NYISO said stakeholder feedback on the budget can be *emailed* to Hurysz.

The ISO's full 2023 draft budget will be presented at the Sept. 15 BPWG meeting and the Sept. 28 Management Committee meeting.

Compensation Benchmarking Study Boosts Pay for 300 ISO Staffers

NYISO will spend $2.5 million in 2022 to raise the salaries of about 300 non-executive employees in response to a benchmarking study commissioned to address increasing attrition.

NYISO Chief Financial Officer Cheryl Hussey | *NYISO*

NYISO Chief Financial Officer Cheryl Hussey *said* the ISO hired consulting firm Mercer to conduct the study after seeing an increase in attrition and the number of people rejecting the ISO's job offers.

Mercer reviewed compensation data on 525 employees in 247 job titles and found that certain positions — including entry-level grid operators, engineers, software developers, IT security and infrastructure analysts and technical specialists — "trended significantly below the market," Hussey said.

The ISO agreed to spend $2.5 million to raise "about 300" such employees to the mid-point of their peer group, retroactive to July 1, she said. The cost of the adjustments will be about $5 million for 2023.

				Estimated Cost (in millions)			
Project	Project Type	2023 Proposed Deliverable	2022 Deliverable	Labor	Capital	Prof. Serv.	Total
~~5 Minute Transaction Scheduling~~	~~Prioritize~~	~~Market Design Concept Proposed~~		~~0.07~~	~~0.00~~	~~0.74~~	~~0.81~~
~~Advancing NYISO Transparency - Requested by DC Energy~~	~~Prioritize~~	~~Deployment~~		~~0.09~~	~~0.00~~	~~0.40~~	~~0.49~~
Balancing Intermittency (SOM)	Prioritize	Market Design Concept Proposed		0.12	0.00	0.15	0.27
Constraint Specific Transmission Shortage Pricing (SOM)	Prioritize	Deployment	Functional Requirements	0.38	0.00	0.50	0.88
Coordinated Grid Planning Process (CGPP) Support - Requested by New York TOs	Prioritize	Issue Discovery		0.07	0.00	0.00	0.07
CRIS Expiration Evaluation	Prioritize	Functional Requirements	Market Design Complete	0.11	0.00	0.00	0.11
~~Dispatchability and Fast Response Product - Requested by NYPA~~	~~Prioritize~~	~~Market Design Concept Proposed~~		~~0.07~~	~~0.00~~	~~0.00~~	~~0.07~~

NYISO is recommending deferring 11 of the 24 proposed market projects for 2023 and cost savings or scope changes for others. | *NYISO*

NYISO News

The ISO will use nearly half of its $10.7 million 2021 budget surplus to fund these raises and a prior 3% raise given to non-executive staff retroactive to Jan. 1.

Hussey said the ISO would continue monitoring market trends and adjust salary levels again if warranted. "More recently we have had more success in our recruiting. Our vacancy rate is down. But it's really soon to show a significant change resulting from the latest salary adjustments," she said.

Barring additional compensation adjustments, the remaining $5.7 million from 2021's budget surplus would be used to pay down the principal on outstanding debt, which is expected to total $82.5 million at the end of 2022.

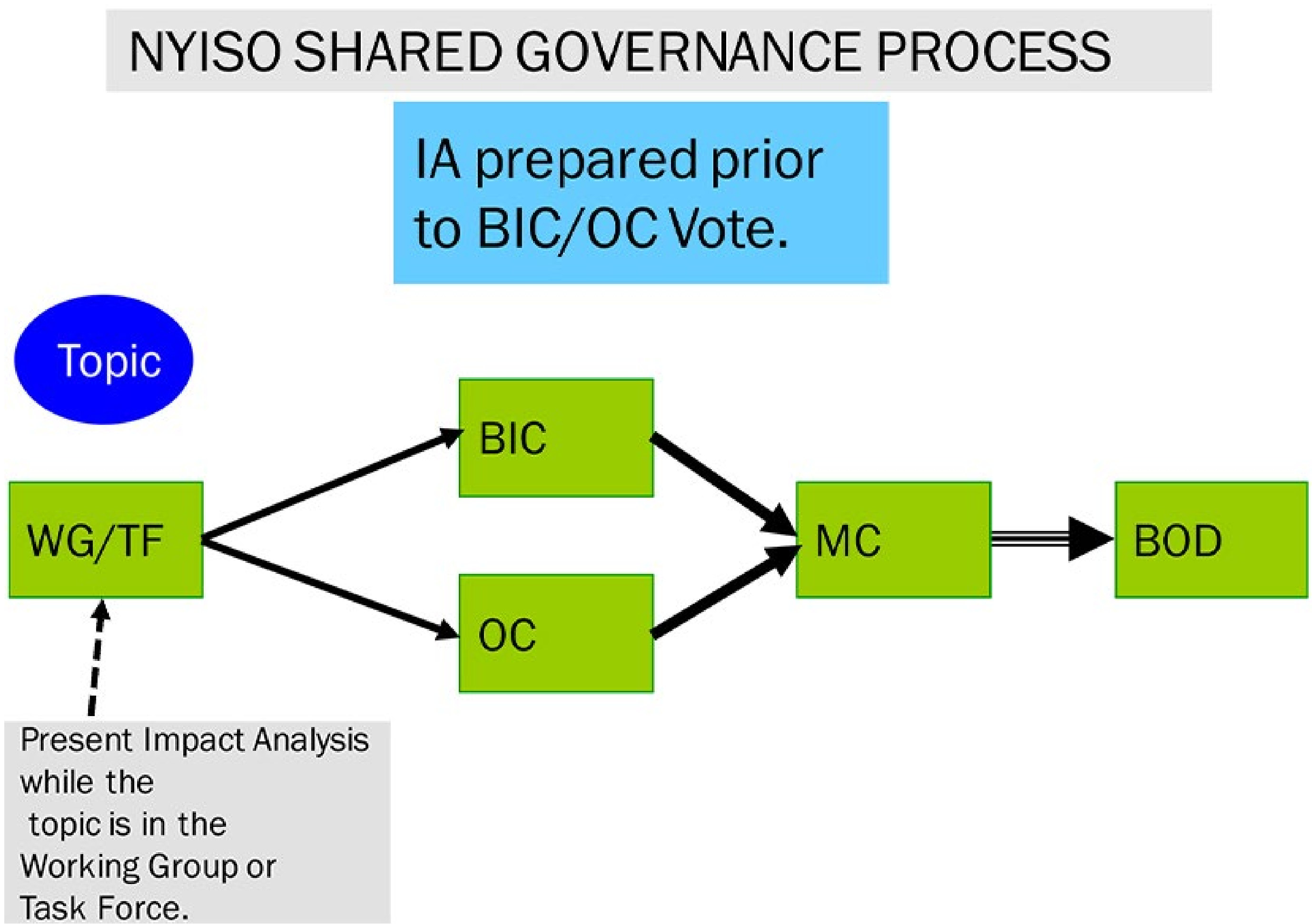
Four Projects in 2023 Budget from Consumer Impacts Analysis

The ISO's Tariq Niazi said that the ISO is *recommending* four projects be included in the 2023 budget based on its consumer impact analysis:

- Balancing Intermittency (SOM): The project will examine existing ISO market structures and rules to help identify changes needed to maintain system reliability, while addressing the state's climate goals cost effectively.
- Locational Capacity Requirements (LCR) Optimizer Enhancements: Will seek improvements to the LCR methodology to improve stability and transparency.
- Long Mountain PAR Operating Protocol: The ISO will develop an operating protocol with ISO-NE for the phase angle regulator (PAR) planned for the Long Mountain-Cricket Valley 345-kV intertie, an upgrade from the AC Public Policy Segment B project.
- Modeling Improvements for Capacity Accreditation (SOM): Continues the work of the Improving Capacity Accreditation project to allow consideration of reliability risks such as correlated fuel unavailability and long start up notifications not modeled by the current resource adequacy analysis software.

The ISO looks for projects that are anticipated to have a net production cost impact of $5 million or more per year; have an impact of more than $50 million per year on consumer energy or capacity market prices; incorporate new technologies into ISO markets for the first time; support a new type or category of market product; or create a mechanism for out-of-market payments for reliability.

Stakeholders expressed skepticism about the ISO's proposal to improve the modeling used by the resource adequacy analysis software GE MARS. Stakeholders said this proposal "missed the mark" since GE MARS represented such a small amount of the total resources used by NYISO. In response, Niazi stated that he would take these concerns back to his team to reevaluate. But he stressed that having accurate accreditation calculations was critical to reducing costs and improving reliability. ■



Consumer impact analysis process | *NYISO*

No Consensus on PJM Capacity Parameters

By Rich Heidorn Jr.

VALLEY FORGE, Pa. — PJM members failed to find consensus on any of four proposed sets of capacity auction parameters Wednesday, with the RTO's proposal winning support from slightly more than half of members but falling below the necessary two-thirds threshold.

Proposals by the Independent Market Monitor, Calpine and GT Power Group in the 2022 Quadrennial Review all received less than 50% support in the sector-weighted votes. (See "2022 Quadrennial Review," *PJM MRC/MC Briefs: July 27, 2022*.)

The parameters include the shape of the variable resource requirement (VRR) curve, the cost of new entry (CONE) for each locational deliverability area, and the methodology for determining the net energy and ancillary services (E&AS) revenue offset.

PJM's proposal *received* a sector-weighted vote of 52%, with support of most Transmission Owners, Electric Distributors and End-Use Customers, but little support from Other Suppliers or Generation Owners. GT Power's proposal on behalf of Cogentrix was the second favorite, winning 41%, with most support from the GO and OS sectors. The Monitor and Calpine packages trailed with 22% support each. Only 16% favored retaining the status quo parameters without changes.

Immediately after the meeting, the Members Committee approved a motion to forward the results of the MRC vote to the Board of Managers. The board is expected to file changes with FERC by Oct. 1; the changes would be effective with the July 2023 capacity auction.

Packages Explained

While PJM's proposal includes major maintenance in variable operations and maintenance for recovery in the energy market, the Monitor's would provide for recovery through the capacity market.

Both Calpine's and GT Power's proposals would continue to use historic net E&AS offsets, rather than switching to forward-looking

PJM Package A	**Independent Market Monitor** Package B	**Calpine** Package C	**Cogentrix/ GT Power Group** Package D
• Price cap increase at Point A • Slight shit to the left for quantities at Points A&B with greater left shift at point C ("foot" of the curve)	Left shift of quantities half-way between Package A and vertical curve	• Same price cap increase at point A as Package A • Same quantity as Package A while maintaining status quo for points B&C	Same curve as Package A but with a CT as the reference resource

Comparison of variable resource requirement (VRR) curves under proposals by PJM, the Independent Market Monitor, Calpine and Cogentrix/GT Power Group | *PJM*

PJM News

as proposed by PJM and the Monitor.

GT Power's would also continue to use a combustion turbine rather than a combined cycle plant as the reference unit because of the latter's greater dependence on volatile E&AS revenues. All other packages would switch to the combined cycle plant.

CEJA Impact

Before the vote, economist Paul Sotkiewicz, representing generator J-Power USA, said the rules for the ComEd zone should reflect the shortened lifespan for new fossil-fired generation as a result of the Illinois Climate and Equitable Jobs Act (CEJA), which requires the state to move to a 100% carbon-free power sector by 2045.

Sotkiewicz said the gross CONE will need to be updated to reflect the shortened economic life of new fossil units, noting a gas plant that went into service in 2026 would have only a 19-year lifespan rather than the 20-year assumption. "You can look at the [Illinois] legislation," he said. "It's clear as day."

PJM's Melissa Pilong said RTO staff had determined that no change in the lifespan was currently required.

Although PJM's tariff mandates consideration of the parameters every four years, "nothing prevents us from changing parameters between Quadrennial Reviews," MRC Chair Stu Bresler said.

DC Circuit Ruling

Sotkiewicz said PJM's position ignored the D.C. Circuit Court of Appeals' Aug. 9 ruling setting aside FERC's order in April that rejected NYISO's use of a 17-year assumed lifespan for a peaking plant in its capacity parameters (*21-1166*).

NYISO had cited the New York Climate Leadership and Community Protection Act (CLCPA), which mandates that by 2040, "the statewide electrical demand system will be zero emissions." The ISO concluded that a gas-fired plant built between 2021 and 2025 would have an average lifespan of 17 years because the CLCPA "requires electricity demand in New York to be served by 100% zero-emission resources" by 2040.

FERC rejected NYISO's proposed amortization period and required it to return to 20 years, noting that the CLCPA allowed the state's Public Service Commission to relax the emissions rules if needed to maintain reliability (*ER21-502-001*). FERC said the ISO's proposal was "premised on the speculative assumption that all fossil-fueled resources will cease operation in 2040."

The D.C. Circuit granted the appeal of the Independent Power Producers of New York's (IPPNY), noting that FERC's review of Federal Power Act Section 205 filings is limited to whether the proposed rates are reasonable and not whether the proposal is more or less reasonable than alternative designs. The court said FERC's decision to reject NYISO's filing based on the possibility that the PSC might alter the CLCPA's requirements was "squarely inconsistent with its precedents."

FERC can abandon its precedents as long as it provides reasoned explanation for its action and acknowledges that it is changing its position, the court said. "FERC's order neither recognized nor explained its departure from precedent," it said. "That was arbitrary."

The Sierra Club's Casey Roberts said the D.C. Circuit ruling was unpublished and lacked much detail. "I don't think it requires upending the Quadrennial Review," she said.

Melissa Pilong, PJM | © *RTO Insider LLC*

Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), said the review "has been a great process," although he said "most advocates still have a concern about over-procurement. It's something that costs consumers billions." He said most advocates would support the Monitor's proposal.

Susan Bruce, of the PJM Industrial Customer Coalition, said the ICC supported both the PJM and IMM proposals. The loss-of-load expectation (LOLE) was "much higher" for the other proposals, she said. The others also produce results far beyond the one-day-in-10-years LOLE reliability standard, increasing customers costs.

Roberts said the most recent capacity auction procured 13 GW in excess of the RTO's reliability requirement. ■

PJM Markets and Reliability Committee Briefs

Discussions Continue on Market Seller Offer Cap

VALLEY FORGE, Pa. — Load interests continued to oppose PJM's *proposal* to change the market seller offer cap (MSOC), a month after it failed to meet the two-thirds endorsement threshold at the July 27 Markets and Reliability Committee meeting.

The proposal, which would ensure sellers are always able to represent the cost of their Capacity Performance (CP) risk when offering into the Base Residual Auction, had won only 60.4% support, as load sector stakeholders expressed concern over its impact on capacity prices. (See *Change to PJM Market Seller Offer Cap Falls Short*.)

The rule change would set the MSOC at the greater of the CP quantifiable risk (CPQR) or net avoidable-cost rate (ACR) inclusive of CPQR. PJM said it would address circumstances in which a unit with a positive CPQR value has that cost offset by an otherwise negative net ACR, which could result in a $0 offer cap. PJM had hoped to win stakeholder and FERC approval for the change effective with the 2024/25 capacity auction in December.

Load interests remained cool to the idea at the MRC on Wednesday.

Gregory Carmean, executive director of the Organization of PJM States Inc. (OPSI), asked PJM's Pat Bruno why it was in buyers' interests to "pay upfront the default costs of a supplier."

"We think it's in consumers' interests to achieve competitive outcomes in the auction results," Bruno responded. That result, he said, is "clearing the cheapest set of resources including the risk of nonperformance."

Susan Bruce, representing the PJM Industrial Customers Coalition, suggested more work was needed before considering the proposal. "Are we ready for prime time with this vote?" she asked.

Independent Market Monitor Joe Bowring said PJM's proposal would displace the Monitor's role in setting the offer cap and fails to adequately define CPQR.

"We do not agree that what's being proposed is a competitive outcome, or that it's a narrow change," he said. "You simply can't have an unlimited adder that's not defined in the tariff."

Bowring said not using net energy revenues as an offset to CPQR breaks the "essential link" between the energy market and the capacity market, which generally means lower capacity prices when energy market prices are high. Because PJM has not defined how it would calculate the CPQR or the asserted opportunity cost, the RTO cannot say that the impact would be small, Bowring said.

Carl Johnson, representing the PJM Public Power Coalition, said his members agree with Bruce's and Bowring's concerns.

"I've become convinced we cannot have this discussion separate from the holistic" discussions at the Resource Adequacy Senior Task Force, he said. The proposal "is such an open door to market power that I don't see how PJM could effectively mitigate it."

However, Johnson said his members "do want to represent CPQR in their offers, so they wouldn't go as far as [Bowring] recommended."

Jason Barker of Constellation Energy said PJM's proposal is "consistent with real-world economic decisions" that generation owners are making.

"PJM's proposal is welcome; it's ready; and it solves a very distinct problem that sellers encounter time and again," he said. "A compulsory capacity commitment is not risk-free."

Manuel Esquivel of Enel North America also expressed support, saying the status quo is not just and reasonable.

Tom Hoatson of LS Power also called for change to the offer cap, saying current rules result in "over-mitigating." He said his company supports the PJM proposal with several revisions, including that the CPQR should be based on the market seller's view of the risk of taking on a capacity obligation.

"This risk is viewed differently by different market sellers, and the market seller's view of this risk is commercially sensitive," he said. "One size doesn't fit all, and the process needs to reflect that."

LS Power also would change the deadline for requesting an exception to the must-offer requirement, making it at least five days after receipt of the final unit-specific MSOC value from PJM and the IMM. The current deadline is the same day as when the final MSOC is issued.

Hoatson also said all models, data and methodologies that the Monitor and PJM use to make their determinations should be made available to the market seller before their decisions are made.

Assistant General Counsel Eric Scherling | © *RTO Insider LLC*

Under the current rules, "it's a black box," Hoatson said. "We don't know how the numbers were arrived at, so we can't debate them with the IMM and PJM. Perhaps we're wrong. Perhaps the other side is wrong. We don't know."

GreenHat Payments Expected by January

PJM Assistant General Counsel Mark Stanisz told members that the RTO should receive $1.375 million in disgorgements from the principals of the defunct GreenHat Energy by the end of January.

Under settlements approved by FERC on Aug. 19, two of GreenHat's founders and the estate of the third agreed to pay the disgorgements. The principals also consented to the entry of a $179.6 million judgment against the company, reflecting the losses suffered by PJM market participants when GreenHat defaulted on its obligations in the financial transmission rights market in 2018. (See *FERC OKs GreenHat Settlements*.)

But PJM has no hope of recovering any of the nearly $180 million, Stanisz said. GreenHat "has no funds and no assets," he said.

FERC ordered PJM to distribute the disgorged monies "in a reasonable manner" approved by the commission's Office of Enforcement. The RTO said it will likely do so in a single distribution.

In response to a request from Constellation, PJM said it would advise market participants

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where they will see the disbursements in their billing statements.

Revised Bankruptcy Rules

PJM proposed *changes* to its credit policies to provide greater protections against bankruptcies by market participants, the RTO's latest response to the GreenHat default.

The revisions would clarify that PJM has a first priority security interest in market participants' cash deposits.

PJM would also require that a party filing for bankruptcy immediately address the RTO's rights with a "first day" motion ensuring the full repayment of pre-petition obligations and the continuation of post-petition obligations.

The new language aims to demonstrate to bankruptcy courts that PJM has interests that are set apart from "garden variety" creditors, Assistant General Counsel Eric Scherling told the MRC. Though there are limitations on PJM's ability to compel action from parties that have filed for bankruptcy, the revisions are aimed at making the proceedings go more smoothly to mitigate potential losses from delays.

"PJM is different, and we want to basically do whatever we can … to lay the groundwork as to why PJM is different," Scherling said.

Tariff language would be changed to clarify that FTR transactions "are entitled to the special protections given to 'forward contracts,' 'swap agreements' and 'master netting agreements'" under the U.S. Bankruptcy Code, including exceptions from automatic stays and allowing for immediate termination or liquidation.

The revisions were endorsed by the Risk Management Committee in July after meeting to discuss the issue six times. The proposal is expected to go before the MRC for approval next month.

FERC already approved revisions to PJM's credit policy for FTR transactions in September 2018, setting a minimum credit requirement for FTRs equal to 10 cents/MWh (ER18-2090).

FTR Manual Changes Endorsed

The MRC endorsed *revisions* to Manual 6: Financial Transmission Rights as part of a periodic review and changes to conform with tariff revisions intended to increase the transparency and efficiency of the RTO's auction revenue rights and FTR markets. The changes were approved by FERC in March (*ER22-797*). (See *FERC Accepts PJM ARR/FTR Market Changes*.)

Variable Environmental Costs and Credits Rules OK'd

Members approved an *update* to rules governing variable environmental charges and credits and their inclusion in cost-based energy offers. Generation units receiving production tax credits or renewable energy credits must reflect them in their fuel-cost policies when submitting non-zero cost-based offers into the energy market. The changes will include revisions to Manual 15: Cost Development Guidelines and Operating Agreement Schedule 2. (See "Variable Environmental Costs and Credits," *PJM MIC Briefs: May 11, 2022*.)

Johnson thanked PJM for addressing Old Dominion Electric Cooperative's concerns regarding differentiating fuel costs from emissions costs.

The update will be brought to a Members Committee vote in September. ■

— Rich Heidorn Jr. and Devin Leith-Yessian

NJ BPU Denies Deadline Extensions for Solar Project Incentives

By Hugh R. Morley

New Jersey's Board of Public Utilities (BPU) earlier this month denied requests by 15 solar developers seeking to extend the completion deadlines for 37 projects.

While the board at its regular meeting Aug. 17 also granted extensions for hundreds of other projects, members expressed reluctance over the denials, as the state faces its own deadline crunch on its renewable energy goals and developers face financial uncertainty and supply chain challenges.

The series of decisions affect participants in the state's temporary Transition Incentive (TI) program. Now closed to new projects, it provided incentives of between $91.20 and $152/MWh. Projects that aren't finished by the deadline — initially a year from the project approval — and do not receive an extension would lose the incentive and have to apply to the less lucrative program that succeeded TI.

The BPU said the 15 developers had failed to show sufficient evidence that delays to their projects' construction were caused by events beyond their control. At the same time, it approved a six-month deadline extension for hundreds of public entities, including schools, universities and municipalities. And the board granted a deadline extension of up to a year for 30 projects planned on a landfill, brownfield or area of historic fill.

The board also approved a six-month extension for four projects approved for TI benefits as part of the state's community solar program, but it denied an extension to five other projects in the program, saying they were too far from completion.

Providing Certainty

Outlining the decisions at the meeting, Scott Hunter, manager of the BPU's Office of Clean Energy, said they were aimed at "providing clarity, certainty and support" for solar projects while limiting the cost to ratepayers of extending the deadline and allowing projects that miss their deadline to remain in a higher incentive program.

BPU President Joseph Fiordaliso told the board that the votes demonstrate "the desire of this board to work with the solar industry" while reducing the burden on ratepayers.

The BPU created the TI program to help reshape the state's incentive programs away from the Solar Renewable Energy Certificate (SREC) Program, which dispensed incentives of about $250/MWh for more than a decade until it closed in April 2020. With incentives about half the size of the SRECs, TI followed in May 2020 but was closed soon after the BPU in July 2022 approved the permanent Successor Solar Incentive Program, with incentives between $70 and $100/MWh.

Navisun's 4.5-MW Linden Hawk Rise community solar project, located on a former landfill site in Linden, N.J. | *Navisun*

The shift stemmed from a 2018 state law that directed the BPU to close the SREC program once it reached 5.1% of the power sold. That happened on April 30, 2020. (See *Solar Subsidy Program Ending in New Jersey*.)

BPU data for the first half of 2022 show the state is on track to meet a 2025 goal of 5.2 GW of capacity set out in the state *Energy Master Plan* but needs a dramatic increase in annual capacity installed to meet goals of 12.2 GW in 2030 and 17.2 GW in 2035. (See *NJ Faces Challenges as Solar Sector Hits 4 GW*.)

Mixed Bag

Fiordaliso said that the state has cultivated and supported the solar industry for 20 years, and the decision to grant only certain extensions reflected that strategy of reducing financial support.

"The industry knew that eventually they were going to get closer to standing on their own two feet," he said. "We did nothing in secret. We did it in conjunction with the stakeholders. And I think the state of New Jersey has thrived. I think the developers have thrived. And if we continue to work together, we will continue to maintain the solar industry as a major industry here in the state of New Jersey."

The board voted 4-0 on the extensions, with one abstention. Commissioner Zenon Christodoulou, who joined the board on Aug. 15, didn't vote in the meeting because he felt that he needed more time to study the issues.

Commissioner Bob Gordon said that any government support for an industry "needs to balance the goals of advancing the new industry against the cost impact."

"At some point, you need to cut back on those incentives," he said. "When that industry grows up, if you don't do that, the risk is the ratepayers subsidize inefficiency. And that's not what we want to do."

Scott Elias, manager of Mid-Atlantic state affairs for the Solar Energy Industries Association (SEIA), called the board's votes a "mixed

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bag for the industry."

"It is our opinion that an orderly transition from the Transition Incentive program to Solar Successor Incentive Program ought to recognize that industry is not immune to COVID-19 or global economic trends that leave customers navigating a supply chain riddled with bottlenecks and delays," he said.

"It's great that the BPU made limited extensions for some community solar projects and projects serving public entities," he said. "But markets cannot efficiently operate when power purchase agreements need to be retroactively renegotiated because projects literally can't be built, interconnected and operating in a narrow 12-month timeline due to unavoidable delays caused by the COVID-19 pandemic."

Elias also said the extensions for the 30 brownfield projects "will not address the PJM interconnection delays associated with every [brownfield] project that followed the rules and applied before the closure of the TI program in August of 2021."

"Put simply, the order insufficiently addresses all of the concerns that led to the introduction and passage of A4089," a *bill* that would automatically extend the completion date for brownfield solar projects that cannot be completed because of interconnection problems caused by PJM or a utility. The General Assembly passed it unanimously in June, but the Senate has not acted on it. Another trade group, NJ Utility Scale Solar, has backed the legislation and called for a "blanket" *deadline extension* for TI projects.

Deadline Extension Guidelines

BPU officials gave varying reasons for the extension denials or approvals.

The rejected 37 projects were "not mature enough to meet TI deadlines," the BPU said in its *order*. The projects all filed their application shortly before the TI program was closed and cited supply chain difficulties as preventing completion. But developers "knew, or should have known, that they were not going to be able to complete their projects within the time frames enumerated in the TI rules," the BPU said.

The board noted that in June, it *granted* a request by ESNJ-Key-Gibbstown to extend the deadline on a 1.38-MW carport solar project in Gibbstown. The board had already granted the project two deadline extensions, and the developer — faced with an April 30 deadline by which to show project completion — sought an additional extension of three months.

The developer argued that it had completed the project but could not interconnect it because Atlantic City Electric had not performed the necessary transmission upgrades.

In granting Gibbstown the extension, the BPU laid out general guidelines on when it would be appropriate to override TI project rules. One of them requires the project to show that the project was electrically and mechanical complete before the deadline expired and had received the necessary final inspections. They also require that the developer show that the utility had committed in advance to completing any upgrades needed to interconnect the project by the deadline but, "despite the developer's best efforts, the estimated upgrade completion date was unilaterally extended by the" utility.

The 37 projects denied an extension did not demonstrate those conditions, the BPU said. ■

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NJ Faces Challenges as Solar Sector Hits 4 GW

NetZero Insider

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

SPP News

SPP Briefs

Platte River Joins Western Utilities Evaluating RTO Membership

SPP on Thursday welcomed Colorado utility Platte River Power Authority as the latest Western utility to provide a notice of intent to evaluate participation in the grid operator's planned RTO West.

Platte River is the eighth Western entity that has publicly committed to exploring SPP's RTO expansion. The utility has already *announced* plans to join the RTO's Western Energy Imbalance Service (WEIS) market next April.

"We look forward to joining the WEIS next year and SPP's RTO in 2025," Platte River COO Melie Vincent said.

SPP administers the WEIS market on a contract basis and provides participants with a suite of services including market administration, transmission planning, reliability coordination and more. It says WEIS participants that become full RTO members can expect to receive similar *savings and benefits* as its Eastern Interconnection members. According to the grid operator, those members saved $2.696 billion last year, a benefit-to-cost ratio of 18-to-1 given $149 million in net revenue requirement costs.

The RTO has set a March 2023 target for Western utilities to indicate their intent to participate in its initial expansion into the interconnection. SPP expects to extend its RTO into the West in March 2024.

"We are pleased that Platte River will be joining the WEIS market next year and is evaluating the cost and benefits of full RTO membership," said Bruce Rew, SPP's senior vice president of operations. "Our continued collaboration will enable us to help them reliably and economically serve their communities while meeting their clean energy goals."

Basin Electric Power Cooperative, Colorado Springs Utilities, Deseret Power Electric Cooperative, Municipal Energy Agency of Nebraska, Tri-State Generation and Transmission Association, Western Area Power Administration and Wyoming Municipal Power Agency are the other entities that have already expressed interest in the RTO.

MMU Releases WEIS Spring Report

SPP's Marketing Monitoring Unit (MMU) last week released its WEIS quarterly *State of the Market report* for the spring period, which covers March through May 2022.

The MMU said it believes that the WEIS "functioned as expected" during its second spring quarter of operations. It said the market continues to struggle with ramp availability and short-term system flexibility despite an abundance of online capacity but noted those issues have persisted since it began operations in February 2021.

The Monitor said many dispatchable resources are offered with minimal available dispatchable and/or rampable capacity. "Market participants are also reluctant to offer additional resources due to risks associated with recovering costs when prices drop," the MMU said.

It noted SPP has begun conversations with market participants to discuss offered rampable capacity and encourages more capacity to be offered to increase market efficiency. "The MMU supports the incremental improvements to the market enacted during this period and continues to recommend further enhancements," it said.

Average load prices during the period were

Platte River Power Authority's Rawhide Prairie Solar project | *Platte River Power Authority*

SPP News

consistent with the year prior at $15.71/MWh and $19.48/MWh for March and April, respectively, and increasing to $26.85/MWh in May. Coal remained the predominate fuel source ahead of hydropower, accounting for 66% of the market's generation in March before dropping to 59% by May.

SPP administers the market for 12 utilities, centrally dispatching energy from participating regional resources every five minutes.

RTO, AECI to Target Efficient Joint Solutions

SPP staff told stakeholders last week that they will be taking additional steps this year as they work across the seam with a neighboring cooperative to identify interregional projects.

Neil Robertson, the RTO's coordinator of system planning, said during a joint stakeholder planning meeting with Associated Electric Cooperative Inc. (AECI) on Wednesday that the staffs are going to work with local transmission owners to find the best solutions for their needs.

"In years past, I felt soliciting for transmission solutions for all the needs was not efficient. As we refined [the solutions], we discovered we might not have a true jointly funded opportunity," Robertson said.

SPP has already analyzed updated models and contingency files provided by AECI and found more than 90 thermal and voltage needs. He promised a review of proposed solutions and to discuss potential joint projects when staff next meet with AECI and stakeholders later this year.

"We got some good project solutions, but when we've looked at that through a joint system plan with AECI, the benefits went to one or the other," Robertson said. "In this refinement, we'll do some additional due diligence to ensure that the opportunities that move forward clearly demonstrate a shared reliability need and shared benefits. I think this will increase overall efficiencies."

RFP out for NM Project

SPP has issued a *request for proposals* in soliciting bids for the 345-kV Crossroads-Hobbs-Roadrunner project in eastern New Mexico.

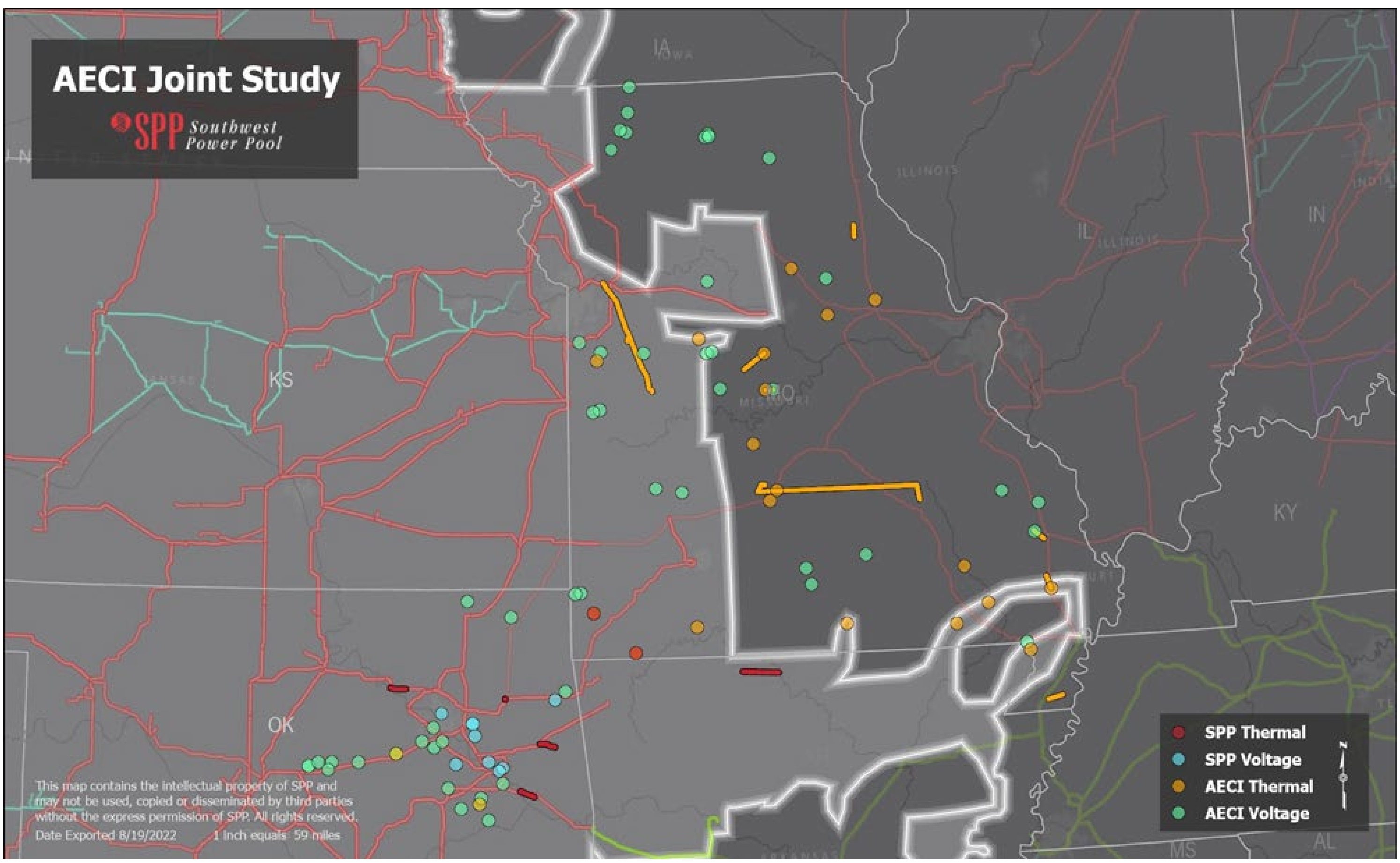
Companies soliciting proposals will need to include a $50,000 deposit for each response. Each deposit will be held in a segregated interest-bearing account in the respondent's name.

Notices of intent to submit an RFP response are due Nov. 23. The final deadline for responses and deposits is Feb. 21, 2023. A pre-response open meeting will be held Sept. 23 for qualified RFP participants to ask questions and get feedback.

The project, proposed by Southwestern Public Service, was approved in July as part of the 2021 Integrated Transmission Plan. The project was re-evaluated after load-projection errors were discovered in the original solution. (See "Members Approve SPS Tx Project over Staff's Recommendation," *SPP Board of Directors/ Members Committee Briefs: July 26, 2022*.)

Staff said in July the project would likely qualify as competitive under FERC Order 1000. The grid operator has already awarded four such projects. ■

— Tom Kleckner



Thermal, voltage needs on the SPP-AECI seam | *SPP*

SPP News

FERC Rules for SPP in AECI Dispute

Seam Neighbors at Odds over Winter Storm Emergency Energy Sales

By Tom Kleckner

FERC last week ruled in favor of SPP in its dispute with Associated Electric Cooperative, Inc. (AECI) over emergency energy transactions during the February 2021 winter storm, finding that the RTO properly compensated the cooperative in accordance with its tariff (*EL22-54*).

In its Aug. 22 order, the commission also granted SPP's request that FERC assert exclusive or primary jurisdiction over the emergency energy sales from AECI. FERC ruled the emergency transactions were made under a commission-jurisdictional tariff and said, "Therefore, the sales fall within the commission's jurisdiction to regulate."

SPP filed the request in April, asking FERC to act expeditiously to preserve its exclusive jurisdiction over the issues in dispute, given that AECI took its complaint in February to the U.S. District Court for Western Missouri (6:22cv3030). (See "SPP Takes AECI Dispute over Winter Storm Charges to FERC," *SPP Briefs: Week of May 2, 2022*.)

At issue is SPP's compensation for AECI's emergency assistance during the winter storm. The Missouri cooperative sold power into SPP's real-time balancing market and submitted respective tags for the transactions. The RTO settled each of AECI's transactions over Feb.15-19 using the real-time balancing market locational marginal pricing.

The cooperative is seeking to recover $37.64 million from SPP for the emergency power it provided during the storm. That includes $29.4 million for the costs to provide the power and $8.24 million in day-ahead residual unit commitment make-whole payments SPP has charged the cooperative.

SPP's Market Monitoring Unit intervened in the docket and asserted that FERC "unquestionably has primary jurisdiction" over the amounts SPP paid to AECI for emergency energy. The Monitor said that contracts for wholesale power sales must be filed at FERC and that there are no oral agreements for wholesale power sales. It also argued that the emergency energy transactions were not oral agreements but instead were conducted under the SPP-AECI joint operating agreement and the RTO's tariff.

In a separate order, FERC denied AECI's waiver request of SPP's 365-day limitation period for modifications to settlement statements in its attempt to reach a settlement with the grid operator (*ER22-2136*).

The commission had twice previously granted AECI 60-day extensions to allow extra time to reach a mutually agreeable resolution with SPP over its costs to supply the RTO with emergency energy during the storm. However, it said AECI's latest request did not address a concrete problem, as required by FERC's criteria for waivers.

The cooperative said its latest request would have given it and SPP more time to resolve the ongoing dispute. The commission noted that SPP said the payment dispute remains unchanged and that the grid operator's view was that no progress can be made.

Wind Farm's Appeals Denied

FERC last week also rejected Salt Creek Solar's request for a waiver requiring SPP to reinstate the company's interconnection queue position and dismissed a complaint alleging the grid operator violated the Federal Power Act (FPA) and its tariff by requiring Salt Creek to post an excessive amount of financial security to maintain its queue position (*ER21-2878, EL22-11*).

Salt Creek said it submitted an interconnection request in 2017 for a 228-MW solar generating facility in Nebraska. It said it didn't hear back from SPP until October 2020 — when it was allocated $146 million in network upgrade costs — after the RTO cleared its queue backlog. Salt Creek said a modeling error reduced that amount to $54 million, but it was revised again to $184 million when SPP published its second phase results.

The developer contended that the revised results required Salt Creek to post a $35 million deposit, identical to what it owed after the second phase. It said SPP continued to process higher-queued interconnection requests under its prior processes and that numerous withdrawals occurred. In April 2021, SPP notified interconnection customers that the study cluster would need to be restudied because of the withdrawals, Salt Creek said.

The grid operator eventually notified the developers that their request was deemed to have been withdrawn because Salt Creek did not pay the deposit within the required time.

FERC says AECI's emergency energy sales to SPP during the 2021 winter storm were properly compensated. | *AECI*

FERC found in its Aug. 22 order that Salt Creek's request for waiver to cure its nonpayment after receiving notice of its deemed withdrawal was retroactive and prohibited by filed rate doctrine.

The commission also denied Salt Creek's complaint that SPP had violated the FPA because the wind farm's developers did not meet their burden under the act to demonstrate that the RTO had violated its tariff or the FPA.

Commissioner Mark Christie concurred in a separate statement, pointing to FERC's 2021 order that granted Lookout Solar Park, part of the same cluster with Salt Creek, a waiver to pay its financial security after the restudy's results were available. He said, "Unsurprisingly, the commission is now faced with having to grant an untenable number of waiver requests or deny the same relief to other customers, like Salt Creek, that may indeed be similarly situated."

Quoting former Congressman Barney Frank (D-Mass.), Christie said, "The biggest lie in politics is when a politician says, 'I hate to say I told you so,' because, as Frank put it, 'Everybody loves to say it.'"

"I told you so," Christie concluded. ■

Company Briefs

Toyota Drops Lawsuit Against California, Emission Rules

Toyota last week agreed to recognize California's authority to set its own auto emission standards, ending a standoff stretching back to the Trump administration.

The automaker, which sued along with several other manufacturers to stop California from setting higher emissions standards than the federal government, said in a statement that it has acknowledged the California Air Resources Board's "leadership in climate policies and its authority to set vehicle emissions standards under the Clean Air Act."

CARB is set to adopt new vehicle emission rules that would result in about 50% of cars being zero-emission models by 2035 and nearly 90% by 2045. If the board adopts the regulations, they will be submitted to the federal EPA for approval.

More: *Los Angeles Times*

ND PSC's Fedorchak Appointed to EPRI Advisory Council

The Electric Power Research Institute last week appointed North Dakota Public Service Commissioner Julie Fedorchak to a three-year term on its advisory council.

The council offers advice and comments to EPRI regarding its current research programs and provides leadership to support senior management and the board of directors in carrying out the public interest mission of the organization.

More: *ND PSC*

Vistra Names Doré Chief Strategy, Sustainability Officer

Vistra last week announced that Stacey Doré joined the company as its first chief strategy and sustainability officer and executive vice president of public affairs, effective Aug. 23.

Doré most recently served as president and chief executive officer of Hunt Utility Services and Sharyland Utilities, an ERCOT utility, from 2019-2021.

More: *Vistra*

Federal Briefs

BLM Approves LaBarge Carbon Storage Project

The Bureau of Land Management last week approved the LaBarge oilfield's carbon storage project in Wyoming.

According to BLM, the well is expected to permanently store about 60 million cubic feet of carbon dioxide per day approximately 18,000 feet underground beneath Lincoln and Sweetwater counties.

Natural gas trapped in the oilfield near ExxonMobil's Shute Creek Gas Plant contains an unusually high proportion of carbon dioxide. The facility separates and sells millions of tons of the carbon dioxide produced from drilling each year, primarily for enhanced oil recovery. The plant is already responsible for close to 20% of all human-made carbon captured annually, according to Exxon, which announced last October it had finalized plans to increase capture capacity by about 15% and begin storing some of that carbon dioxide underground.

More: *Billings Gazette*

FERC Gives Mountain Valley Pipeline More Time to Complete Project

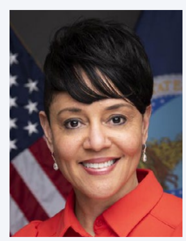
FERC last week granted Mountain Valley Pipeline four more years to complete its $6.6 billion natural gas pipeline, which will run through West Virginia and Virginia.

Mountain Valley requested more time in June following repeated delays caused by litigation from groups concerned about the project's environmental impact.

The new deadline for completion is October 2026.

More: *The Roanoke Times*

USDA Invests in Critical Infrastructure to Combat Climate Change



U.S. Department of Agriculture Deputy Secretary **Dr. Jewel Bronaugh** last week announced that the USDA is investing $121 million in critical infrastructure to combat climate change across rural America in "socially vulnerable communities."

The investments include $111 million for 289 projects and will help people in 49 states, along with Guam and Puerto Rico.

More: *USDA*

State Briefs

ILLINOIS

Judge Dismisses $150M Class Action Lawsuit Against ComEd

A federal appellate court judge last week dismissed a $150 million class action lawsuit against ComEd and its parent company, Exelon, over a bribery scandal involving former House Speaker Michael Madigan.

The Racketeer Influenced and Corrupt Organizations Act class action suit was filed by nine consumers in hopes of reimbursing residents for electricity rates that ComEd raised following its participation in the scheme. However, the judge ruled that paying a state's required utility rate was not a recognizable injury for a damage claim.

ComEd paid a $200 million fine in 2020.

More: *WTVO*

KENTUCKY

Siting Board Approves Logan Solar Project

The State Board of Electric Generation and Transmission Siting last week approved a 173-MW solar facility in Logan County despite many public concerns. The approval stands as long as all recommended mitigation measures are implemented.

The project has received criticism from local farmers and residents who are concerned about taking agricultural land out of production and whether the decommissioning process will be enough to return the land to its current value after the project's 30- to 40-year life. The board noted the concerns but said its statutory authority under state law does not extend to deciding the "best use of land" or "selecting a different location for the project."

More: *Bowling Green Daily News*

MINNESOTA

PUC Approves Permits for Solar, Wind Hybrid Projects

The Public Utilities Commission last week approved site permits and transmission routes for Apex Clean Energy's Big Bend Wind and Red Rock Solar projects.

When complete, the sites will produce about 300 MW of wind power and up to 60 MW of solar generation. The plan is to install 55 turbines at the Big Bend project and solar panels on more than 480 acres on nearby land for the Red Rock project. It will be the state's largest hybrid renewable energy project.

The PUC also approved a permit for an 18-mile transmission line to connect to the grid.

More: *MPR News*

OHIO

OPSB Approves Van Wert Solar Facility

The Power Siting Board last week approved applications filed by Wild Grains Solar and Nottingham Solar to construct solar facilities in Van Wert and Harrison counties.

The 150-MW Wild Grains Solar facility will occupy 818 acres in Van Wert County. The 100-MW Nottingham facility will occupy 580 acres in Harrison County.

More: *Paulding Country Progress*

PUC Freezes Investigations into FirstEnergy Bribes

The Public Utilities Commission last week unanimously voted to pause its four investigations into FirstEnergy's conduct in a bribery campaign. The move came at the request of Kenneth Parker, the U.S. Attorney for the Southern District of Ohio. The pause will last at least six months and is subject to renewal.

FirstEnergy signed a deferred prosecution agreement last summer, agreeing to pay a $230 million fine and cooperate with prosecutors to possibly avert a criminal charge of honest services wire fraud. In the agreement, the company stated it paid $60 million into an account controlled by then-House Speaker Larry Householder and $4.3 million to a business operated by then-PUC Chairman Sam Randazzo, in exchange for "official action" in the form of legislation and regulatory decisions.

Commissioner Daniel Conway said it's important that the PUC not create "material risks" to the criminal investigation.

More: *The Ohio Capital Journal*

OREGON

Idaho Power Company to Pay $1.5M Civil Settlement for Fires

The U.S. Attorney's Office for the District of Oregon last week announced that Idaho Power Company has agreed to pay $1.5 million to settle allegations related to the May 2014 Powerline and August 2015 Lime Hill fires in Baker County.

The Powerline Fire burned approximately 5 acres of federal land managed by the Bureau of Land Management, while the Lime Hill Fire burned approximately 2,592 acres of federal land and 9,337 acres of privately owned land.

More: *U.S. Attorney's Office for the District of Oregon*

Portland Adopts Limits on Fossil Fuel Terminals

The Portland City Council last week voted to limit the expansion of fossil fuel terminals in the city.

The zoning code change prohibits the construction of new fossil fuel terminals and prevents any of the city's existing 11 terminals from expanding. The existing terminals are referred to as the Critical Energy Infrastructure hub. The area houses about 90% of the gasoline, diesel and jet fuel used in Oregon and Southwest Washington.

A study commissioned in 2020 found between 95 million and 194 million gallons of fuel could be released in a major earthquake. The fuel would spew into the air as well as into the Willamette River and cause $359 million to $2.6 billion in damages.

More: *Oregon Public Broadcasting*

TENNESSEE

Memphis Hires Consultant to Study MLGW-TVA Split

The Memphis City Council last week hired energy consultant Tabors Caramanis Rudkevich to review Memphis, Light, Gas and Water's study of its options outside of the Tennessee Valley Authority.

That first integrated resource plan outlined several different portfolios for MLGW that included a combination of natural gas, solar power and energy from MISO.

MLGW is set to release its recommendations as to whether the utility should leave TVA on Sept. 1. It has been receiving bids on its power supply for most of the year.

More: *Memphis Commercial Appeal*

TEXAS

Comptroller Bans Firms that Boycott Fossil Fuels

The state banned 10 financial firms and 348 investment funds from doing business with the state after Comptroller Glenn Hegar said they did not support the oil and gas industry.

Hegar banned BlackRock and other banks and investment firms — as well as some investment funds within large banks such as Goldman Sachs and JP Morgan — from entering into most contracts with state and local entities after his office said the firms "boycott" the fossil fuel sector. Hegar sent inquiries to hundreds of financial companies earlier this year requesting information about whether they were avoiding investments in the oil and gas industry in favor of renewable energy companies.

More: *The Texas Tribune*

VIRGINIA

Dominion Says Guarantee for OSW Farm 'Untenable'

Dominion Energy last week filed a petition with the State Corporation Commission asking it to reconsider its decision to include a ratepayer protection order in its approval of the utility's $9.8 billion wind project off Virginia Beach.

The commission's order included three "consumer protections," including a performance guarantee. It said that beginning with the commercial operation and extending through the life of the project, customers will be "held harmless" for any shortfall in energy production below a 42% annual net capacity factor, measured on a three-year rolling average. The standard would protect customers "from also having to pay for replacement energy if the project does not generate the amount of electricity upon which Dominion bases its request and its cost estimates," the commission said.

Dominion argued the commission lacks the authority to impose a performance guarantee and that doing so would be contrary to the intent of the General Assembly, which paved the way for the project with an overhaul of the state's energy law in 2020. The utility also argued the standard is unreasonably broad in scope and would hold it responsible for events out of its control. If the order is not revoked, Dominion said it may have to scrap the project.

The commission agreed to hear more arguments on the project.

More: *The Associated Press*, *The Associated Press*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