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RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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Stakeholder Soapbox

Coherence over Chaos: Choosing the Right Path for Energy Decarbonization

By Paul Segal and Reid Capalino, LS Power

LS Power CEO Paul Segal | *LS Power*

As the U.S. and other countries seek urgently to reduce greenhouse gas emissions amid a backdrop of global energy market volatility, we are confronted with a fork in the road: the "chaotic" path for decarbonization, which at times appears to be the market's current trajectory, versus the "coherent" path — the path we strive to follow.

Reid Capalino, SVP business development for LS Power | *LS Power*

What, though, will make the energy transition chaotic versus coherent, and why does it matter? The chaotic path is characterized by opposing extremes that reflect the current polarization around energy discourse — those ignoring the imperative to decarbonize, and those seeking a fossil-free end-state on an unrealistic timeline in terms of cost and risks to system reliability.

The coherent path involves embracing both rapid deployment of low-carbon energy resources and maintenance of sufficient fossil-fuel infrastructure to ensure continued energy security, affordability and reliability as our economy transitions toward net-zero GHG emissions.

According to the International Energy Agency's (IEA) *modeling*, a long-term net-zero trajectory will see U.S. fossil-fuel consumption decline by more than half in the next 20 years, caused by enhanced energy efficiency and increased focus on renewables such as wind and solar. Yet in this scenario, fossil-fuels in 2040 will still serve nearly 40% of total energy demand, including oil for transportation and natural gas for power plants, industrial facilities and buildings. The expected decline in conventional gas-fired power generation is even more dramatic: an 89% reduction from 2020 levels.

As one of the largest owners of gas-fired assets in the U.S. focused on a sustainable energy transition, we fully appreciate and understand the long-term need to reduce unabated gas-fired generation to meet our climate goals.

Simply emphasizing an end-state of 2040, however, glosses over several complexities in this transition, as reflected in the IEA's modeling of a low-carbon future:

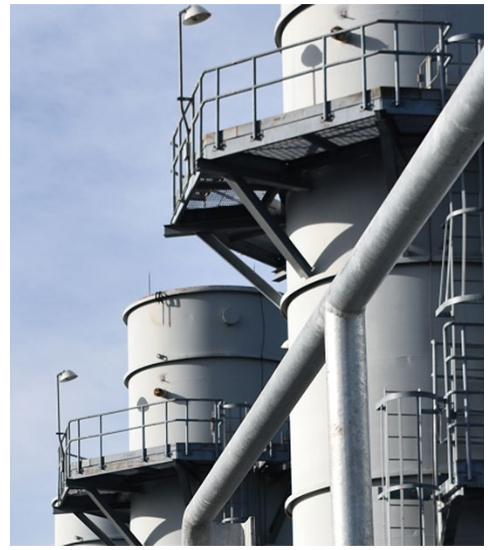
- Much of the gas-fired generation decline would occur after 2030.
- This decline would occur, in part, by aggressive deployments of emissions-reducing technologies, such as battery storage and those capturing and sequestering CO2 emissions from power and industrial facilities, which will require new policies to overcome economic and technical obstacles.
- Throughout this transition, standby gas-fired generation will remain necessary to ensure energy reliability during peak weather events (e.g., extremely cold or hot temperatures) when renewable energy sources alone may be insufficient to balance supply and demand. Even as gas-fired generation shifts from providing energy (megawatt-hours) to providing capacity (megawatts), hundreds of power plants with some nexus to the natural gas system will likely need to remain in operation.

Unfortunately, states such as Illinois are mandating the retirement of gas-fired generators without adequately planning to replace the flexible capacity that such generators provide or analyzing the net impact that these retirements will have on GHG emissions.

Shortsighted retirement mandates will lead to a chaotic energy transition, thereby eroding the political support needed for the transition to progress. We should instead consider how maintained and repurposed fossil-fuel infrastructure can preserve reliability as we rapidly increase use of renewable energy — understanding that maintenance/repurposing of existing infrastructure and development of new low-carbon energy sources both require significant investments now.

So, what can we do to support a more coherent path for decarbonization?

- Support long-term federal tax credits and state-level incentives for low-carbon energy sources, and advocate for policies that value the flexibility of gas-fired generators.
- Advocate for tighter environmental standards to reduce fugitive methane emissions through the natural gas value chain, and support judicious investment in natural gas infrastructure, such as pipelines and associated compression/storage facilities to deliver gas when needed, liquefied natural gas terminals to help balance domestic gas markets, and upstream natural gas production to ensure a continued robust domestic supply.
- Support efforts to deploy new zero-carbon technologies and repurpose existing fossil-fuel infrastructure, such as retrofitting carbon capture onto existing power plants and industrial facilities.



LS Power's generation fleet includes more than 13,000 MW of fast-starting natural gas-fired plants to complement wind and solar resources. | *LS Power*

We urge everyone to understand where our energy system currently stands, where we want to be and what we need to do to get there. This process will require greater collaboration among companies, policymakers, activists and other stakeholders.

More coherence, not more chaos, is what we need to power our homes and businesses today while protecting the planet and strengthening the resilience of our energy system for tomorrow. ■

***Paul Segal**, who has been CEO of LS Power since 2011, is also a member of LS Power's Management Committee, overseeing one of the largest independent power and transmission developers in the U.S.*

***Reid Capalino** is senior vice president of business development at LS Power, leading the firm's business development efforts with a focus on growing existing business lines and launching new ones.*

DOE Initiative Aims to Make Interconnection 'Simpler, Faster, Fairer'

I2X to Tackle 1,400 GW of Clean Energy Waiting Years in Backed-up Queues

By K Kaufmann

The message from the June 7 launch of the Department of Energy's *Interconnection Innovation eXchange* (I2X) initiative was clear: To reach President Biden's goal of a U.S. electricity system powered 100% by clean power by 2035, interconnecting solar, wind and other clean energy projects to the grid must be made simpler, faster and fairer.

The *latest figures* from the Lawrence Berkeley National Laboratory (LBNL) show that more than 1,400 GW of mostly zero-carbon generation and storage projects are sitting in transmission interconnection queues across the country, with solar making up about half the total.

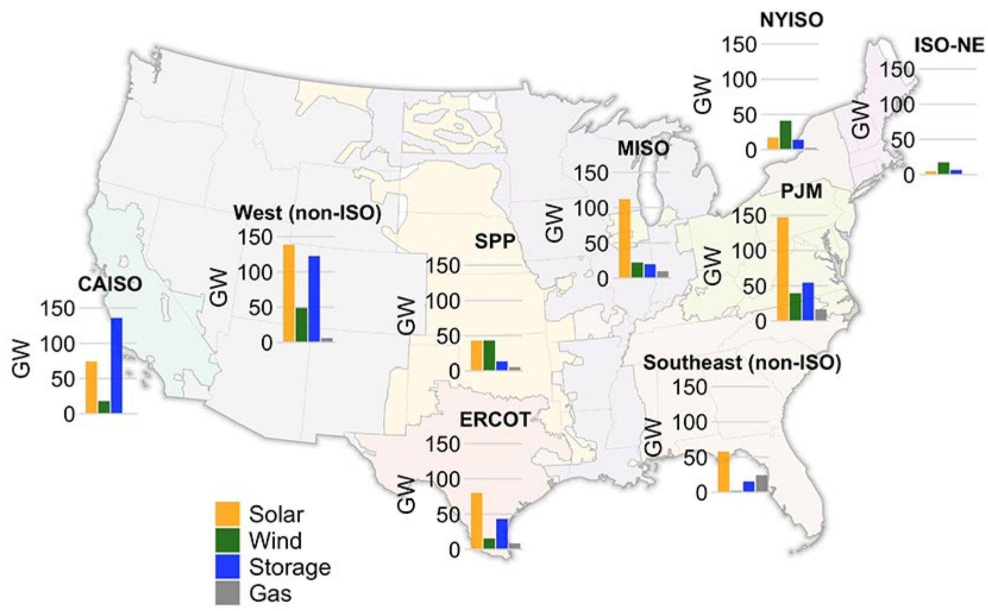
"This is mind-blowing to me," Energy Secretary Jennifer Granholm said in opening remarks at the virtual launch. "That 1,400 GW is about what we need to reach a critical milestone of 80% clean electricity by 2030. If we could get all that capacity online, imagine how much faster we could reach our climate goals."

Granholm acknowledged the challenges ahead are complex, if not daunting. LBNL also found that interconnection wait times are trending up, while project completion rates are falling. From 2000 to 2016, completion rates sat at 20% for solar projects and 16% for wind projects. In 2021, wait times had climbed to 3.7 years, up from 2.1 years a decade earlier.

Further, according to Alejandro Moreno, DOE deputy assistant secretary for renewable power, the time and cost of interconnection processes "tend to favor incumbents who have the resources and know-how to add new generation to the grid. [But they] can disadvantage new generation, particularly community-scale generation," he said.

"Because [these] projects tend to be smaller in scale, they're more sensitive to cost and become quickly too expensive to build," Moreno said.

Funded with $3 million from the Infrastructure Investment and Jobs Act, I2X hopes to untangle such issues by pulling in a broad range of stakeholders, setting up collaborative working groups, collecting and analyzing massive amounts of data and developing a five-year interconnection roadmap, Granholm said. The initiative will look at both transmission- and distribution-level interconnection.



About 1,400 GW of solar, wind and storage projects are sitting in interconnection queues across the country, facing average wait times of close to four years. | *Lawrence Berkeley National Laboratory*

About 200 companies and organizations have already signed up to participate, including CAISO, PJM, SPP and NERC, as well as major utilities such as National Grid, Xcel Energy and the Los Angeles Department of Water and Power.

With stakeholder engagement a core pillar of the initiative, Naomi Davis, founder and CEO of Chicago nonprofit Blacks in Green, said a commitment to ensuring communities are at the table will be essential. The need is real, she said, "but the practice requires a budget line item, and it requires metrics, concrete metrics for achieving equitable, meaningful engagement."

Speaking on the first of two stakeholder panels at the launch, Davis pointed to weatherization as a "threshold issue" for communities of color. "We have many seniors, homeowners who are entitled … to have the comfort, the security, the reliability of the new renewable energy that everyone is so excited about but which too few of our homes in the Black and brown community are prepared to receive. The deferred maintenance issue must be addressed," she said.

Danielle Sass Byrnett, director of the Center for Partnerships and Innovation at the National Association of Regulatory Utility Commissioners, spoke of the intensive stakeholder engagement processes now underway in several states as they roll out interconnection standards under IEEE 1547-2108. Implementing the standards for interconnecting distributed energy resources has taken multiple years of "learning about the standard, understanding the implications of different decision-making within the standard … and looking at the processes and speed of interconnection once you have the new standards in place," Byrnett said.

To help utilities and DER developers navigate the new rules, some states are experimenting with "interconnection ombudsmen or adjudicators," she said.

Models Don't Match Reality

Beyond simpler, faster and fairer, I2X has some ambitious goals, according to Tom McDermott, solar subsector manager at the Pacific Northwest National Laboratory, one of three National Laboratories working on the initiative with DOE. The other two are LBNL and the National Renewable Energy Laboratory.

By the end of the year, I2X will have defined and simulated interconnection process improvements, McDermott said. The first draft of the roadmap and an accompanying interconnection studies guide geared toward engineers are due March 31, 2023.

FERC/Federal News

"We also need to define achievable metrics for improvement over the five-year horizon, for example to reduce the cost and time of interconnection by 50%," he said. "The right number may vary by state, region or operating entity."

The roadmap will include separate sections for the bulk power and distribution systems and for large- and small-scale generation, McDermott said. "There may be different approaches for regulated and unregulated jurisdictions … and finally the roadmap will suggest mitigations for any costs, delays or uncertainties encountered in the transition from existing practice to a better set of practices."

Drilling into key interconnection issues on the second stakeholder panel, Ryan Quint, a senior manager at NERC, argued for I2X to have a strong focus on reliability.

"The current interconnection requirements and interconnection study processes are not equipped to handle the new resource base" of renewable energy, Quint said. "Some of the issues include component modifications and rework throughout the process, which adds complexity and slows down the process."

"We end up with models that are used in reliability studies … and these models don't match reality" and can ultimately create "a huge liability risk," he said.

"We need to recognize that reliability and speed of interconnection don't have to be conflicting objectives here," Quint said. "We need to develop measures of success that assess the root cause issues we face, not the symptoms."

For example, instead of measuring project dropout rates, Quint said, researchers should be looking at the number of studies "that are necessary because equipment changes were made at the last minute" or the disparities between interconnection requirements and processes.

Automation is Coming

Charlie Smith, executive director of Energy Systems Integration Group, boiled the metrics down to three main benchmarks. For faster interconnection, he wants the time from application to interconnection agreement cut to "two years or even months." To measure fairness, he said, the question will be, "[Are] our developers being saddled with unreasonable network upgrade costs, yes or no?"

To make the process simpler, he called for "a publicly transparent generator connection study process that allows developers to do their own analysis and have a sense of cost before submitting their project in order to reduce speculative projects."

Smith also pointed to "connect and manage" interconnection practices in Ireland, the U.K. and Germany. In these countries, he said, generation projects may be allowed to connect to a transmission system before completion of a wider set of system upgrades.

Brian Fitzsimons, CEO of GridUnity, sees interconnection as "a large, integrated data capture, data sharing and analysis problem that needs to be brought into the real-time, information-sharing world." He talked up his company's cloud platform for aggregating and validating data and automating engineering analysis.

"Automation of engineering analysis will reduce study times and can be applied to reduce the number of stages in the process and the number of complex decision points," he said. "As study cost and time come down, there won't be as much need for multiple go-no-go points in the interconnection process." ■

Southeast

Inflation Dampens Possible Memphis Exit from TVA

By Amanda Durish Cook

The Memphis city utility's hopes of leaving the Tennessee Valley Authority for MISO could be dashed by inflation and high interest rates that could slash potential savings, a consulting firm said last week.

GDS Associates compared the top two bids of the 27 proposals Memphis Light, Gas and Water (MLGW) received in response to its search for alternative energy suppliers as the utility met Thursday with its Board of Commissioners and the Memphis City Council. GDS evaluated the bids against MLGW's long-term partnership option with TVA, scoring the proposals on pricing, performance guarantees, proven experience, and technical capability.

The consulting firm estimated the utility could save almost $31 million annually with the higher-scoring bid and $9.4 million annually under the second bid over a 25-year period that included the utility's transition from TVA. The analysis assumed higher natural gas prices, higher capacity prices and higher interest rates than MLGW's 2020 integrated resource plan, which predicted the city could save between $100 and $120 million if the utility left the federal agency for a power mix of natural gas and solar power.

Potential Losses in New Environment

However, GDS Power Supply Principal Chris Dawson warned that the savings could quickly nosedive and turn into losses if inflation, gas and capacity prices, and interest rates all increase by 2028. He said the lower-scored portfolio could saddle MLGW with about $100 million dollars of additional annual costs; the higher-scored bid could lead to $25 million in annual losses.


GDS Associates' Chris Dawson | *MLGW*


MLGW discussed bids at the Benjamin L. Hooks Library in Memphis. The meeting was also livestreamed. | *MLGW*

Dawson's comments were met with audible rumblings in the conference room.

"This is just a reminder about how the world can change. I'm not trying to be a harbinger of doom and suggest it will be like this in 2028 … but it could be like this," Dawson said.

He said consumer demand and geopolitical events have quadrupled natural gas prices, increasing the risk involved in constructing a gas plant. He also pointed out that MISO's April capacity auction cleared the highest-ever prices for its Midwest region.

Dawson said he believed MLGW would call for less emphasis on natural gas fired generation were MLGW's IRP developed today.

A non-TVA arrangement will subject the utility to new risks, including regulatory permitting, a likely credit ratings downgrade, and construction delays, he said.

"Under your current situation with TVA, most of these things you don't even think about. It's an afterthought," Dawson said. "I'm not suggesting MLGW can't build out that infrastructure, but it's not cheap, it's not easy, and you don't do it overnight."

Concerned about its power costs, the utility began seriously considering a break with TVA in 2020 when it produced an integrated resource plan. It later issued an RFP based on the plan. (See *Memphis Muni Mulls Move to MISO*.)

MLGW is at a crossroads. It can select one of the bids and depart TVA for MISO's energy markets, maintain its current arrangement with TVA, or sign a long-term partnership

Southeast

agreement (LTPA) that will lower costs but tie the utility to TVA for at least two decades.

The federal agency's LTPA option will result in an immediate 3.1% reduction in base rate charges, keeping them steady through 2029 and allow MLGW to acquire up to 5% of its energy needs from renewable sources. However, the contract includes a stranded-cost obligation that will make the utility responsible for a percentage of TVA's future investments and follow MLGW if it decides to later leave TVA. The LTPA also requires a 20-year termination notice; MLGW's current agreement has a five-year exit notice.

"It's not easy just to say, 'Hey, let's sign up for the LTPA and figure this out later,'" Dawson said. "I'm not even familiar with agreements that have 20-year termination notices."

MLGW is TVA's largest wholesale customer, spending about $1 billion per year on electricity.

"It's not lost on anybody that unlike pretty much any other one of TVA's wholesale customers, MLGW does have a real opportunity to do something different," Dawson said. "No wholesale customers have successfully left TVA. They have a certain type of protection, a certain type of legacy that revolves around their transmission system. That means if you leave TVA, you have to do a lot of work, I mean a lot of work and invest billions of dollars."

GDS estimated that under the LTPA, MLGW will pay $78.77/MWh for energy from 2028 to 2047. If the utility leaves TVA for MISO and constructs its own transmission, it can expect to spend $78.20/MWh for energy in the same timeframe based on the best bids, Dawson said. He added he wasn't surprised by those numbers and said that under the more independent MISO option, MLGW will own its transmission links and be able to control its destiny.

$1B in Tx Upgrades

A Siemens analysis prepared for MLGW concluded the utility will require 2,400 MW of new firm import capacity to MISO South should it leave TVA. The technology company said that would entail two 500-kV lines spanning the Mississippi River into Entergy Arkansas' territory and a 230-kV line terminating in Entergy Mississippi's footprint. Siemens said it would take seven to eight years to build the lines at a cost of about $1.2 billion.

GDS included the new transmission facilities in considering all the potential costs of leaving TVA.

"As a utility, you just don't turn on a dime," Dawson said.

MLGW Board Chair Mitch Graves said things have changed since the utility began exploring bids. He said supply chains have become strained, inflation is squeezing customers and energy prices have climbed sharply.

"All of that has to come in our decision-making process," he said.

City council member Dr. Jeff Warren said MLGW might consider waiting for economic tensions to settle before proceeding.

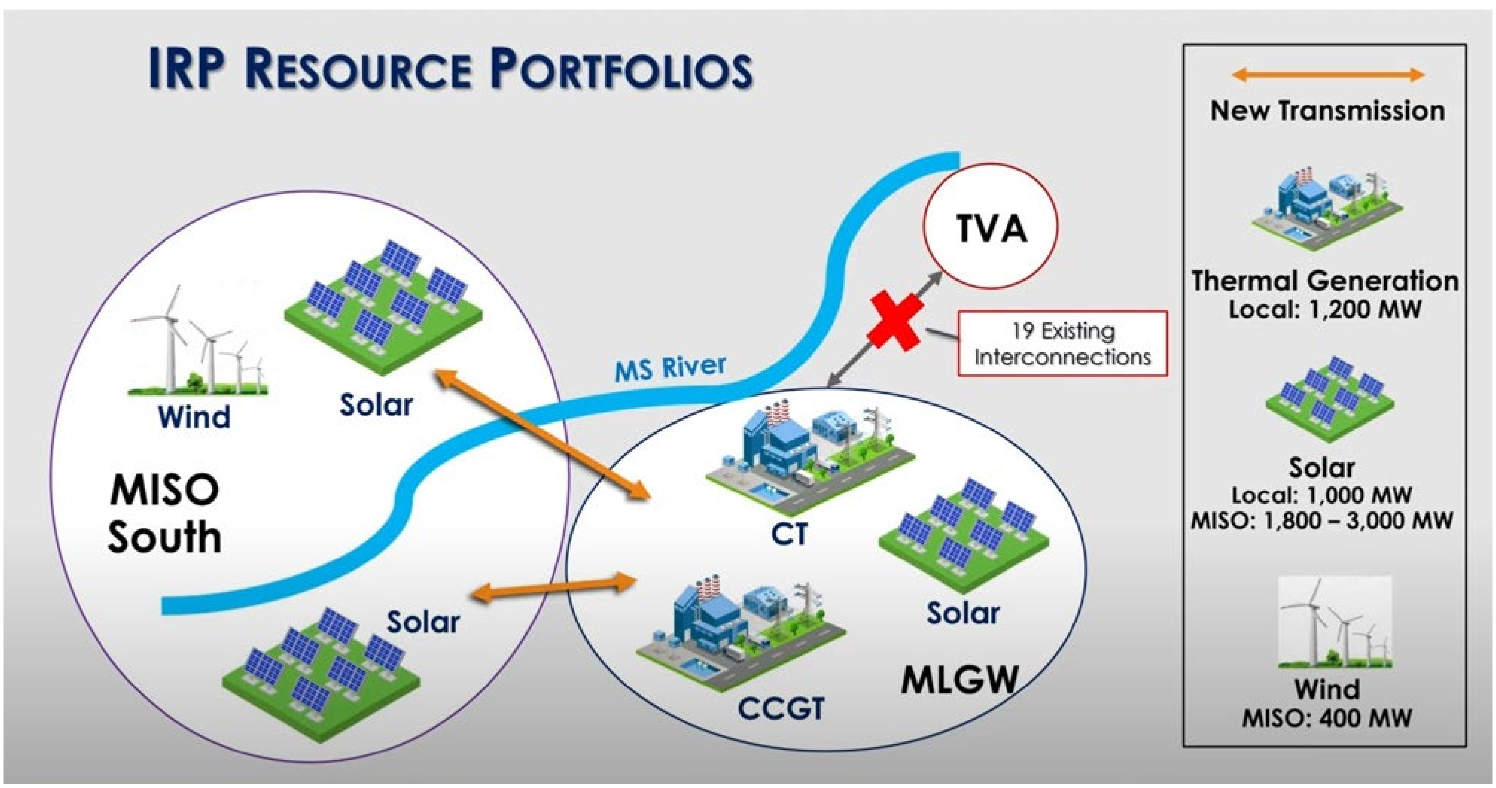
"It seems that moving quickly on this may not be very prudent, but getting our ducks in a row for a longer transition may be something that we should be doing as a system," he said.

GDS said it will finalize its evaluation of the bids and conduct negotiations with a short list of bidders.

MLGW CEO J.T. Young said utility executives will recommend a supplier to its board in August, opening a 30-day public comment period. The commissioners could vote on the issue in September.

The bids, currently confidential, will be made public for the August meeting.

The utility is accepting public comment on the masked bid data at *PowerSupply@MLGW.org*. ■



Options explored under MLGW's IRP include connections to MISO to access renewables and building combined cycle plants and solar near Memphis | *GDS Associates*

CAISO/West News

Calif. Coastal Commission Approves OSW Lease Plans

By Hudson Sangree

The California Coastal Commission took an important step last week to allow the West Coast's first offshore wind lease auctions to proceed later this year, voting to back the federal Bureau of Ocean Energy Management's assessment that lease activities off the coast of Central California are consistent with state and federal laws.

"I'm so excited we've finished this phase and will be moving forward," commission Chair Donne Brownsey said after the unanimous vote Wednesday.

The commission had already approved leasing activities in April for the Humboldt Wind Energy Area (WEA) in Northern California. The latest vote concerned the Morro Bay Wind Energy Area — near the village of Cambria — the second of two WEAs that BOEM plans to auction this fall. Together the areas could generate 4.6 GW, a significant contribution to the state's effort to rely on 100% clean energy by 2045.

While the lease areas in the Morro Bay area are 20 miles offshore in federal waters, the Coastal Commission has broad authority to govern activities within 3 miles of the coast and generally within about 1,000 yards of the high-tide mark on land. Following the auction, BOEM's issuance of leases allows successful bidders to conduct studies in their lease areas, including installing buoys with data collection equipment and geophysical, biological, archaeological and ocean-use surveys. BOEM expects lessees to make up to 873 vessel trips to complete their surveys and site assessments over a three-year period.

"Lease activities have the potential to adversely affect marine resources through seafloor habitat disturbance and increasing turbidity, elevated levels of underwater sound during surveys, increased risk of ship strikes due to increased vessel traffic and incrementally increased entanglement risk due to the placement of buoys," the Coastal Commission said in a *staff report*.

BOEM issued a proposed sale notice for the WEAs last month. (See *BOEM Issues Proposed Sale Notice for Calif. Offshore Wind Areas*.)

The Morro Bay leases will cover about 241,000 acres of ocean in an area home to whales, dolphins, deep-sea corals and sponges, among other species.

The leases do not permit the installation of wind turbines or other infrastructure. Development of the areas will fall under future proceedings by BOEM and the Coastal Commission, requiring approval by both. When development does occur, it will likely include some of the largest floating wind turbines ever built, capable of generating 15 MW each.

"A 15-MW turbine would be expected to have the following approximate dimensions: a hub height of 486 feet, a rotor diameter of 807 feet and a maximum height at the blade tip of 889 feet," the staff report said. "If turbines of this size were installed in the Morro Bay WEA, they would likely have a distance between turbines of 0.917 to 1.22 miles."

Mooring cables, undersea transmission lines and onshore port facilities would be part of the development plans.

"Approximately every 10 years, the entire system would need to be disconnected and towed to shore for repairs, followed by reinstallation," the report said.

The Coastal Commission's decision came with some conditions, including that the lessees' surveys and site assessments minimize impacts to coastal resources, comply with marine wildlife protection measures and avoid contact with rocky outcroppings, seamounts, or deep-sea coral and sponge habitat. Another condition restricts vessel speeds to 10 knots, including during travel from harbors to the survey sites.

Public commenters at the hearing — which noted was surprisingly uncontentious, several of them noted — tended to support commission approval of the lease activities.

"Speaking on behalf of 45 companies, including offshore wind developers and technology firms, we are unified in our support of the Coastal Commission's staff report and its conditions for federal leasing activities in the Morro Bay Wind Energy Area," said Adam Stern, executive director of trade group Offshore Wind California. "Your endorsement of the staff report — similar to your unanimous action on the Humboldt Wind Energy Area in April — would reaffirm the commission's historic commitment to protect California's coastal resources and heritage, while also advancing the state's clean energy and climate goals."

The California Energy Commission is currently re-evaluating its goals for offshore wind development — 3 GW by 2030, and 10 to 15 GW by 2045 — after critics said they were too modest given the state's clean energy needs and should be as high as 18 to 50 GW by 2045. (See *CEC Postpones Vote on Offshore Wind Goals*.) ■

Floating wind turbines off the California coast could surpass current installations in Europe, measuring up to 900 feet tall and generating 15 GW each. | *Principle Power*

PG&E Vows to Reach Net Zero by 2040

By Hudson Sangree

Pacific Gas and Electric said Wednesday it plans to achieve carbon neutrality by 2040 and become "climate positive" by 2050, taking in as much carbon as it produces through carbon capture and other means while continuing to supply natural gas to customers.

"As recent events have made clear, California is not just on the front line for taking action on climate change, we're also at the front line of its destructive effects," CEO Patti Poppe said in a video *announcement*. "We cannot accept that. We can't be content with simply adapting to those harms. We have to slow them down. We need to put that climate machine in reverse and begin undoing the damage."

With its plan, PG&E joins the ranks of large investor-owned utilities that have made climate pledges, including Xcel Energy, which committed in December 2018 to provide its customers with 100% carbon-free energy by 2050, and Arizona Public Service, which did the same in January 2020.

Publicly owned utilities that have made similar commitments include the Sacramento Municipal Utility District, which promised to eliminate all greenhouse gas emissions from its electric generation by 2030. The Los Angeles Department of Water and Power is seeking to rely on 100% renewable power by 2045.

Under Senate Bill 100, California utilities must

PG&E recently commissioned its 182.5 MW Moss Landing Elkhorn Battery System as part of its effort to add more resources to meet the state's clean-energy and reliability goals. | *PG&E*

CAISO/West News

supply retail customers with 100% carbon-free resources by 2045. Other measures require the state to reduce its greenhouse gas emissions to 40% below 1990 levels by 2030 and 80% below 1990 levels by 2050.

PG&E's ambitious plan is short on many details but lays out a broad strategy for meeting its goals.

By 2030, the company said, its generation mix will consist of 70% renewable resources such as wind and solar.

Promoting adoption of electric vehicles is a cornerstone of its carbon-reduction efforts.

"PG&E plans to be the industry's global model by fueling at least 3 million electric vehicles in its service area by 2030 — leading to a cumulative reduction of at least 58 million metric tons of carbon emissions," it said in a news release. The company also wants 2 million EVs to be able to send electricity back to the grid, "allowing EVs to be a cornerstone of energy reliability and resilience efforts." It has begun vehicle-to-grid pilot programs with approval from the California Public Utilities Commission.

Another 48 MMT of carbon reduction could come from building electrification and replacement of gas appliances, it said.

By 2030, PG&E expects renewable natural gas to make up 15% of its gas supply serving residential and commercial customers, and it said it is launching a pilot program to "maximize readiness for hydrogen blending." Converting large industrial and commercial users to a cleaner natural gas supply will cut 2.5 MMT, it said.

"PG&E's vision is to evolve the gas system to be an affordable, safe and reliable net zero energy delivery platform," the utility's news release said. "To make the transition, PG&E expects a diverse mix of resources to be available — from broad electrification to cleaner fuels such as renewable natural gas and hydrogen to nature-based solutions and carbon capture, storage and utilization."

Direct-air carbon capture and underground sequestration will offset greenhouse gas emissions from thermal generation and other sources, PG&E said in its plan.

"With increasing electricity demand from buildings and transportation, California must also substantially invest in thermal generation with clean fuels and/or carbon capture and storage to maintain reliability," it said.

The California PUC would have to approve the programs, including the ratepayer costs at a time of soaring utility bills. PG&E also has announced ambitious plans to bury 10,000 miles of power lines to avoid wildfire ignitions, the massive cost of which must still be determined.

PG&E is planning to close its Diablo Canyon nuclear power plant by 2025, but the utility said it expects to be able to meet its clean energy goals without the plant. The office of Gov. Gavin Newsom recently petitioned the Biden administration to make funds available to keep the plant open to maintain grid reliability while providing a large portion of the state's carbon-free energy. ■

West news from our other channels

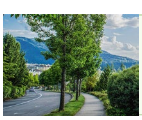

Solar+Storage Project Proposed for Pearl Harbor


CARB Tuning up Advanced Clean Cars II Rules


Critics Tear into CARB Draft Climate Change Plan


Plans Advance for $2B Oregon Renewable Diesel Plant


Wash. Hires Epidemiologist to Study Climate Health Impacts


Seattle-area Communities Auction Carbon Credits to Preserve Forests


Calif., Canada Seek to Increase Cooperation on Climate Issues

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ERCOT News

ERCOT Sets New Record for Peak Demand

Mark Likely Short-lived as Texas' Sweltering Heat Persists

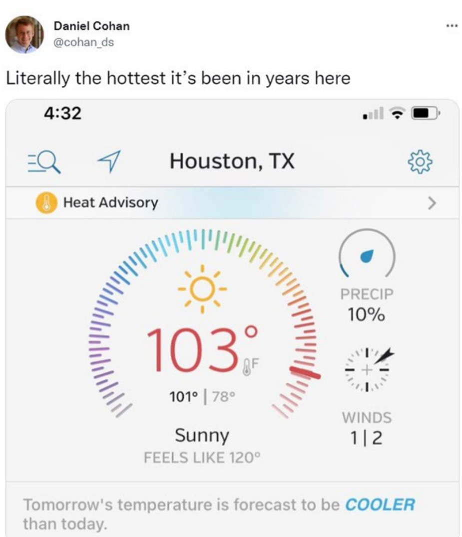
By Tom Kleckner

Sweltering heat — even by Texas standards — led to ERCOT finally setting a new all-time peak demand mark Sunday after several close calls last week.

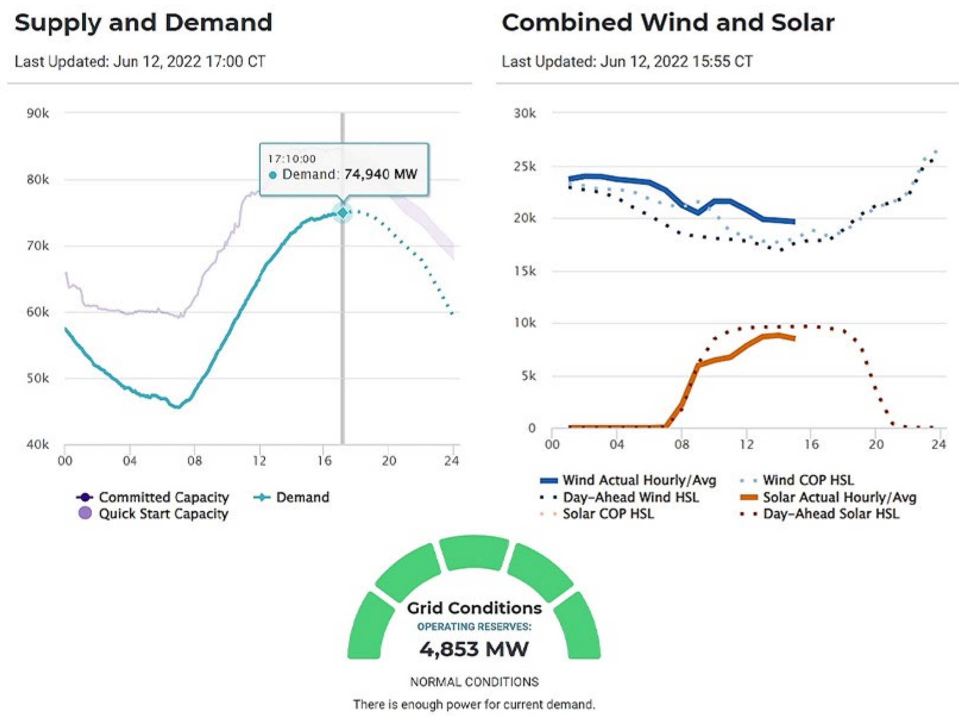
Demand reached 74.9 GW at 5:10 p.m. CT, breaking the previous record of 74.8 GW set in August 2019. Load averaged 74.5 GW during the 4-5 p.m. interval Monday.

That the record came on a weekend, when offices are empty, and during June is an indication of how unusually hot the weather has been in Texas. The state's major cities have set daily records for high temperatures since Friday as an oppressive weather pattern settled over the south central U.S. The National Weather Service issued an excessive heat warning for North Texas on Sunday in anticipation of temperatures above 105 degrees Fahrenheit and heat indexes above 110.

The heat index was as high as 120 F on Sunday afternoon in Houston, where city officials *activated* the city's emergency heat plan and opened cooling centers late last week. Austin also declared a heat emergency and opened cooling centers, where 100-degree temperatures are expected through next week.



The heat index in Houston reached 120 degrees at one point Sunday. | *Daniel Cohan via Twitter*



ERCOT demand teased the 75-GW threshold but still set a record. | *ERCOT*

"Welcome to the final days of spring in Austin," *tweeted* University of Texas energy professor Michael Webber, sharing an image of triple-digit Austin-area temperatures (save for a 99-degree forecast for Wednesday).

Suddenly, ERCOT's "extreme" maximum demand of 81.6 GW this summer doesn't seem so improbable.

ERCOT has yet to issue a formal conservation alert. The grid operator still had nearly 5 GW in operator reserves during Sunday's peak demand. Thermal outages were up slightly to 6.4 GW on Sunday, *according to* Stoic Energy President Doug Lewin.

The Texas grid was operating during the weekend under its third operating condition notice (OCN) since April. The OCN, intended to alert market participants of a possible need for more resources, expired Monday.

ERCOT officials have said they expect "sufficient generation to meet forecasted demand." Indeed, the grid held up, despite *scattered distribution outages* in North Texas, lending a measure of comfort to Texans down on ERCOT since the disastrous February 2021 winter storm.

"Making it through this early heat wave should give some confidence in ERCOT for the rest of the summer," *said* Joshua Daniels, an energy researcher at UT. "The bleeding has stopped; it's time for rehab."

ERCOT again set records for June when demand averaged 73.9 GW and 74.4 GW during afternoon intervals on Friday and Saturday, respectively. Demand exceeded 70 GW at 12:45 p.m. Monday.

ERCOT has benefited from wind and solar energy, though both at times have been curtailed by transmission congestion. The renewable resources were supplying about 28 GW of energy Sunday afternoon, some 3 GW below staff's forecast. The cheap energy helped keep prices under $100/MWh Sunday, with the exception of the Houston load center.

According to a *demand and energy report* posted last week, wind (32.4%) and solar (6.2%) accounted for 38.6% of ERCOT's fuel mix in May. Gas resources provided 32.1% and coal 13.3% of the energy mix. ■

ISO-NE News

ISO-NE Starts its Capacity Accreditation Journey

By Sam Mintz

ISO-NE last week launched its effort to revamp its resource capacity accreditation process, a key fix to the capacity market that has been tied in with discussions around the contentious minimum offer price rule.

In a *presentation* to the NEPOOL Markets Committee on June 7, ISO-NE's Steven Otto laid out the beginnings of the RTO's thinking and offered some early hints as to where it's leaning as it prepares a more detailed proposal in the coming months.

The goals of the project are to boost reliability and maintain cost effectiveness as New England moves toward a decarbonized grid. The RTO's current accreditation process is a mishmash of approaches that the grid operator has acknowledged doesn't do a good enough job reflecting different energy sources' contributions toward resource adequacy and reliability.

One of the key decisions that ISO-NE is thinking through, Otto said, is whether to employ an average or marginal approach to capacity accreditation.

Marginal approaches "set a resource's accredited capacity based on the marginal reliability impact of an incremental change in size," he said. Average approaches, on the other hand, set the accredited capacity based on the average reliability impact of a resource's class.

The RTO is currently leaning toward a marginal approach, Otto said, sometimes also called a Marginal Reliability Impact value.

A Nexamp solar-plus-storage project in Massachusetts | *Nexamp*

The advantages of a marginal approach, according to ISO-NE, are that it sends accurate entry and exit signals to market participants, can incorporate interactions between resource types, and provides the same compensation to resources that provide the same service.

It's far from a settled conversation though: The grid operator is planning a roughly yearlong stakeholder process to hash out the details and decide on a proposal to send to FERC.

The first phase, involving conceptual design and education, is planned to go through October of this year. The RTO will start presenting a detailed design in November and move to finalize that design and produce tariff language by next spring. Stakeholder committee votes are planned for May and June of 2023.

Feedback on capacity accreditation will come both through the stakeholder process and outside of it: The Massachusetts Attorney General's Office, for example, is planning to produce a report with recommendations in the coming weeks. ■

MISO News

OMS-MISO RA Survey Says Supply Deficits Could Top 10 GW by 2027

By Amanda Durish Cook

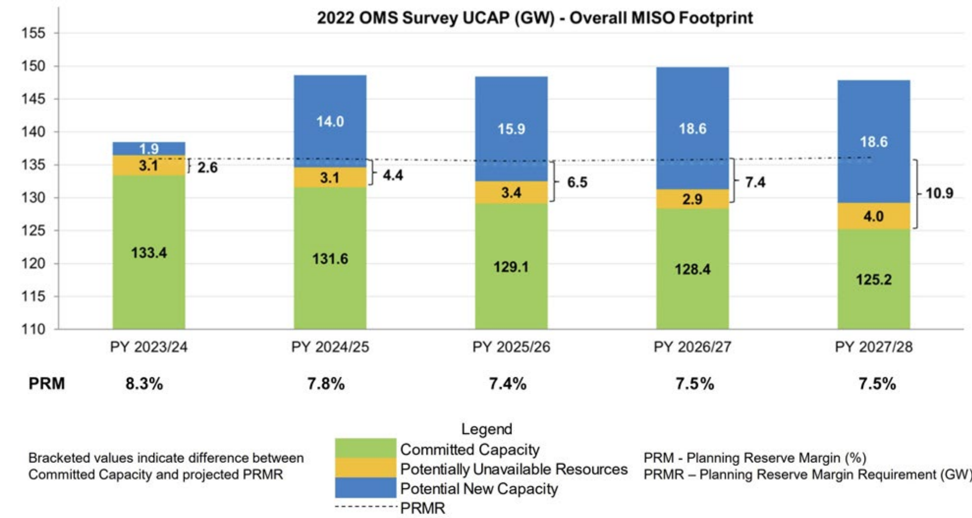
MISO and the Organization of MISO States' 2022 resource adequacy survey again sounded the supply alarm that the RTO rang in early April when it published its 2022/23 capacity auction results.

The survey projects the footprint will have a 2.6-GW capacity deficit below the 2023 planning reserve margin requirement. The shortage would more than double up the 1.2-GW shortfall unearthed in the 2022/23 Planning Resource Auction. (See *MISO's 2022/23 Capacity Auction Lays Bare Shortfalls in Midwest*.) As with the auction results, the survey foresees the shortfalls confined to MISO Midwest.

"Our efforts must be accelerated and reinforced to reliably manage the portfolio transition," MISO Executive Director of Resource Planning Scott Wright said during a special teleconference Friday to discuss the results.

The five-year OMS-MISO survey foresees more bad news on the horizon, as well, with possible capacity deficits that are expected to deepen through 2027. The survey showed MISO could be short 4.4 GW in the 2024/25 planning year, 6.5 GW in 2025/26, 7.4 GW in 2026/27 and nearly 11 GW by 2027/28.

MISO's Local Resource Zone 6, in Indiana and a portion of Kentucky, stands to have the widest capacity deficit in 2023. By the 2027/28 planning year, Zone 7 in Michigan's Lower Peninsula and Zone 8 in Arkansas are the only zones that appear to have a comfortable padding of committed capacity.

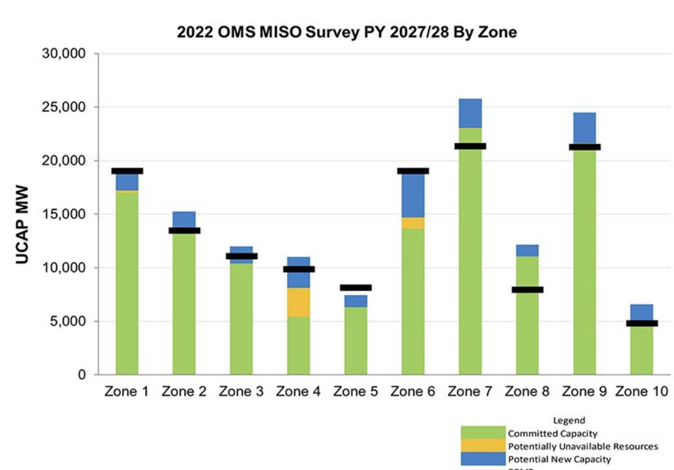


2022 OMS-MISO Survey results | *MISO and OMS*

However, MISO and OMS said much depends on how market resources respond to this year's capacity auction results. If resources act, MISO Midwest could have a 2.4-GW capacity surplus in 2023, they said.

"We think there are a lot of things that could help mitigate the risk and even have a surplus in 2023," Wright said.

The survey put MISO's 2023 demand growth at 1 GW (a 0.8% increase year-over year) as the pandemic recovery finishes. It predicted "modest growth thereafter" at 0.2% per year through 2027. The survey didn't contemplate MISO's new seasonal capacity design and availability-based resource accreditation pending before FERC.



Resource predictions broken down by zone for the 2027-28 planning year | *MISO and OMS*

Last year's survey anticipated the grid operator would have anywhere from 3.4 to 13.9 GW of extra unforced capacity beyond its summer peak planning reserve margin requirement. That supply estimate didn't pan out in the 2022/23 auction, which left MISO Midwest short of its 101.2-GW requirement. The 2021 survey also predicted anywhere from a 3.3-GW shortage to a 13.3-GW surplus through 2025. (See *2021 OMS-MISO Resource Adequacy Survey Shows Less Cause for Concern*.)

MISO predicted it will be increasingly reliant on emergency and non-firm imports going forward. The grid operator said that while those resources are not reflected in the survey, they "have historically been important and available to MISO."

However, if new generation can interconnect, MISO could have a few gigawatts to spare in 2024-2027. MISO and OMS said the impending threat "can be meaningfully mitigated" depending on the tempo of new generation and retirements.

"We have a very active queue process," Wright reminded stakeholders. "I feel like we've had a good track record of adding about 2.5 GW of [unforced capacity] every year."

OMS President and Indiana Utility Regulatory Commissioner Sarah Freeman noted that there are "tons of generation in the queue" waiting to replace retiring resources.

Freeman also said the results are a "very static glimpse" in time, and that MISO's and states' planning processes are dynamic.

But Clean Grid Alliance's Natalie McIntire pointed out that the new transmission capacity MISO is planning under its long-range transmission portfolio is still years away. She said the new lines are needed in order to interconnect new generation.

Freeman opened the floor to suggestions on how to improve next year's survey structure.

"It's only as accurate as the questions we have on it," she said. ■

MISO News

MISO Bolstering Generation Retirement Studies amid Capacity Shortage

By Amanda Durish Cook

As it stares down its footprint's supply crunch, MISO is proposing to revise its generator retirement studies to include more notice, relaxed confidentiality rules, and stiffer adherence to local reliability requirements.

However, staff were firm during the Planning Subcommittee's meeting June 7 that the changes will not add resource adequacy considerations to MISO's existing study process.

The grid operator announced last month that it was considering bulking up the studies under its Attachment Y process that determine whether retiring generation needs to stay online longer under a system support resource agreement. (See *Capacity Shortage Prompts MISO to Consider Broadened Retirement Studies*.) Presently, the retirement studies focus solely on the transmission system's reliability, not resource adequacy; MISO does not have the jurisdictional authority to extend generators' operational lives because of resource adequacy concerns.

The RTO's Sydney Yeadon said staff seek to "mitigate some challenges" with escalating retirement notices coming from its membership.

She said MISO will impose a one-year notice requirement on retiring generation before MISO begins Attachment Y studies, a six-month extension of current practices.

"More time is needed to conduct more in-depth studies," Yeadon said. She said the year-long warning will give staff "greater visibility of the near-term resource mix."

Anticipating more generation retirements, MISO also proposed to conduct retirement studies in batches on a quarterly basis instead of when the requests are received.

MISO's Andy Witmeier said a quarterly kickoff of retirement studies will help staff better manage their workload. He said the RTO is never certain of how many retirement or suspension requests it will receive at any given time.

"We need more time in order to do the analysis," he said.

The doubled notice time and quarterly cadence will allow MISO to conduct stability studies on a more frequent basis. Yeadon said the extra studies are necessary as the amount of retiring baseload generation picks up.

The grid operator will also begin sharing the systemwide number and megawatt value of retirement requests, Yeadon said. She said MISO "obviously" won't share the details of individual retirement requests.

Attachment Y notices are currently confidential unless an owner waives recission rights and places a unit directly into retirement, the generator doesn't return to service when the recission period ends, or MISO evaluates the resource as a possible system support resource.

The RTO also plans to alter the customary mitigation practices used in the retirement study process' steady state analyses. Staff allows load shed as a mitigation option when voltage and thermal violations are uncovered but going forward, staff wants to lessen wean reliance on load shed.

Stakeholders debated whether MISO's proposed limits on load-shed mitigation amount a change rooted in resource adequacy concerns.

"We're just trying to ensure reliability with the practices we have," Yeadon said.

"That's going to get litigated, I'm sure," replied Customized Energy Solutions' David Sapper, representing MISO load-serving entities.

Witmeier said it's not MISO's purview to dictate when generation retires and that the grid operator is merely focusing on local reliability requirements.

"The enhancements that we're proposing here are [an] improvement to the process," he said.

DTE Energy's coal-fired Belle River Power Plant is slated for closure at the end of 2028. | *DTE Energy*

MISO News

Stakeholders asked whether MISO is considering further changes to its retirement studies to hang onto the capacity it has.

"I feel like there's been a lot of stakeholder discussion around this, and I wonder if MISO internally has been discussing some kind of joint forum on it," Clean Grid Alliance's Natalie McIntire said.

Witmeier said no such workshop is on the horizon for now. He said the stakeholder-led Resource Adequacy Subcommittee could pursue future discussions on Attachment Y process, but it hasn't yet.

MISO considers the issue a planning matter, though stakeholders have called for improving the Attachment Y process, given the topic's implications to the footprint's resource adequacy.

"We don't want to slow down the improvements that we see could be done now," Witmeier said.

"This is a step in the right direction, but it doesn't go far enough," Prairie Power's Karl Kohlrus said of the study process changes.

Kohlrus said he's concerned that staff isn't reflecting all future baseload retirements in their transmission-planning models. He said MISO hasn't yet accounted for all announced baseload retirements or impacts stemming from Illinois' Climate and Equitable Jobs Act.

"I'm concerned that there's no place for MISO to do accurate modeling … It's kind of scary as a planner that you're studying a future that won't exist," he said.

Staff said they will update planning models with the latest retirements later this year.

MISO Independent Market Monitor's Michael Chiasson also said the RTO's retirement and suspension practices have a loophole where a unit can remain on an extended outage for years without being pressured to designate its unit as either suspended or retired. Chiasson said resource owners who don't want to replace their capacity are essentially allowed to "tie up interconnection" points with nonoperational units.

"I see a couple of examples here and there, not huge amounts. … It's not really widespread at this point," Chiasson added. But he said as MISO reassesses its current retirement study practices, "it's a good time" to also address the gap.

Coal Retirements Mounting

Coal advocate America's Power said it has tallied announced coal retirements in MISO at 19.3 GW in the 2022-2027 timeframe and 27.3 GW by 2030. The group said if utility announcements pan out, 35% of MISO's current coal fleet will retire within the next five years, with half of the fleet idled by 2030.

America's Power said its estimates don't factor in coal retirements that might be spurred by reinvigorated federal regulations. The group said those regulations could lead to more than 30 GW of MISO's existing coal capacity installing selective catalytic reduction and/or flue gas desulfurization.

"We are concerned that these facts about future coal retirements might not have received the attention they deserve," the group said in a late April memo circulated within MISO.

America's Power also said the coal generation that will retire over the next five years supplied an annual average of 16% of MISO's energy during 2019-2021 with an average capacity factor of slightly more than 50%. ■

MISO News

MISO Stakeholders Protest RTO's Order 2222 Implementation Timeline

Utilities, TOs Supportive of 2029 Effective Date

By Michael Brooks

Multiple stakeholder groups, including state regulators, protested MISO's FERC Order 2222 compliance filing on June 6, with many expressing indignation with the RTO's request to delay implementation until nearly 2030 (ER22-1640).

MISO filed its *proposal* April 14, with the commission granting its request to extend the standard 21-day comment period until June 6. In a letter accompanying the proposed tariff changes, MISO said its proposed Oct. 1, 2029, effective date is necessary because it will take "several years of technology development to enable DERA [distributed energy resource aggregation] participation in wholesale markets."

Approved in September 2020, *Order 2222* directed all FERC-jurisdictional RTOs and ISOs to revise their tariffs to allow DERAs to provide any services they are technically capable of in their wholesale markets. (See *FERC Opens RTO Markets to DER Aggregation*.)

The commission had set a compliance filing deadline of nine months after the order's publication in the *Federal Register* (about June 2021), but several RTOs quickly requested more time, with PJM and ISO-NE, for example, filing on Feb. 2 (2/2/22). Over that time, officials repeatedly told stakeholders how complex and time consuming the work was. (See "Order 2222 Compliance Work 'Highly Complex,'" *SPP Markets and Operations Policy Committee Briefs: April 11-12, 2022*.)

FERC gave RTOs and ISOs flexibility in proposing a deadline for implementation. MISO's is the longest among the grid operators. It proposes making registration available beginning Oct. 1, 2029, with participation in energy and ancillary service markets offered by March 1, 2030. The RTO told FERC that it first needs to complete its market systems enhancements (MSE) project — a long-in-the-works replacement of its market platform expected by the end of 2024 — before it has the technological capability to comply with the order.

"The completion of the MSE project, including the replacement of MISO's legacy systems and software with the integration of new market engines into MISO's systems, is a necessary prerequisite to development of the software and systems needed to incorporate DERA in the [RTO]'s markets," it said.

MISO also said it wants to prioritize work

| ChargePoint

MISO News

on its much-delayed Multiple Configuration Resources (MCR) initiative, which is intended to improve modeling of different combinations combined cycle unit types. When completed alongside the MSE project, MCR "is expected to provide reliability benefits by providing operational flexibility needed to manage the MISO region's increased reliance on intermittent resources, such as wind and solar, to meet the region's baseload demand needs," the RTO told FERC.

"While MISO recognizes the benefits of promoting distributed energy resource participation in its wholesale markets through the addition of distributed energy resource aggregations, the benefits of these aggregations are unknown and relatively limited by the existing retail regulatory construct in many of the states in the MISO region."

Environmentalists, consumer advocates and state regulators said the 2029 date was unacceptable.

The Organization of MISO States said it "recognizes the importance and benefits of MSE and MCR but questions MISO's purported inability to pursue a parallel path for the implementation of MCR and Order 2222. MISO does not provide sufficient evidence why parallel implementation is not possible outside of a generic description that pursuing these changes simultaneously would increase the risks to reliably implement these products."

OMS noted that PJM proposed a 2026 effective date, after implementing its new market clearing engine and Enhanced Combined Cycle model in 2025. "From the testimony MISO provided, it is unclear why MISO cannot do the same."

Filing jointly, groups including the Natural Resources Defense Council, Sierra Club and the Union of Concerned Scientists noted that MISO's proposed date would push back DERA participation to "nearly 10 years after the commission issued Order No. 2222 and nearly 14 years from the commission's publication of the Notice of Proposed Rulemaking that led to Order No. 2222."

"In essence, MISO is arguing that its markets must remain unjust and unreasonable and unduly discriminatory with regard to DERAs for nearly a decade while it sorts out technology issues that it ought to have been aware of and planning for since well before the commission issued Order No. 2222," the groups said.

Advanced Energy Management Alliance argued that "MISO has not provided a reasonable explanation for such an extended implementation timeline given the rapidly evolving needs of consumers and the overall electric grid." Similarly, Advanced Energy Economy and the Solar Energy Industries Association jointly argued that "by choosing to implement other initiatives over compliance with Order No. 2222, MISO is choosing to keep barriers to participation of DER aggregations in place nearly a decade after the commission first sought to remove them."

Utility and TO Support

In contrast, MISO member utilities were largely supportive of the timeline, agreeing with the RTO on the complexity of the work.

"In permitting thousands of new generation resources to access wholesale markets, Order No. 2222 requires enormous technical planning to ensure that local distribution and transmission systems are upgraded to accommodate the new resources; that market rules, IT systems and data requirements are sufficient to allow coordination of these new resources without jeopardizing safety, reliability or cybersecurity; and preservation of appropriate roles and authorities for both state regulators and local distribution system owners," Consumers Energy said.

"This is no small task, as MISO's filing makes clear — particularly when implementation must take place alongside efforts to address other critical priorities of RTOs and ISOs, including reliability, resiliency, customer affordability and a seismic shift in the electric grid's underlying resource mix."

Alliant Energy said it "generally supports the changes as filed, recognizing that there is still much to learn and understand regarding the operation and impact of DER aggregations in MISO's markets." Ameren said it "appreciates MISO's independent assessment of its current capabilities and supports MISO's determination that the identified software improvements need to be completed before other initiatives can be launched."

While noting "potential revisions ... are needed," MISO transmission owners also supported the effective date.

"MISO has undertaken multiple initiatives ... to address the unique and complex challenges to electric system reliability in the MISO region," they said. "Completion of these initiatives is expected to bring immediate and quantifiable reliability and economic benefits to the MISO region. At the same time ... only three states in the MISO footprint currently permit retail demand resource aggregation, which could significantly limit participation of such aggregations in MISO's markets." ■

MISO News

Clean Grid Asks MISO for Penalty-free IC Exits

By Amanda Durish Cook

The Clean Grid Alliance asked MISO on June 6 to consider penalty-fee withdraws for advanced-stage interconnection projects that are saddled with expensive network upgrade costs from SPP's delayed affected system study (AFS) results.

A month after requesting relief for late-stage projects held in limbo until they receive AFS results from SPP, CGA's Rhonda Peters returned to MISO's Interconnection Process Working Group (IPWG) to propose a penalty-free withdrawal for projects rendered infeasible by SPP-identified upgrade costs. (See *CGA Requests MISO Help for Late-stage Interconnection Projects*.)

MISO and SPP have rolled out a new "first ready, first served" interconnection queue priority for generation projects that affect the seams through studies and cost assignments for network upgrades. The new order replaced the grid operators' previous practice of studying projects that lined up for the queue first. (See *FERC OKs New Queue Priority for MISO, SPP Seams Studies*.)

In MISO, the new priority bypassed projects that entered the queue in 2018 and 2019. The RTO said those project cycles are destined for generator interconnection agreements (GIA) before the changes take effect.

Peters said some late-stage projects that entered the queue with the 2018 and 2019 cycles still don't have "complete, accurate or available" network upgrade costs from SPP's affected system studies.

She said the uncertainty has jeopardized the projects' financing and power purchase agreements. "The risk factor is too high," she said.

Peters said MISO should consider allowing penalty-free withdrawals from the queue when late AFS results unexpectedly increase affected system costs. That would allow developers to depart the queue without forfeiting their milestone fees, she said. Peters said MISO could allow projects to interconnect beyond the original seven-year deadlines to reach commercial operation or it could provide nonbinding estimates of likely upgrade costs to aid the developers' decision making.

Peters said developers of late-stage generation projects have already committed significant capital but might be forced to withdraw when AFS costs "are so high that they could completely change the financial viability of the projects."

"Advanced stage projects only withdraw if forced to due to circumstances beyond their control, such as unexpected or new network upgrades," she said. "The financial commitment to reach GIA is significant, even without consideration of milestones. … The interconnection customer wants to reach its commercial operation date. Withdrawals occur only when there is no other course of action."

MISO's Ryan Westphal said allowing penalty-free withdrawals could "potentially harm other customers." The RTO usually keeps milestone fees when interconnection customers leave the queue to minimize the costs of network upgrades on lower-queued projects.

Stakeholders pointed out that AFS results can often double an interconnection customer's network upgrade costs.

| © RTO Insider LLC

Westphal asked whether other stakeholders would be comfortable with penalty-free exits from the queue.

Invenergy's Sophia Dossin said while her company has projects in the 2018-19 cycles of the queue, it also has projects that entered in 2020 and later. She said Invenergy is poised to be affected on both sided of the issue and is comfortable with penalty-free exits.

"I would say a lot of customers that are being impacted by the 2018-19 delays will also be impacted by the penalty-free withdrawals. … If there were a Venn diagram, there would be substantial overlap." Dossin said. "This already is creating a lot of financial issues today."

Dossin added that no project's financing partner wants the risk of a "multimillion dollar question mark" on projects waiting on AFS upgrades.

"We're not in the business of playing games. We'd rather see our projects online," National Grid Renewables' Rafik Halim said. He added that he didn't think developers would view the option as an unconditional "greenlight" to remove generation projects from the queue.

"We shouldn't be signing a blank check as we sign our GIAs," Halim argued.

Peters said MISO could institute "rigid" criteria, such as a minimum cost threshold increase for network upgrades.

Westphal said MISO wouldn't likely move forward with a penalty waiver unless all stakeholders are on board.

"In our opinion … this seems like a mechanism to allow harm and financial impact to other customers," he said.

Staff also pointed out that interconnection customers should already be estimating a spectrum of AFS costs. They said extending operation deadlines for the 2018-19 project cycles might simply perpetuate uncertainty and affect lower-queued generation projects.

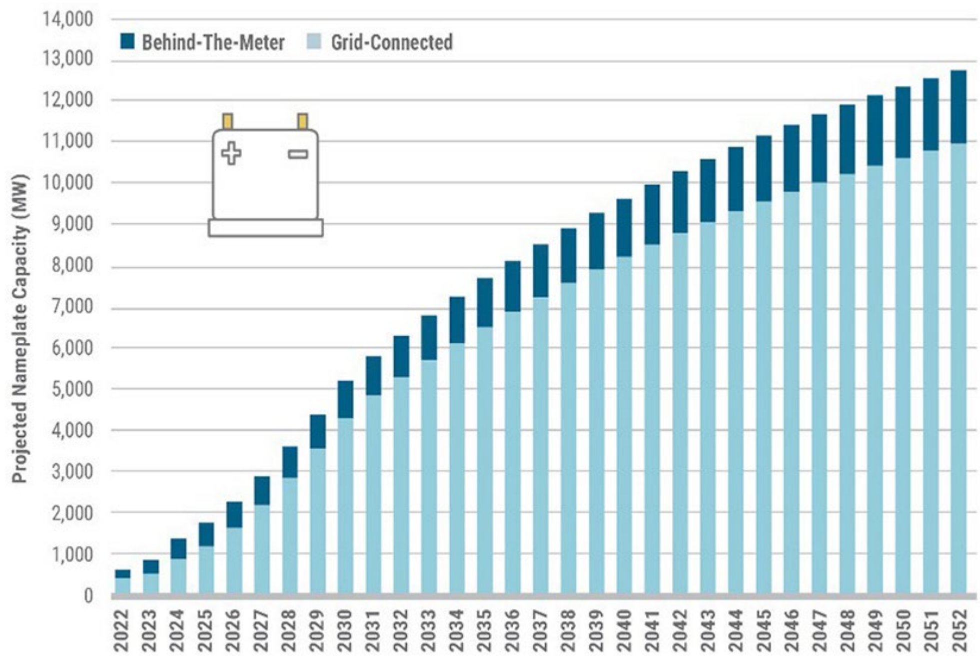
Peters argued that it would "make a huge difference" to financiers if bookends for upgrade cost changes came from MISO instead of the interconnection customers themselves.

MISO is set to again discuss the fate of the 2018-19 interconnection projects during the IPWG's August meeting. ■

NYISO News

NYISO 2022 Power Trends Report: Reliable Clean Energy Needed Quickly

By Michael Kuser



Projected energy storage nameplate capacity. New rules will encourage battery storage resources, which will help balance the variable nature of solar and wind power. | *NYISO*

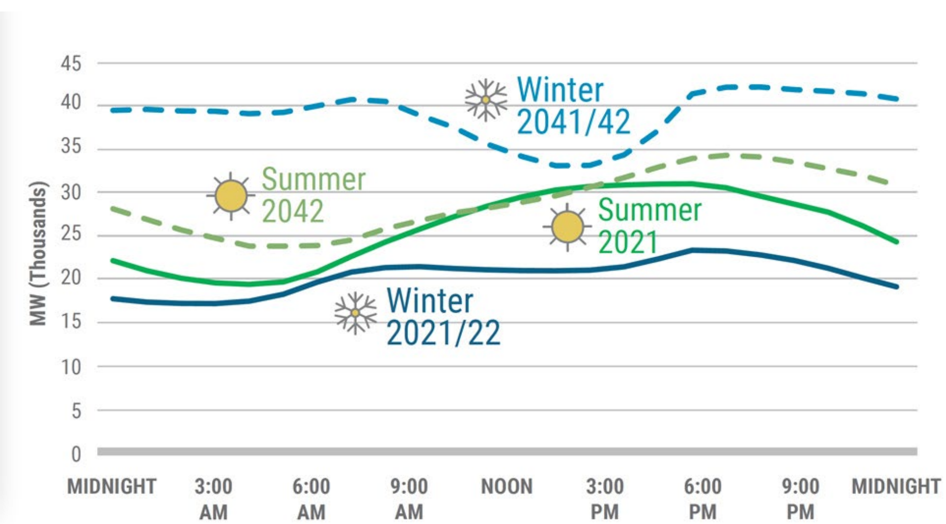
NYISO continues to adapt its wholesale electricity markets and grid planning processes to accommodate a wave of widely distributed renewable resources more dependent on weather than traditional generation, according to the ISO's annual Power Trends *report* issued Wednesday.

"The introduction of a lot of new resources and the planned exit of some high-emitting resources that we've relied on for quite some time has resulted in an increasingly dynamic, decentralized grid, which means it's much more complicated to be able to manage and predict how the core functions are going to be satisfied," CEO Rich Dewey said in a press briefing. "A lot of our focus is making sure that we've got the tools and capabilities to maintain the necessary level of reliability as we move through that transition."

Reliability margins are shrinking as generators needed for reliability are planning to retire, and electrification of space heating will likely flip the peak load from summer to winter in the mid-2030s, according to the report, subtitled "The Path to a Reliable, Greener Grid for New York." Meanwhile, delays in building new supply and transmission, higher-than-expected demand, and extreme weather could threaten reliability and resilience in the future, the report said.

A successful transition of the electric system requires replacing the reliability attributes of existing fossil fuel generation with clean resources with similar capabilities, the report said. New transmission is being built, but more investment is necessary to support the delivery of offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest.

"We at NYISO have been firm advocates for the need for new transmission for several years now, and we're happy to report that that New York state, not only the New York ISO, but also some of our state partners — the Public Service Commission and the New York Power Authority — are making meaningful progress in the development of new transmission that will be critically important to help move power from the upstate region," Dewey said.



2021 New York Control Area (NYCA) Bulk Electric System 2021 Actual and 2042 Forecasted Winter/Summer Load Shapes | *NYISO*

New York's Climate Leadership and Community Protection Act (CLCPA) requires that 70% of the state's energy come from renewable resources by 2030 and that its grid be 100% net-zero emissions by 2040.

FERC in May approved three changes to NYISO's capacity market that were spurred by the CLCPA, such as excluding new policy-driven resources from its buyer-side market power mitigation (BSM) rules, which will eliminate offer floors for wind, solar, storage, hydroelectric, geothermal, fuel cells that do not use fossil fuel, demand response and other qualifying resources under the law. (See *FERC OKs NYISO Capacity Market Changes Stemming from NY Climate Law*.)

Hourly load profiles are also changing because of the growing impacts of behind-the-meter solar, EV charging, climate change and post-COVID-19 shifts in the occupancy rates of homes and businesses, the report said.

The ISO's *announcement* for the report also includes a *datasheet* of key takeaways. ■

NYISO News

DR Provider Seeks NYISO Approval for Small Customer Aggregations

By Michael Kuser

California-based demand response provider OhmConnect is seeking NYISO's approval to this summer begin enrolling small customer aggregations (SCAs) as special case resources (SCRs) in the ISO's wholesale capacity market.

"All residences will be Con Ed customers located in NYISO Zones H, I or J," John Anderson, director of energy markets at OhmConnect, said June 7 in presenting the SCA *proposal* to the ISO's Installed Capacity/Market Issues/Price Responsive Load Working Group.

OhmConnect has enrolled over 250,000 residential customers into its various programs in CAISO, ERCOT and Australia.

Most SCA proposals that come before the working group are trying to address the problem of a lack of available metering data and to win approval for alternative metering methodologies, but OhmConnect's New York customers all have advanced metering infrastructure or smart meters, and the aggregator obtains the customer data directly from Con Edison through their Share My Data platform, Anderson said.

"The challenge we face is instead a technical one in the NYISO demand response information system (DRIS), and simply stated, the system as currently configured cannot accommodate customers whose average coincident loads are smaller than 1 kW," Anderson said.

OhmConnect has in fact already signed up several thousand residential customers, approximately half of whom are already participating in the ICAP program, he said.

"These customers are sufficiently large that we were able to enroll them directly in the program, and our focus here today with the SCA proposal is on the remaining half of our customer base that was too small to enroll directly due to the current DRIS design," Anderson said.

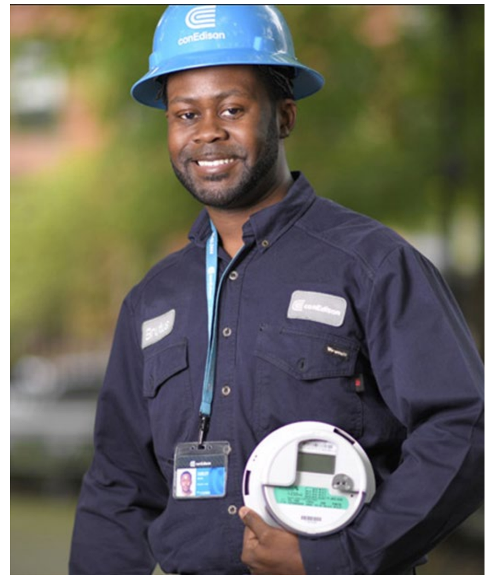
An SCA proposal must be approved by at least four of the chairs and vice chairs of the NYISO Management Committee and Business Issues Committee, and the chairs of the ICAP and Price Responsive Load Working Groups. The approvals were to be requested from the applicable approvers by email after the meeting, said Ethan Avallone, NYISO distributed resources operations manager.

"This metering meets the NYISO's expectations for the SCR program participation, and the ISO supports enrolling these resources as a small customer aggregation in the SCR program," Avallone said.

The SCAs will consist of the curtailment from residential customers who will participate in the ICAP-SCR program, and OhmConnect intends for these customers to participate in the 2022 Summer Capability Period as early as July and is requesting multiple SCAs for each zone to accommodate future anticipated customer growth, Anderson said. NYISO rules prohibit any change to an SCA within a given capability period.

"When a customer enrolls and authorizes us access to their data, we can use the data to directly calculate performance of the resources in an SCA. We do not need to infer that performance, but can measure it directly," Anderson said.

Asked about the effect of customers opting out of a DR event, Curtis Tongue, OhmConnect co-founder and chief strategy officer, said, "We typically see opt-out rates from our customers at about 1% or less per event, so in practice it ends up being a relatively negligible impact."


| Con Edison

Several market participants asked how NYISO will ensure that any additional SCA proposals, whether to serve different load zones or not, would employ the same methodology being approved in this process.

If the aggregator has the first proposal approved in one methodology and comes the next month with another proposal, "we would validate that they are doing the same exact methodology," said Steven Gill, technical specialist on the ISO's distributed resources operations team. "We have correspondence back and forth with [OhmConnect] that it's the same exact methodology and load reduction plan, and the same exact intentions and way they're going to deliver megawatts to the grid." ■

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PJM PC/TEAC Briefs

Planning Committee

Reserve Requirement Study Assumptions Approved

The PJM Planning Committee last week unanimously endorsed *study assumptions* developed in the Resource Adequacy Analysis Subcommittee (RAAS) for the RTO's 2022 Reserve Requirement Study (RRS).

The assumptions, which are similar to those used in the 2021 RRS study, will be used to reset the installed reserve margin (IRM) and forecast pool requirement (FPR) for delivery years 2023/24, 2024/25 and 2025/26, as well as to set the initial IRM and FPR for 2026/27, PJM's Jason Quevada *told* the committee.

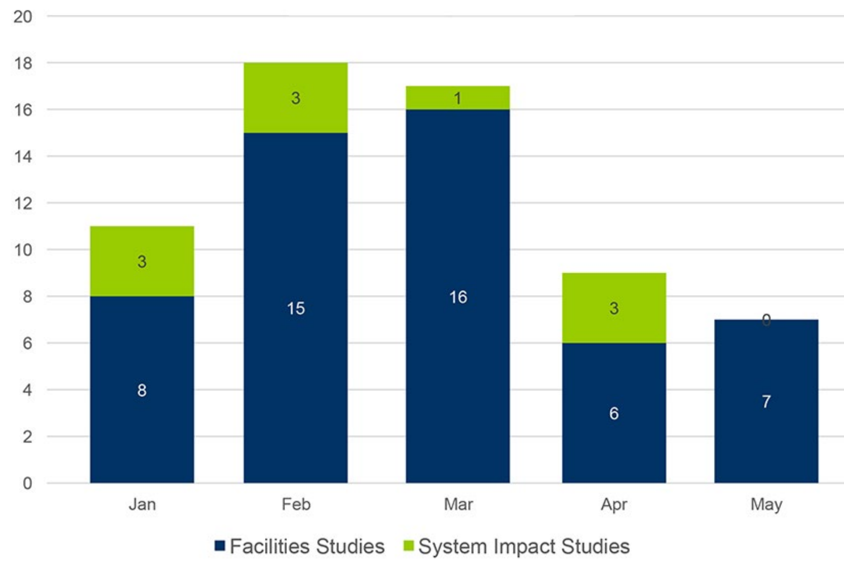
PJM uses each generating unit's capacity, forced outage rate and planned maintenance outages to develop a cumulative capacity outage probability table for each week of the year, except the winter peak week. For the winter peak, PJM uses historical RTO-aggregate outage data from delivery years 2007/08 through 2021/22.

The new assumptions reflect FERC's approval in August of PJM's effective load-carrying capability (ELCC) method for determining capacity values for variable, limited-duration and combination resources (*ER21-2043*). (See *FERC Accepts PJM ELCC Tariff Revisions*.)

PJM told FERC that the ELCC construct recognized the "diminishing returns associated with greater levels of deployment for most ELCC resource types," ensuring that the RTO doesn't become overdependent on a single resource with "inherent limitations."

Wind, solar, hydro and landfill gas variable resources and storage resources will be excluded from the 2022 calculations.

PJM will present the final RRS report to the RAAS and PC in September and will seek members' approval in October. Posting of the final values is expected in February.



Studies issued by PJM in January-May 2022 | *PJM*

Interconnection Process Subcommittee Charter OK'd

Members unanimously approved the draft *charter* of the Interconnection Process Subcommittee, which is being formed to continue work on interconnection process improvements following the sunsetting of the *Interconnection Process Reform Task Force* (IPRTF).

Stakeholders approved a new interconnection queue process and a related transition plan developed by the task force in April. (See *PJM Stakeholders Endorse New Interconnection Process*.) The proposed rules will be filed with FERC by June 16.

Also at the PC meeting, Jason Shoemaker, manager of interconnection projects, provided an *update* on the RTO's efforts to reduce the interconnection queue backlog.

Shoemaker said queues AG2 and AH1 will continue to be delayed, and AH2 and AI1 are also expected to be delayed. As a result, PJM is deferring project modification requests in those queues. PJM's backlog priorities are AD2 and prior queues (65 studies); backlogged system impact studies (about 190); and queues AE1 through AG1 (about 800), he said.

Response to DOE Notice of Inquiry

PJM's Pauline Foley briefed the committee on the RTO's plan to respond to the Department of Energy Grid Deployment Office's May *Notice of Inquiry* and request for information on how it should implement the "anchor tenant" and revolving loan programs under its *Transmission Facilitation Program* (TFP). The TFP is intended to aid the construction of grid infrastructure that improves reliability and resilience or increases interregional transfers. (See *DOE Seeks Input on Tx Loan, 'Anchor Tenant' Programs*.)

The program, authorized under the Infrastructure Investment and Jobs Act (IIJA), allows DOE to purchase up to 50% of the proposed transmission capacity of an eligible transmis-

PJM News

sion line for up to 40 years. It can also make loans for the costs of carrying out an eligible project: new lines of at least 1,000 MW (500 MW for projects in an existing transmission corridor).

The IIJA also authorized DOE to enter into public-private partnerships to advance an eligible project in a National Interest Electric Transmission corridor or that is necessary to accommodate an increase in transmission demand across more than one state or transmission planning region. DOE is authorized to borrow up to $2.5 billion from the U.S. Treasury at any one time.

Responses to DOE were due Monday.

Transmission Expansion Advisory Committee

Generation Deactivation Update

PJM reported that it completed reliability analyses and identified no violations for the following *generation deactivations*:

- Morgantown combustion turbines 1 and 2 (32 MW) in the PEPCO transmission zone (Oct. 1);
- Carbon Limestone landfill (19.3 MW) in the American Transmission Systems Inc. (ATSI) zone (July 31); and
- Cape May County landfill (0.6 MW) in the Atlantic City Electric zone (Aug. 5).

Members also heard second reads on proposed solutions to:

- an N-1 thermal violation on the 345-kV Beaver-Hayes line resulting from the planned retirement of Sammis 5, 6 and 7 (1,504 MW) in the ATSI zone on June 1, 2023. The recommended solution includes replacing four 345-kV disconnect switches with 3000A disconnect switches; replacement of substation conductors; upgrades of transformer protection relays; and relay settings changes. The estimated cost is $2.1 million.
- the March 31 deactivation of Avon Lake 9 and 10 (648 MW) in ATSI. The plan includes removing five 138-kV bus tie lines and one 345-kV bus tie line from the Avon Lake Substation; adjusting relay settings; and installing new fiber between the 345-kV and 138-kV yards to re-establish relay protection. The project, expected to be completed by April 28, 2023, has an estimated cost of $2.5 million.

Supplemental Projects

Members heard presentations on the following supplemental projects:

- FirstEnergy *outlined* a 230-kV service request for a 30-MW load near the 230-kV line Doubs-Monocacy, with a requested in-service date of November 2022 (Need # APS-2020-012).
- Dominion Energy *presented* more than a dozen supplemental requests, including new substations and additional distribution transformers to serve data centers and other sources of load growth.

NJ Offshore Wind SAA

Remaining reliability studies will be completed in July and August for selected scenarios in the 2021 State Agreement Approach proposal window to support New Jersey's offshore wind projects, PJM's Jonathan Kern *told* members. Scenario development and initial reliability studies are expected to be completed this month.

PJM is considering about 26 point-of-interconnection scenarios.

The New Jersey Board of Public Utilities is reviewing comments that were submitted in its OSW transmission docket (*QO20100630*), including responses to questions posted following four stakeholder meetings the agency held to collect feedback on the evaluation of the transmission proposals. (See *NJ Seeks Efficiency, Savings in OSW Transmission Process*.)

60-day Proposal Window Opened

PJM opened a 60-day window June 7 to receive proposals to address reliability and market efficiency needs on the 345-kV Crete-St. John, Crete-E. Frankfort, University Park N-Olive and Stillwell-Dumont lines.

Multi-Driver Proposal Window 1 will reflect the removal of queue project U3-021/AB2-096 and the inclusion of project AB1-089, PJM's Sami Abdulsalam *told* members. PJM will evaluate the proposals in coordination with MISO. The window closes Aug. 8.

PJM noted an overlap in flowgates from the new window and 2021 Proposal Window 2 and said entities wanting to modify their 2021 proposals should submit new entries in the new window. Entities wanting to withdraw proposals from consideration must notify PJM to avoid future billing.

Abdulsalam said PJM is planning to open a proposal window for the 2022 Regional Transmission Expansion Plan between the last week of June and first week of July. PJM posted the latest preliminary models on May 23 and is reviewing FERC Form 715 analysis results from transmission owners while working on N-1-1 and load deliverability analyses.

— Rich Heidorn Jr.

PJM Market Implementation Committee Briefs

Variable Environmental Costs and Credits

PJM gave a second first read of a *proposal* to update 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 committee will be asked to endorse the package, which includes changes to Manual 15 and Schedule 2 of the Operating Agreement, at its next meeting.

Market Suspension

PJM's Stefan Starkov gave a *second first read* of the revised PJM/Independent Market Monitor package of changes to the treatment of long-term market suspensions. The package, which is intended to address a gap in tariff language regarding how to settle the real-time market if prices can't be determined, was revised to reflect feedback received at the May MIC meeting.

In September, the Markets and Reliability Committee delayed a vote on rule changes after representatives from Calpine and Vistra made a motion to defer pending further discussions at the MIC. (See "Market Suspension Vote Delayed," *PJM MRC Briefs: Sept. 29, 2021*.)

Calpine said the proposal did not adequately address market suspensions lasting a week or longer, and that it was concerned with compensating generators for an extended period based only on their cost-based offers, which are computed solely on short-run marginal costs.

The original proposal would have had different rules for outages of more and less than six hours. Outages less than or equal to six hours would substitute the missing hours with available day-ahead or real-time LMPs or the average of adjacent hours. For outages of more than six hours, LMPs would be set at $0/MWh, with make-whole payments at the lesser of dispatched megawatts or actual megawatts using cost-based offers.

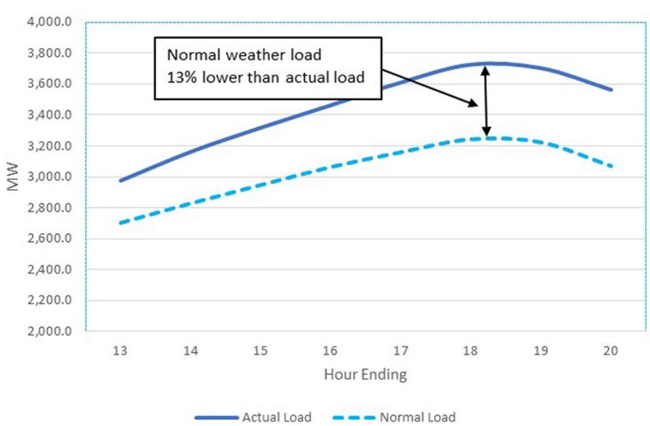
The revised proposal would use available DA or RT LMPs or the average of adjacent hours for all outages less than or equal to 24 hours. Pricing for outages longer than 24 hours would be set using a long-term market clearing mechanism incorporating the aggregate supply curve.

The curve would be based on hourly supply-demand intersections constructed from available offers (including available resources not running) and actual generation megawatts as a proxy for demand. Constraints would be ignored. Energy and ancillary services would continue to be calculated at five-minute intervals.

The committee will be asked to endorse the package at its next meeting.

DR/PRD Compliance for Weather-sensitive Load

Sharon Midgley, representing Exelon and Baltimore Gas and Electric (BGE), presented a first read of a *problem statement* and *issue charge* to consider an alternative demand response/price-responsive demand (PRD) compliance construct for weather-sensitive load, such as residential demand impacted by summer air conditioning.



Over the summers of 2018-2021, the actual peak load for BGE's weather-sensitive residential customers averaged 13% higher than the weather-normalized peak load. | *Exelon*

Midgley said the current rules compare metered load under prevailing weather conditions to the peak load contribution (PLC) based on weather-normalized peak weather conditions.

Capacity compliance for DR and PRD is currently based on the firm service level (FSL), calculated as the PLC minus the amount of installed capacity the DR/PRD resource cleared in the capacity auction. Compliance is achieved if metered load is at or below the FSL.

Over the summers of 2018-2021, the actual peak load for BGE's weather-sensitive residential customers averaged 13% higher than the weather-normalized peak load. The disparity was the largest in 2019, with weather-normalized load 22% lower than actual load.

The discrepancy means DR and PRD providers may not be able to offer the full capability of their programs into the capacity market because of unachievable FSL, Midgley said.

BGE proposed the issue be considered by the *Demand Response Subcommittee*, but some stakeholders suggested it would be better referred to the *Resource Adequacy Senior Task Force*.

The committee will be asked to approve the issue charge at its next meeting.

Capacity Offer Opportunities for Generation with Co-located Load

PJM's Lisa Morelli led a discussion on solution *options* for capacity offer opportunities for generation with co-located load. (See "Co-located Load Issue Charge Endorsed," *PJM MIC Briefs: Jan. 12, 2022*.)

Enel X North America, which serves load customers with on-site generation, *said* capacity accreditation for such customers "is a ripe area for review, particularly given technological innovation and direction from FERC Order 2222 to fully value injections from generation sited with load as distributed energy resources.

"Load that is not station power [should be treated] as any other load," Enel said. "Absent a transmission cost being allocated to the co-located load, these costs would be unfairly and unnecessarily passed on to all other ratepayers."

Operating Reserve, Quadrennial Review

Members also continued work on an initiative to *clarify* operating reserve rules for resources operating as requested by PJM (See "Operating Reserve Clarification," *PJM MIC Briefs: Feb. 9, 2022*) and the *Quadrennial Review*, which determines the shape of the variable resource requirement curve, the cost of new entry for each locational deliverability area, and the methodology for determining the net energy and ancillary services revenue offset for the PJM region and each zone. ■

— Rich Heidorn Jr.

PJM Operating Committee Briefs

Internal NITS Process

PJM's Susan McGill last week *reviewed* a proposed *issue charge* and *problem statement* to improve processes for scheduling internal network integration transmission service (NITS).

The RTO said its current tariff makes little distinction between internal and external service requests, requiring all requests be studied to ensure sufficient headroom or need for system upgrades. Internal requests are for internal generation serving internal load; external/cross-border requests refer to external generation serving internal load or internal generation serving external load, respectively.

The initiative seeks to revise the tariff and manual language to differentiate between the two types of requests and reduce administrative burdens on entities using internal service.

The problem statement says the current tariff sets out the process for renewing cross-border service but is "not applicable to internal service requests because the internal generation and load served through internal service are already evaluated and maintained in the existing models used for studies under the Regional Transmission Expansion Process (RTEP)."

The current tariff "requires start and end date durations, creating additional administration burdens to ensure timely rollover rights for internal NITS."

The issue charge proposes to make the following issues out of scope: border service processes associated with NITS; the RTEP process; the pseudo-tie request process; transmission service rates; and the process to integrate new service territory into PJM.

The committee will be asked to approve the issue charge at its next meeting.

'Maximum Emergency' Generation

Members heard a first read of PJM's *Package A*, a collection of proposed manual changes addressing maximum generation status.

In response to concerns over fuel and emissions, PJM made a change last year to section 6.4 of Manual 13 to temporarily modify the remaining hours under which a resource may be offered as "maximum emergency generation." The change, which members endorsed in October, allowed PJM to request resource owners move fuel- or emissions-limited steam units into the "maximum emergency" category if the resource's remaining run hours fall below 240 hours (10 days), an increase from the manual's original remaining run time of 32 hours. Unless required to meet local or regional reliability needs, the units would be restricted from operating during that status, unless their inventory rose above 21 days (504 hours).

The change set out similar rules for combustion turbines, except that they could be moved into maximum emergency status when their remaining run hours on all fuel types fall, or are expected to fall, below 24 hours, versus 16 hours in the original language.

The modifications had an expiration date of April 1, 2022, but the Markets and Reliability Committee eliminated the deadline in March to allow work on a permanent solution. The MRC also approved a *problem statement* and *issue charge*. (See "Max Emergency Changes Endorsed," *PJM MRC/MC Briefs: March 23, 2022*.)

Changes to Deactivation Notification Requirements

PJM reviewed "quick fix" changes to Manual 14D: Generator Operational Requirements regarding the deactivation analysis timeline.

Current rules require notification of PJM at least 90 days in advance of the planned deactivation.

Under the changes, desired deactivation date would be no earlier than:

- July 1 of the current calendar year for notices received between Jan. 1 and March 31;
- Oct. 1 of the current calendar year for notices received between April 1 and June 30;
- Jan. 1 of the following calendar year for notices received between July 1 and Sept. 30; and
- April 1 of the following calendar year for notices received between Oct. 1 and Dec. 31.

PJM will study deactivations four times per year for all notices received prior to the study commencement dates (Jan. 1, April 1, July 1 and Oct. 1).

Deactivation notifications would only require good-faith estimates for a time period if the generation owner requests to mothball the unit.

PJM will notify generation owners by the end of February, May, August and September, respectively, on the results of their reliability analyses.

The committee will be asked to endorse these changes at its next meeting.

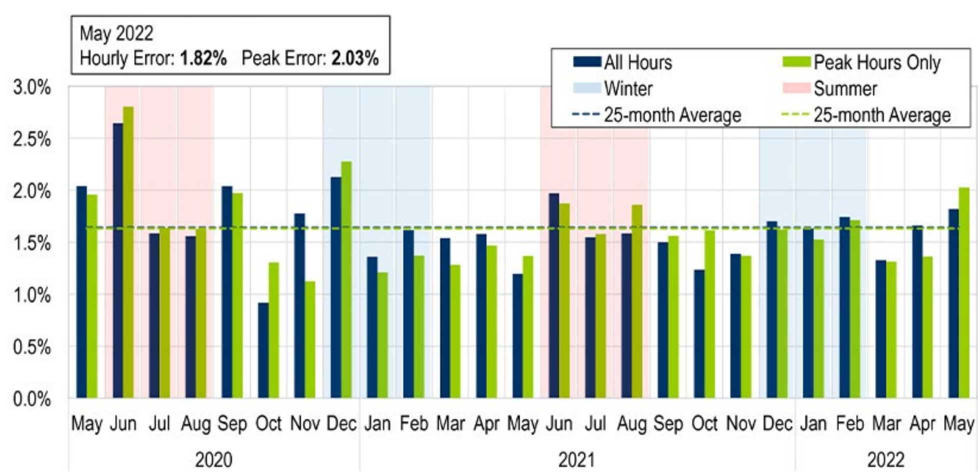
Operating Metrics for May

PJM reported an average load forecast error of 1.82% in May, with a peak hours error of 2.03%, both above the 25-month average, according to the RTO's *operating metrics*.

The RTO continued its unblemished record in 2022 of exceeding its 99% balancing authority area control error limit (BAAL) goal, scoring a 99.8% in May, with 55 excursions totaling 88 minutes outside of limits.

There were four spinning events, three reserve sharing events with the Northeast Power Coordinating Council, 24 post-contingency local load relief warnings and four hot weather alerts. ■

— Rich Heidorn Jr.



PJM reported an average load forecast error of 1.82% in May, with a peak hours error of 2.03%, both above the RTO's 25-month average. | *PJM*

PJM Responds to Market Monitor Recommendations

By Rich Heidorn Jr.

PJM last week issued its *response* to the Independent Market Monitor's latest recommendations, noting that many of the issues are in the scope of current stakeholder discussions.

The Monitor issued 20 new recommendations in its 2021 State of the Market (SOM) *report* in March: seven concerning the energy market; eight concerning the capacity market; two on demand response; and one each on environmental regulations, ancillary services and financial transmission rights. (See *PJM Monitor: Prices, Coal Power Bounced Back in 2021*.)

Energy Market Recommendations

PJM said that two of the energy market recommendations — regarding the capping of the system marginal price in real-time security constrained economic dispatch, and implementing an extended downward sloping operating reserve demand curve (ORDC) — were "superseded" by a December 2021 FERC order on voluntary remand from the D.C. Circuit Court of Appeals. (See *FERC Reverses Itself on PJM Reserve Market Changes*.)

The RTO said it responded to the order with a proposal to retain the existing reserve market and energy market price capping framework "largely consistent" with the SOM recommendation. But it said it has no plans to implement downward sloping demand curves for operating reserves because the commission rejected it.

PJM said it addressed another Monitor recommendation — requiring generators that violate their approved turn-down ratio to demonstrate that their actions are based on an actual physical constraint — in its response to a June 2021 FERC order to show cause. The commission ruled that PJM's tariff appeared to allow market sellers to circumvent being subject to parameter-limited offers. (See *FERC Issues Show-cause Order on PJM Parameter-limited Offers*.)

The RTO responded to FERC by instituting an interim rule restricting the use of real-time values to actual physical limitations that occurred during the real-time market. "PJM believes these interim limitations sufficiently address concerns that market sellers could submit real-time values to inappropriately limit their flexibility, since economic reasons for adjusting parameter limits are no longer acceptable reasons to override unit-specific parameters," PJM said.

However, the RTO disagreed with the Monitor's proposal to require that capacity resources be required to use flexible parameters in all energy offers at all times to mitigate market power.

"PJM disagrees that capacity resources have broad 'obligations to be flexible' under the current capacity market construct," the RTO said, adding that "flexibility is not an explicit requirement for the qualification for capacity resources [and] is largely not accounted for in the accreditation of capacity resources."

It also rejected the IMM's call for adjusting ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by the amount of reserves deployed.

"PJM views this recommendation to be inconsistent with the NERC standard that obligates PJM to procure contingency reserves and also with PJM's policy for maintaining adequate reserves," it said. "PJM's current policy regard-

ADOPTED & ACTIVE RECOMMENDATIONS

Section	ADOPTED	ACTIONABLE	ASSESSMENT	ARCHIVED	Section Percentage
Ancillary Services	1	11	8	6	25%
Capacity Market	3	12	3	3	21%
Demand Response	0	0	1	3	4%
Energy Market	1	5	3	17	25%
Energy Uplift	0	4	2	3	9%
Environmental	0	1	0	0	1%
FTRs & ARRs	1	3	0	0	4%
Interchange Transactions	0	3	0	3	6%
Net Revenue	0	1	0	0	1%
Planning	0	1	3	0	4%
Total Recommendations	6	41	20	35	102
Status Percentage	6%	40%	20%	34%	

PJM's responses to recommendations in the Independent Market Monitor's State of the Market reports through 2021. Actionable recommendations are the highest priority items, on which PJM plans to take action in the coming year. Assessment recommendations are of medium importance but need further investigation to determine if they are actionable. Archived recommendations are low priority and are not being pursued. | *PJM*

PJM News

ing reserves is intended to restore reserves as quickly as possible following their deployment. The purpose of this is to make sure that the PJM system can respond to successive contingencies should they occur."

Capacity Market Recommendations

PJM said the Resource Adequacy Senior Task Force, which began work in December, is discussing a range of potential rule changes that could address several of the Monitor's capacity market proposals.

Among them:

- that the value of capacity transfer rights be defined by the total megawatts cleared in the capacity market, the internal megawatts cleared and the imported megawatts cleared, and not redefined later prior to the delivery year;
- that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed;
- that PJM improve the clarity and transparency of its capacity emergency transfer limit (CETL) calculations and that the CETL for capacity imports be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must-offer requirement;
- using the lower of the cost- or price-based energy market offer to determine energy costs in the calculation of the historical net revenues;
- that any combined seasonal resources be required to be in the same locational deliverability area to ensure the energy and capacity markets remain synchronized and reliability metrics correctly calculated.

Some other recommendations are under discussion in other venues, PJM said.

The Monitor's call to bar storage and other intermittent resources from offering capacity megawatts based on energy delivery that exceeds their capacity interconnection rights (CIRs) is among the issues being discussed at the Planning Committee's special sessions on CIRs for effective load-carrying capability resources, PJM said.

The IMM's call for PJM to re-evaluate the shape of the variable resource requirement curve will be considered as part of the Market Implementation Committee's current Quadrennial Review, the RTO said.

Demand Response, FTRs

PJM rejected the Monitor's proposal that electric distribution companies (EDCs) not be allowed to participate in markets as distributed energy resource aggregators in addition to their EDC role.

"This recommendation is inconsistent with FERC Order No. 2222, in which the commission affirmed that 'market participation agreements for distributed energy resource aggregators should not preclude distribution utilities, cooperatives or municipalities from aggregating distributed energy resources on their systems," PJM said. "Accordingly, PJM's DER Aggregator Participation Model, proposed as a component of PJM's Order 2222 compliance filing, does not prohibit a distribution utility from forming its own DER aggregation resources. This is consistent with current practice today, where certain distribution utilities participate in the PJM demand response program with their own load reduction resources."

The RTO acknowledged, however, that the DER Aggregator Participation Model, which will "require a greater level of distribution utility coordination to ensure safety and reliability … sets up a scenario in which a distribution utility — the entity responsible for physically operating its distribution facilities and overriding PJM dispatch of other DER aggregators — may also be competing against other DER aggregators connected to those same distribution facilities."

"PJM acknowledges concerns regarding this potential conflict of interest and anticipates continued dialogue with states and stakeholders on how state and local law may address this issue," it said.

The RTO's report renewed its disagreement with the Monitor over the proper confidence interval when calculating initial margin requirements for FTR market participants.

Although the Monitor recommended the use of a 99% confidence interval, PJM proposed 97%, which was rejected by FERC as unsupported by the record. (See *Stakeholders Encourage PJM to Defend FTR Filing*.)

The RTO maintains that the 97% option is "the most cost beneficial proposal" and that the increased collateral costs at 99% is greater than the benefit in reduced defaults.

"Based on this and other additional analysis, PJM believes it can supplement the December [Federal Power Act Section] 205 filing with additional evidence to support use of the 97% confidence interval to address most of FERC's concerns," it said. ■

Company Briefs

Shell Launches Renewable Power Brand

Shell last week announced it was entering the residential electricity market in Texas by offering renewable power under a new brand called Shell Energy Solutions.

Shell previously acquired MP2 Energy, a power retailer with 33,000 customers, that will now carry the Shell Energy Solutions flag.

The move is the company's latest step to reach net-zero emissions by 2050 and reposition itself as a broader energy provider.

More: *Houston Chronicle*

BWXT Subsidiary to Build First US Nuclear Microreactor

BWXT Advanced Technologies, a subsidiary of nuclear components and fuel supplier BWX Technologies, last week announced it will build the first advanced nuclear microreactor in the nation under a $300 million contract awarded by the Department of Defense's Strategic Capabilities Office.

The transportable reactor prototype, known as Project Pele, is set to be delivered in 2024 and tested at the Idaho National Laboratory for three years. The objective is to design, build and demonstrate a mobile nuclear reactor within the next five years that will allow the department to reduce its carbon emissions while having a resilient power source.

More: *Virginia Business*

EV Maker Electric Last Mile Solutions to File for Bankruptcy

Electric vehicle maker Electric Last Mile Solutions last week said it plans to file for Chapter 7 bankruptcy following a review of its products and commercialization plans.

The decision comes after the company disclosed a probe by the Securities and Exchange Commission and withdrew its previously issued business outlook in March. ELMS had said the SEC was investigating matters discussed in prior filings, including disagreements with an accounting firm and compliance with the Nasdaq's listing rules.

More: *Reuters*

Canadian EV Charging Company Invests $3M in First US Facility

Canadian electric charging company FLO last week announced it will make a $3 million investment to bring its first U.S. manufacturing facility to Auburn Hills, Mich.

FLO, a subsidiary of AddEnergie, offers home charging equipment for both single-family houses and multi unit residential buildings, as well as access to thousands of public charging stations, according to the company's website. It plans to produce 250,000 EV chargers by 2028.

More: *Michigan Live`*

Federal Briefs

Solar Companies Weigh Challenge to Biden's Tariff Pause

U.S. solar manufacturers last week said they are considering legal challenges after President Joe Biden declared a two-year pause for tariffs on solar imports from Southeast Asia.

Some domestic producers, including Auxin Solar, the California company that filed a complaint with the Commerce Department about unfair competition from Chinese imports, said Biden's actions would help China's state-subsidized solar companies at the expense of U.S. manufacturers.

A Biden administration official said the president's decision was driven by White House climate adviser Gina McCarthy and climate envoy John Kerry, along with Energy Secretary Jennifer Granholm. The officials are concerned that the Commerce inquiry jeopardized Biden's goal to achieve 100% clean electricity by 2035.

More: *The Associated Press*

Freeport LNG Plant Shut Down for 3 Weeks

Freeport LNG, the operator of one of the largest U.S. liquefied natural gas (LNG) export plants, last week said it will shut for at least three weeks following an explosion at its Texas Gulf Coast facility.

A company spokesman said an investigation into the explosion has begun.

Freeport LNG provides around 20% of U.S. LNG processing and can process up to 2.1 billion cubic feet of natural gas per day.

More: *Reuters*

US Firms Secure 19 Deals to Export LNG

Since the Russian invasion of Ukraine on Feb. 14, American companies have secured at least 19 agreements to supply nearly 24 million tons of LNG per year, the Environmental Integrity Project (EIP) reported last week.

At least a quarter of that total will go to European buyers.

Construction continues on four new LNG export terminals expected to open by 2026. In all, the EIP counts 25 LNG projects that are either under construction or in the planning stages.

LNG produced in the U.S. is exported from seven terminals that have the capacity to produce up to 104.5 million tons per year.

More: *Inside Climate News*

Utah Hydrogen Storage Project Garners $504M DOE Loan

The Department of Energy last week announced that its first official loan guarantee for a new clean energy technology project since 2014 will go to the Advanced Clean Energy Storage 1 project in Utah, which figures to be one of the largest renewable hydrogen energy projects in the world.

The DOE said it closed on the $504.4 million loan guarantee for the first phase of the project. It will be spearheaded by ACES Delta — a joint venture between Magnum Development, Mitsubishi Power and Haddington Ventures.

The project aims to produce up to 100 metric tons of hydrogen from water and renewable energy sources daily using a 220-MW alkaline electrolyzer bank. ACES Delta will store that hydrogen in two solution-mined caverns, each of which can store up to 150 GWh of energy.

More: *POWER Magazine*

Biden Nominates Kentucky, Mississippi Leaders for TVA Board

President Joe Biden last week nominated Adam "Wade" White of Kentucky and William Renick Sr. of Mississippi for the Tennessee Valley Authority Board of Directors.

The TVA board is currently comprised of individuals from Tennessee and Georgia after the five-year terms of former board members in Kentucky, Mississippi and Alabama expired. Only five of the board's nine seats are filled, while three of those directors could leave TVA by the end of the year.

Nearly a year and a half after taking office, Biden has yet to get anyone confirmed as a TVA director, and the board remains comprised entirely of members appointed by former President Donald Trump.

More: *Chattanooga Times Free Press*

State Briefs

ARKANSAS

EV Registrations up 43% in 1 Year

Electric vehicle registrations are up 43% in the first five months of 2022 compared with the same period in 2021, the Department of Finance and Administration said.

The number of hybrid EVs also grew from 22,818 to 27,441 in the first five months of this year.

Between the end of 2019 and the end of May 2022, the number of full EVs registrations (2,997) has risen 283.7%.

More: *KUAR*

CALIFORNIA

PG&E Pleads Not Guilty in Zogg Wildfire

Pacific Gas & Electric last week pleaded not guilty to involuntary manslaughter and other charges it faces after its equipment sparked the 2020 Zogg Fire that killed four people and destroyed hundreds of homes in Northern California.

PG&E was arraigned on 31 criminal counts and enhancements, including four counts of involuntary manslaughter, after being accused of recklessly starting the fire, the Shasta County District Attorney's Office said. A preliminary hearing in the case was set for January.

Investigators concluded the fire was sparked by a pine tree that fell onto a PG&E distribution line. The district attorney determined that the company was criminally liable for the fire and charged the utility last September.

More: *The Associated Press*

SoCal Edison Says Electrical Component Showed Signs of Damage

Southern California Edison last week said an electrical component used to connect two power lines in the area of the Coastal Fire showed signs of damage.

The utility revealed the discovery in a report but said it did not know when the damage occurred or whether it contributed to the start of the fire. Authorities have yet to determine the fire's origin.

The Coastal Fire was first reported on May 11 in Aliso Woods Canyon near Laguna Niguel. At least 20 homes burned; 900 homes were evacuated.

More: *KNBC*

COLORADO

Pueblo County Rejects Solar Park

Pueblo County commissioners last week voted against the Pronghorn Solar Park development, which would have built a solar array on 831 acres of private land near the Comanche power plant.

Pushback from residents and concerns about property values were among the reasons cited by the commissioners for voting no.

More: *The Pueblo Chieftain*

Xcel Energy Gets Approval for $2B Tx Project

The Public Utilities Commission approved Xcel Energy's plans for its $2 billion Colorado's Power Pathway transmission line, which will upgrade the state's high-voltage transmission system.

The pathway will consist of loops of up to 650 miles of high-voltage lines stretching from the Fort St. Vrain gas-fueled plant to the southeastern plains. Four new and four expanded substations are planned. The PUC gave conditional approval to a 90-mile extension in the southeast, pending more information.

Xcel said it will recover costs through cost-adjustment riders on bills as the project's components are placed in service.

More: *The Denver Post*

ILLINOIS

New Details on ComEd Bribery Probe Emerge

Newly unsealed search warrants in the Commonwealth Edison bribery probe provided more details about the alleged behind-the-scenes effort to kill an energy bill.

According to the charges, former House Speaker Michael Madigan quietly greenlighted efforts to kill his own daughter's legislation as he pressed ComEd to give jobs to two political allies. The legislation, aimed at helping low-income electricity customers, was opposed by ComEd.

Madigan also allegedly told ComEd CEO Anne Pramaggiore they had to "kill" the bill during a recorded phone call. The utility worried expanding eligibility for low-income customers would raise prices for other customers.

More: *Chicago Tribune*

INDIANA

Muncie Votes Down Solar Field at Former GM Plant

The Muncie City Council last week voted 5-4 to deny turning 53 acres of a former GM plant into a solar energy field.

Councilmembers and residents questioned the project's cost and liabilities, along with the overall usage of the land.

More: *WBOI*

St. Joseph County Solar Farm Moves Forward

St. Joseph County commissioners last week approved a revamped development agreement for a $164.7 million solar farm proposed by Lightsource BP.

Original language in the development agreement, which was previously approved by the Redevelopment Commission, encouraged the company to employ as many local workers as possible during the construction phase of the 150-MW project. But the revised agreement says the company will aim to hire 75% of the estimated 150 to 200 construction workers from St. Joseph County or its immediate neighbors.

The agreement will now go to the Redevelopment Commission and County Council for approval.

More: *South Bend Tribune*

KANSAS

Johnson County Amends Regulations Guiding Solar Developments

The Johnson County Commission last week voted 6-1 to soften development regulations to allow solar projects as large as 2,000 acres, solar fields as close as 1.5 miles from city boundaries, and operational permits of 25 years in length.

More conservative limits recommended by the county's planning commission were rejected, including a maximum farm size of 1,000 acres, a 2-mile buffer from cities, and a 20-year permit.

The regulatory framework was in response to interest by NextEra Energy Resources in building solar collection arrays in two eastern counties.

More: *Kansas Reflector*

KENTUCKY

2 Men Die After Falling into Drainage Collection System

Two workers died last week at Big Rivers Electric Corporation's Green Station power plant after they fell into a confined drainage system.

The Henderson County Coroner's office identified the workers as 34-year-old Eric Williams and 39-year-old Phillip Hill. Big River Electric Corporation spokeswoman Stephanie McCombs said Williams and Hill died while working on the company's Sebree Station property, adjacent to the Green Station plant.

An investigation of the incident is ongoing.

More: *Evansville Courier & Press*

MARYLAND

DOI to Review Environmental Impact of Proposed OSW Project

The Department of the Interior last week announced it will conduct an environmental review of US Wind's proposed wind farm 11 miles off the coast of Ocean City.

The department's Bureau of Ocean Energy Management will publish a notice of intent to review the company's plan for construction, which is expected to begin by the end of 2023. The bureau will hold three virtual public scoping meetings to inform the preparation of the environmental impact statement on June 21, 23 and 27.

More: *WJZ*

MICHIGAN

305 Farms Receives $848K Rebate for Energy Efficiency

An indoor cannabis grower, 305 Farms, was awarded a $848,000 rebate from Consumers Energy for being energy efficient.

The rebate from Consumers Energy was given as part of its effort to bolster new and existing companies' energy efficiency.

More: *WXMI*

Goodland Township Denies Solar Project

The Goodland Township Planning Commission last week voted 5-1 to deny a special land-use permit for a 1,600-acre solar facility sought by Orion Renewable Energy.

Orion proposed building a $100 million, 100-MW solar field. However, most of the officials said the project would not be in harmony with existing agricultural and residential uses in the township.

More: *The County Press*

MISSOURI

Ameren to Pay for Coal Plant's Illegal Pollution

The Department of Justice wants Ameren to develop "a suite of proposals" to atone for longstanding air pollution at its coal-fired Rush Island Energy Center, according to court documents.

The Justice Department outlined examples Ameren could be ordered to pursue to improve regional air quality, according to the filing, such as investing in energy storage to aid renewable power projects, planting trees, or helping pay for air filtration systems in schools and homes.

An Ameren spokesman declined comment and said the company was working on a legal response and awaiting the results of a study on the effects of the plant's closure on the grid.

More: *St. Louis Post-Dispatch*

OHIO

Cleveland Council Calls on FirstEnergy to Forfeit Browns Stadium Naming Rights

The Cleveland City Council last week voted 16-1 to pass a resolution calling on FirstEnergy Corp. to relinquish its naming rights to the publicly owned Browns' football stadium. However, the council has no legal authority to force a change.

FirstEnergy Stadium has been the name of the Browns' home since the company bought the naming rights in 2013 for $107 million.

More: *WJW*

RHODE ISLAND

Senate Approves OSW Procurement Bill

The Senate last week unanimously approved legislation that will require utilities to buy 600 MW of offshore wind power.

The legislation gives v., the owner of newly renamed Rhode Island Energy, until Oct. 15 to publish a solicitation seeking to buy another 600 MW worth of offshore wind. Added to the state's existing renewable sources, the massive power boost would enable it to meet 80% of its current electricity needs from renewable sources and put the state well on its way to its goal of 100% renewable electricity by 2030.

Companion legislation remains in the House Corporations Committee.

More: *Providence Business News*

TEXAS

Bitcoin Miners Powering Down Amid Heatwave, Electricity Demand

State bitcoin miners last week set agreements with ERCOT to power down their operations at peak energy demand times.

Companies Bitdeer, Argo and Riot have all adjusted their operations due to high temperatures and energy demand.

Energy demand hit a peak of 72,386 MW on June 6, setting a record for the month — only to be surpassed the following day when demand hit 72,785 MW, according to data from ERCOT.

More: *The Block*

VIRGINIA

Appalachian Power Issues Request for Renewable Projects

Appalachian Power last week issued two requests for proposals to help the company meet its goals under the Virginia Clean Economy Act, under which the company must meet annual requirements as it works toward 100% carbon-free energy by 2050.

Appalachia is seeking proposals for up to 100 MW of solar and/or wind resources via one or more long-term power purchase agreements, and for unbundled renewable energy certificates.

More: *Appalachian Power*

WYOMING

rPlus Hydro Seeks Approval for Pumped Storage Project

rPlus Hydro, a subsidiary of renewables developer rPlus Energies, last week submitted a draft license application for a 900-MW pumped storage project.

The Seminoe Pumped Storage project will require an investment of around $2.5 billion to create the first pumped hydro storage complex in the state, the developer said.

The filing of the application starts a 90-day agency review process ahead of the submission of the final license application to FERC.

More: *Renewables Now*

National/Federal news from our other channels

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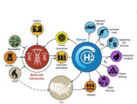
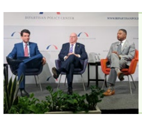
Status of Corporate Net-zero Pledges is 'Bleak,' Researcher Says — NetZero Insider



DOE Conference Details Massive R&D Effort on Clean Hydrogen — NetZero Insider



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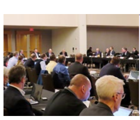

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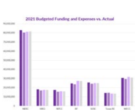

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