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YES ENERGY

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Trump Signs Big Beautiful Bill into Law on Independence Day

Clerk of the House

Republicans cut funding for clean energy to balance tax cuts and other spending in their bill, which many in the industry have said will only lead to higher prices by kneecapping important sources of supply at a time of rising demand in many parts of the country.

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In this week's issue

You Might not Know the Drill; New Geothermal Technology is on the Doorstep

By Peter Kelly-Detwiler


Peter Kelly-Detwiler

Until now, a carbon-free, load-following electric supply resource has been elusive. That may be about to change because of a resource that sits literally right below our feet — even if it is a mile or more down. That supply resource is the earth's heat, which radiates continuously from the earth's core, and entrepreneurs are quickly figuring out how to tap it.

Developers have been accessing *traditional geothermal energy resources* for decades in those limited areas of the world where hydrothermal resources exist in the form of hot springs, geysers, volcanoes and fumaroles. These areas typically are near tectonic plate boundaries. In this country, *93%* of the 3,700 MW of installed capacity is located in these more geologically active areas of California and Nevada. In recent years, though, development of domestic hydrothermal resources has stagnated.

Fortunately, a much larger geothermal resource exists that is more geographically widespread, and it doesn't require the presence of existing underground water. Developers are tapping into this unconventional geothermal asset by using specialized equipment to drill holes miles deep into hot, hard rock — often granite.

Using techniques developed in the hydrocarbon fracking industry, specialized technicians drill at depth, then rotate the drills 90 degrees and guide them laterally to develop horizontal boreholes in the hot zones that often exceed 300 degrees Fahrenheit. Instead of relying on existing underground water resources, developers bring their own working fluids, typically water but also high-pressure supercritical carbon dioxide (neither a gas nor a liquid). These working fluids are circulated deep underground to harvest the rock's ambient heat and bring it back to the surface, where it creates steam to spin turbines and generate power.

A Sage Geosystems demonstration project in 2022, located near McAllen in South Texas. | *Sage*

Drilling for Heat, not Hydrocarbons

This new geothermal industry already is branching off into multiple approaches, some of which may work better than others based upon local conditions. Today, the two main approaches are called enhanced and advanced geothermal.

Enhanced geothermal: The enhanced geothermal companies typically drill parallel wells and then frack the rock between the wells using high-pressure water. This creates fissures in the rock and establishes permeability and connectivity between two wells. An injection well introduces water into the system, which heats up when it contacts the broad surface areas in the broken rock. The second withdrawal well draws the heated water back to the surface for electricity generation.

Just as with hydrocarbon fracking, developers can punch multiple wells into the earth from a single pad, minimizing drilling time and surface area impacts. *Fiber optic cables collect data* relating to temperatures and the flow of the working fluids that capture and "mine" the heat from the rock. The trick is to optimize the flow of fluids to capture the maximum amount of heat extracted to the surface.

Advanced geothermal: With advanced geothermal development, some operators drill vertically and then horizontally, but rather than fracking the rock, they install a lining in the hole to create closed-loop circuits, essentially developing underground inverse radiators. Others use a pipe-within-a-pipe system, sending water down in one pipe and withdrawing it through the other. In either case, a finite quantity of working fluid — either water or supercritical CO_2 — is injected into the closed system, heated by the surrounding rock, and then brought back to the surface. The use of supercritical carbon dioxide requires special turbines, but because it boils and creates high-pressure steam at lower temperatures, it can further enhance output.

The first commercial contracts point the way: Within the past year, leaders in this nascent industry have inked the first meaningful deals. Pathbreaker *Fervo Energy signed its first 3-MW* proof-of-concept contract with Google in late 2023. It then turned its attention to developing a far larger effort in Cape Station, Utah, and *has signed contracts* with Shell Energy, Clean Power Alliance and Southern California Edison, with initial deliveries from its 500-MW facility beginning next year.

Fervo also *recently received regulatory approval for a contract* to deliver 115 MW of electricity to Google through Nevada utility NV Energy. Other geothermal players

also are inking agreements. Last August, *Sage Geosystems announced a deal with Meta for 150 MW* of geothermal energy in Texas, to be commissioned by 2027. In June, *XGS Energy and Meta hailed an agreement* for 150 MW of geothermal to be developed in New Mexico, with an online date of 2030, and in May, *Exceed Geo Energy announced a 110-MW contract* with Presidio Municipal Development District, with the first 9.9 MW to be online in late 2026.

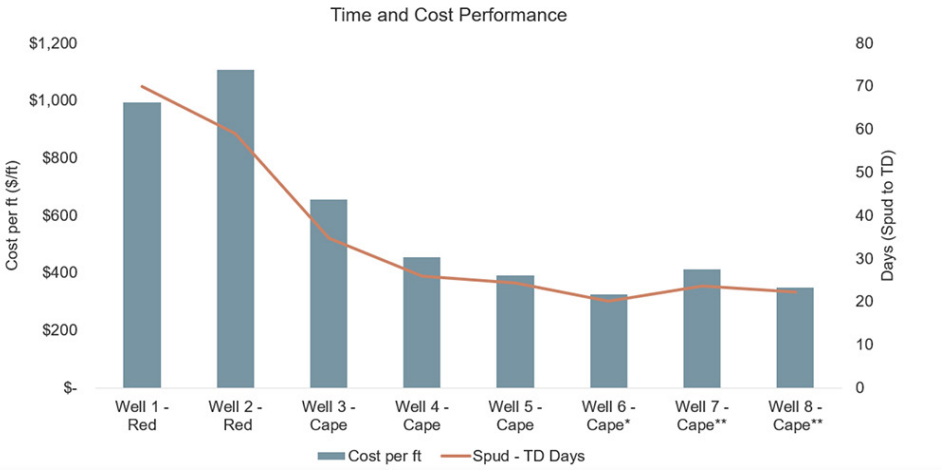
Technological advancements: Just as the fracking industry saw rapid technological development and improvements resulting in lower costs, the new geothermal players also are pushing the envelope as they drill deeper into challenging heat and hard rock environments. They use tools and practices adopted from conventional drilling and fracking and adapt those to their specific industry. These include specialized polycrystalline diamond drill-bits, specialized lubricants and additions to the drilling mud that keep the well cool enough for the equipment to operate.

A *recent paper evaluating drilling speeds and costs* demonstrated significant progress — in terms of speed, required number of drill bits and related costs — with each new well drilled. In the example cited, Fervo was able to demonstrate a 60% improvement in drilling speeds over just eight wells.

Faster Wells for Less Money

Multiple players, with a growing pot of money: There are more than *a dozen geothermal startups* in the U.S., with Texas seeing the greatest concentration. Together, they have been *funded with more than $2 billion* (Fervo just raised an additional $206 million for project financing in June).

Many companies are far enough along in their efforts that 11 of them have been *pre-qualified by the U.S. Department of Defense* for projects on military bases (and seven pilots reportedly are in the works). Most are adapting existing oil and gas technology, but startup Quaise is using a different approach. It emulates others by drilling to initial depths using conventional technology. However, it then plans to go far deeper than its competitors — as far as 12.5 miles down to access heat over 900 F — and to achieve this goal, it is testing high-powered millimeter waves that vaporize holes in the rock.



Fervo horizontal well cost per ft and spud to TD trends | *Stanford University*

Size of potential resource: Studies suggest the geothermal resource is enormous. A *June 2025 study looking at New Mexico* estimates as much as 163 GW of potential geothermal production, 15 times the state's installed capacity. At the national level, a 2024 *Department of Energy Lift-off study* suggested a potential 90 to 130 GW of installed capacity over the next 25 years.

The Potential is There, but can we Cost-effectively Access it?

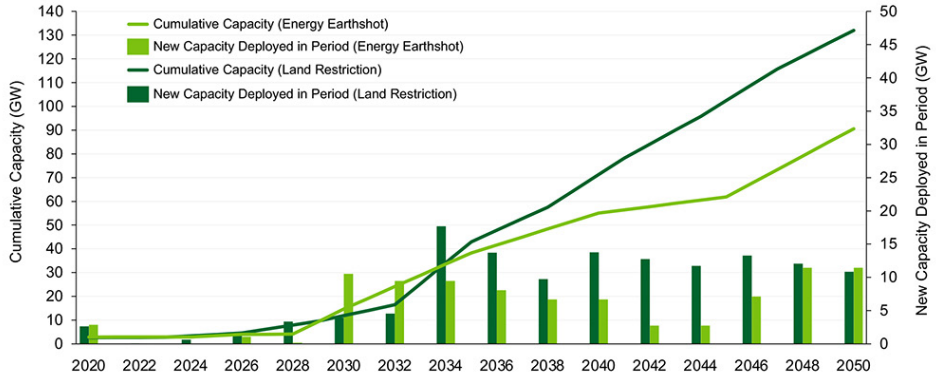
That number would represent a fraction of the 7,000 GW of national potential at three miles deep, and 70,000 GW accessible at all depths. There's one inherent challenge here, though: The geology of the United States clearly favors the West, where drillers can access heat at far shallower depths. Because going deeper has been prohibitively expensive and time consuming until now, the Eastern U.S. has been largely excluded from consideration.

Drill West, Young Man!

That may be changing, though, as evidence is beginning to suggest that perhaps these deeper depths are more easily attainable. Fervo *announced in June that it had drilled a new well* to a depth of 15,765 feet (75 feet shy of three miles!) in only 16 days, accessing temperatures in the range of 520 F. Furthermore, it was able to drill laterally through the hard rock at that depth at an impressive rate of over 300 feet per hour.

Hype or real reason for hope? While it's still too early to tell, and early capital certainly will be deployed where drilling is easier and more cost-effective, we may see an industry expansion to the east in the visible future. For the emerging unconventional geothermal industry, the theoretical potential is there and the first facts on (and in) the ground are promising.

The industry already has viable and tested technology, successes, financing and the first commercial contracts in hand. It also may have continued government support in the form of continued tax credits and a relatively easy permitting process for projects on federal lands. We will know a lot more about just how real this industry is in just a few short years. ■



Estimated next-generation geothermal deployment potential | *DOE*

Trump Signs Big Beautiful Bill into Law on Independence Day

By James Downing

After it took Republican leadership most of the previous day cajoling its members, the House of Representatives on July 3 voted *218-214* to pass the Senate version of its budget reconciliation package, the One Big Beautiful Bill Act, just in time for President Donald Trump to sign it into law by his imposed deadline of July 4.

"The House has passed generational legislation that permanently lowers taxes for families and job creators, secures the border, unleashes American energy dominance, restores peace through strength, reduces spending more than any other bill has, and makes government more efficient and effective for all Americans," Speaker Mike Johnson (R-La.) and other Republican leaders said in a joint statement.

The bill makes permanent tax cuts enacted during Trump's first term and slashes federal funding, including on tax credits for renewable energy and other programs Democrats passed in the Inflation Reduction Act of 2022. (See related story, *Senate Passes Trump's Big Bill that Slashes Clean Energy Tax Credits*.)

Republicans kept the voting open for hours to secure passage, which was delayed by a record-long speech on the floor by Minority Leader Hakeem Jeffries (D-N.Y.). The entire Democratic caucus voted against the bill, as did two Republicans.

"Our House Republican colleagues, Mr. Speaker, have one last opportunity to join us … to stand up and protect the health care of the American people; stand up and protect the nutritional assistance of the American people; stand up and protect our farmers; stand up and protect our veterans; stand up and protect the clean energy economy; stand up to protect our public schools," Jeffries said.

Speaker Mike Johnson (R-La.) addressed the House floor on July 3 as the voting process was nearing an end. | *Clerk of the House*

The clean energy provisions were highly criticized by trade groups representing developers and environmentalists, but investor-owned utility trade group Edison Electric Institute said the bill had some benefits for its members, including lower corporate tax rates and interest deductibility, and supported some energy tax provisions.

"Our top priority is delivering affordable, reliable energy to hundreds of millions of Americans. We support the many provisions in the bill that help us achieve this goal and grow our economy," EEI President Drew Maloney said in a statement. "We will continue to work with the administration and lawmakers to implement and develop policies to support energy infrastructure investment and keep customer bills as low as possible."

Clean energy supporters said that with rising demand, the bill's changes and cuts to tax credits for renewable resources will only raise prices for consumers.

"While the new policies are a step backward, the combination of surging demand for electric power and economic benefits of renewable energy technologies ensure that clean power will continue to play a significant and growing role in our nation's energy mix,"

Why This Matters

Republicans cut funding for clean energy to balance tax cuts and other spending in their bill, which many in the industry have said will only lead to higher prices by kneecapping important sources of supply at a time of rising demand in many parts of the country.

American Clean Power Association CEO Jason Grumet said in a statement. "America's electricity demand is projected to surge by as much as 50% by 2040. That growth requires every available source of reliable power, including the clean energy technologies that are the only shovel-ready sources of additional power and the low-cost option across much of the nation."

While the two parties have now used reconciliation in recent years to enact major swings in clean energy funding, one area they have so far failed to move on is permitting reform, despite both sides of the aisle having support for the concept.

"Permitting reform can and should be a bipartisan focus for members in the coming weeks and months that remain in this Congress," Americans for a Clean Energy Grid Executive Director Christina Hayes said in a statement. "America's transmission grid is at a crossroads. No matter your politics, the reality is clear: Demand for electricity is rising. Whether that power comes from natural gas, coal, nuclear, wind or solar, none of it will reach homes, businesses or data centers without a modern, reliable and expanded transmission network. As technology advances, we must ensure our grid can keep up — or risk losing America's dominance in the global competition for advanced manufacturing and artificial intelligence."

The Clean Energy Buyers Association represents many of the big tech firms behind the surge in data centers and other large energy users whose total demand is bigger than any U.S. state. CEO Rich Powell saw mixed results in the bill and seconded the call for "fundamental reforms to our national permitting system."

"We regret that the tax credits for solar and wind are being sunset at a difficult time when we need all energy options to support unprecedented electricity growth in America," Powell said. "We do acknowledge and appreciate the work of President Trump and Congress in expanding the critical policies needed for clean firm energy, such as nuclear, batteries and geothermal, to support the next generation of carbon emissions-free energy resources. America's energy dominance depends on our ability to lead in the technologies of the future and to continue to invest in all forms of clean energy."

The Business Council for Sustainable Energy said the bill will hold the U.S. energy industry back, though renewables and efficiency should continue to grow in spite of it.

"Compared to earlier proposals, the final legislation provides a more workable transition for some energy businesses currently utilizing federal energy tax credits," BCSE President Lisa Jacobson said in a statement. "However, it imposes many rapid changes to various energy credits that will cause uncertainty and increase energy costs. These provisions include consumer credits for energy efficiency and clean energy that help lower energy costs for families and businesses, make the grid more resilient, protect good American jobs and provide certainty for vital investments in the energy sector." ■

Senate Passes Trump's Big Bill that Slashes Clean Energy Tax Credits

By James Downing

The U.S. Senate met through the weekend and overnight June 30 to work on Republicans' budget reconciliation bill, passing it 51-50 with Vice President JD Vance casting the tiebreaking vote around noon July 1.

The One Big Beautiful Bill Act includes most of the Trump administration's legislative priorities, such as earlier phaseouts of clean energy tax credits, but the Senate took out some of the most heavily criticized aspects, including a tax on the production of solar and wind power that was only introduced over the weekend. (See *Renewables Supporters Decry Late Change to Trump's 'Big Beautiful Bill'*.)

President Donald Trump welcomed the Senate vote in a post on Truth Social, saying it will lower taxes, raise wages, secure the country's borders and lead to a stronger military.

But American Clean Power Association CEO Jason Grumet said in a statement that "the Senate reconciliation package is a step backward for American energy policy. The intentional effort to undermine the fastest-growing sources of electric power will lead to increased energy bills, decreased grid reliability and the loss of hundreds of thousands of jobs."

Grumet noted, however, that it could have been worse. The 12-month phaseout of the tax incentives is aggressive, but the final bill did not include the production tax.

"We appreciate the members of Congress who worked to get this legislation to a better place," Grumet said. "Their efforts reinforce the basic principle that Congress should not bet against progress in any part of our economy."

The House of Representatives is expected to quickly take up the Senate version of the bill, having already passed another version with different language on energy tax credits. The House Rules Committee met hours after the Senate passed the bill, clearing the way for it to reach the floor and possibly meet Trump's personal deadline of getting the bill fully passed by July 4.

"We can have all of this right now, but only if the House GOP UNITES, ignores its occasional 'GRANDSTANDERS' (You know who you are!) and does the right thing, which is sending this bill to my desk," Trump said in his post. "We are on schedule — let's keep it going and be done before you and your family go on a July 4 vacation."

ClearPath Action, a conservative group that supports addressing climate change, argued that the bill keeps in place enough tools for industry to move forward on the next generation of clean energy technologies.

"The private sector needs all tools available, including tax credits and faster permitting, to meet the goals of increasing reliable electricity and lowering costs in an era of rising demand," ClearPath CEO Jeremy Harrell said in a statement. "The reconciliation process started with calls from some to fully repeal all energy tax incentives, which would have devastated the ability to build new clean energy. Senate Republicans and House allies rejected that approach and preserved some financial tools to accelerate American innovation and invest in American manufacturing. We encourage House Republicans to swiftly pass this bill with the key energy provisions included."

The U.S. Capitol | *David Maiolo, CC BY-SA-3.0, via Wikimedia Commons*

Why This Matters

Democrats forced through clean energy tax credits in the Inflation Reduction Act in 2022. Republicans now have cut those off early using the same reconciliation techniques.

The Senate bill keeps incentives for advanced nuclear, geothermal, hydropower and storage through 2032, while wind and solar credits would be phased out in 2027. It preserves the transferability provisions for the life of each energy credit and retains the 45X advanced manufacturing incentive to support domestic production of critical minerals and certain energy components. It also provides new financing authority for the Department of Energy's Loan Programs Office to support nuclear, geothermal and energy supply chains.

The Natural Resources Defense Council said the bill cuts tax credits for the fastest-growing source of new generation and is expected to lead to higher power bills around the country.

"With spiking power demand and rising bills, we need more clean, affordable American energy, but Senate Republicans just voted to kill jobs and deliver the largest utility bill increase in U.S. history," NRDC CEO Manish Bapna said in a statement. "This measure props up the dirty and expensive technologies of the past while strangling the clean energy investments that are creating millions of jobs across the country. At a time when we need new energy more than ever, Republicans are punishing the plentiful wind and solar power that can be quickly added to the grid." ■

DOE Reliability Report Argues Changes are Required to Avoid Outages Past 2030

By James Downing

The U.S. Department of Energy released a report July 7 saying that retirements and delays in new firm capacity "will lead to a surge in power outages and a growing mismatch between electricity demand and supply," especially from growth driven by data centers.

The Report on Evaluating U.S. Grid Reliability and Security responds to President Trump's executive order from April, which DOE used to keep open power plants in MISO and PJM that were set to retire in May. Trump's order directed DOE to come up with a uniform method of studying resource adequacy. (See *Trump Seeks to Keep Coal Plants Open, Attacks State Climate Policies*.)

"This report affirms what we already know: The United States cannot afford to continue down the unstable and dangerous path of energy subtraction previous leaders pursued, forcing the closure of baseload power sources like coal and natural gas," Energy Secretary Chris Wright said in a statement. "In the coming years, America's reindustrialization and the AI race will require a significantly larger supply of around-the-clock, reliable and uninterrupted power.

The report argues that "absent decisive intervention," the grid will be unable to meet projected demand for manufacturing, re-industrialization and data centers, which make adversary nations control the future development of artificial intelligence, thus jeopardizing economic and national security.

The status quo of additional generator retirements and "less dependable replacement generation" is not consistent with winning the AI race or maintaining reliability, the report said. "Absent intervention, it is impossible for the nation's bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens."

The report estimates an additional 104 GW are set for retirement by 2030, which is planned to be replaced by 209 GW, though only 22 GW of that is from "baseload sources." Retirements and load growth combined could lead to 100 times greater risk in power outages by the end of the decade, the report said.

Why This Matters

The report argues for intervention to avoid reliability problems by the end of the decade and comes in response to an executive order that already led to two orders from DOE delaying power plant retirements.

"Antiquated approaches to evaluating resource adequacy do not sufficiently account for the realities of planning and operating modern power grids," the report said. "At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude and duration of power outages; move beyond exclusively analyzing peak load time periods; and develop integrated models to enable proper analysis of increasing reliance on neighboring grids."

The report said it used a model based on NERC's Interregional Transfer Capability Study, which uses time-correlated generation and outages based on historical data. It looked at a range of projections for data center demand by 2030 from major projects and picked a midpoint of 50 GW, allocating it regionally based on a forecast from Standard & Poor's.

The report includes several models, including one with the 104 GW of retirements that are in line with NERC and Energy Information Administration projections, another without power plant closures and a scenario with replacement capacity.

The only regions that did not fail to meet reliability thresholds in the power plant retirement category were ISO-NE and NYISO, which are not expected to see additional data center growth. But every other region saw higher risks of outages in the closed power plant case. Even if all the power plants were to stay open, the report still found shortfalls in PJM, SPP and the Southeastern Electric Reliability Council.

The report found that at least 23 GW of new "perfect capacity" is needed to meet future demand, especially in ERCOT and PJM (particularly in Virginia and Maryland).

The report calculates unserved energy (USE) for different regions of the country based on its forecast supply and demand and found troublingly high levels of the metric in some regions for 2030.

"It should be noted that USE is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system," the report said. "Rather, it represents the unrealizable AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements and potential load growth. These numbers are used as indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need."

The report does not use common probabilistic measurements of resource, such as expected unserved energy (EUE) or loss of load expectation (LOLE), instead using deterministic equivalents.

The report was released midafternoon July 7, so most people had limited time to review it. Advanced Energy United Managing Director Caitlin Marquis said it appears to exaggerate the risk of blackouts and undervalues the reliability contributions of wind, solar and battery storage.

"We are working quickly to dig into the numbers to unpack how DOE reached its conclusions, but it's troubling that the report was not subject to public input and scrutiny, especially since the executive order that mandated it calls for it to be used to identify power plants that should be retained for reliability," Marquis said in a statement. "If the analysis is overly pessimistic about advanced energy technologies and the future of the grid, consumers will end up paying too much for resources we no longer need." ■

Trump Executive Order Targets Renewable Energy Tax Credits

By John Cropley

President Donald Trump issued an *executive order* July 7 targeting renewable energy tax credits as strongly as possible under the One Big Beautiful Bill Act.

The law accelerates to 2026 the phase-out of the large tax credits created by the Inflation Reduction Act of 2022 in line with Trump's strong opposition to renewables and support for fossil fuel. He signed it at a July 4 ceremony. (See related story, *Trump Signs Big Beautiful Bill into Law on Independence Day*.)

A giant cross and wind turbines dominate the skyline along Route 66 in Groom, Texas. | *Shutterstock*

The order, "Ending Market Distorting Subsidies for Unreliable, Foreign-controlled Energy Sources," directs Treasury Secretary Scott Bessent to determine and then take all actions needed to terminate 45Y and 48E clean energy production and tax credits for wind and solar facilities.

The OBBBA specifies construction start dates and safe-harbor provisions for the remaining period of eligibility for these tax credits, and Trump's order directs that these rules not be circumvented by eligibility manipulation.

Trump also directed prompt implementation of the bill's enhanced restrictions on foreign entities of concern. And he directed Interior Secretary Doug Burgum to look for and eliminate any codified forms of preferential treatment for wind and solar over dispatchable energy sources.

The reasons stated in a *White House fact sheet* are familiar speaking points for Trump and some of his Republican allies:

- Wind and solar are unreliable, denigrate the natural beauty of the American landscape and displace dispatchable energy, compromising the grid.
- Reliance on green subsidies threatens national security by making the U.S. dependent on supply chains controlled by foreign adversaries.
- Ending these massive taxpayer subsidies is vital to energy dominance, national security, economic growth and the fiscal health of the country.

Why This Matters

The order could be implemented in a way to increase the impact of the One Big Beautiful Bill Act.

Trump specifies that his order be implemented consistent with applicable laws. However, there may be some room for interpretation of the energy-related provisions of *the 870-page OBBBA*.

Investment analysis firm Jefferies in a note to clients earlier July 7 said the House Freedom Caucus sought a strict interpretation by the administration of the "beginning of construction" provisions during negotiations as a condition for support. It said the concern now is whether the Trump administration will attempt to "change the goal posts" for these safe harbor provisions.

The order directs the Interior and Treasury departments to report back within 45 days on their findings and the actions they have taken or planned. ■

Trump Nominates 4 to TVA Board of Directors

Board Lacks Quorum After Firing of 3 Biden Appointees

By John Cropley

President Donald Trump has nominated four people to serve on the Tennessee Valley Authority's board of directors.

The nine-member board is down to three members due to the Republican-controlled U.S. Senate's failure to act on President Joe Biden's three nominations in 2024 and Trump's firing of three sitting members in the spring of 2025.

It has lacked a quorum for the past three months.

The July 1 announcement by the White House offered no details about the background of the four men, whose terms would extend to mid-2028, 2029 and 2030. News reports and official websites indicate:

- Lee Beaman, of Tennessee, is a longtime Nashville businessman and Republican campaign donor.
- Mitch Graves, of Tennessee, is CEO of the West Cancer Center & Research Institute and a Memphis Light, Gas and Water Board commissioner.
- Jeff Hagood, of Tennessee, is a founding partner in the law firm that bears his name and a member of the Knoxville Sports Authority Board.
- Randall Jones, of Alabama, is an insurance agent who chairs the boards of Jackson State University and the Electric Board of Guntersville.

The TVA board last had nine members earlier in Biden's term.

Six Biden nominees were confirmed by the Senate in December 2022 and took their seats on the board in January 2023: Beth Geer, Bobby Klein, Michelle Moore, Bill Renick, Joe Ritch and Wade White.

Why This Matters

The move would realign leadership of the nation's largest public power provider at a time when electricity demand is growing.

A generator rebuild in progress at TVA's Watts Bar Nuclear Plant near Spring City, Tenn. | *TVA*

Renick now is the board chair. His term expires in May 2027. Klein and White remain on the board, with terms expiring in May of 2026 and 2027, respectively.

Trump fired *Moore* on March 27, *Ritch* on April 1 and *Geer* on June 10.

The other vacancies were created by the expiring terms of three appointees from Trump's first term: William Kilbride, Beth Harwell and Brian Noland. Biden nominated Harwell, Noland and Memphis City Council member Patrice Robinson to fill the vacancies, but the Senate did not bring the nominations to a vote.

Shortly before Trump began sacking board members, Tennessee's U.S. senators — Marsha Blackburn (R) and Bill Hagerty (R) — *authored an op-ed piece* in *POWER* magazine saying the TVA board lacked the talent, experience and gravitas needed to carry the weight of the task before it: helping drive a nuclear renaissance led by the United States.

They said the members appeared more like political operatives than visionary industrial leaders, called the TVA bureaucracy hidebound and suggested that retiring TVA CEO Jeff Lyash should be succeeded by an outsider.

Shortly after the op-ed was published, the *TVA board announced March 31* it had chosen TVA Executive Vice President Don Moul as the new CEO. The next day, Trump sacked Ritchie, eliminating any potential quorum for the board.

Blackburn and Hagerty *jointly praised the nominees* July 1 after Trump announced them: "These nominees are a strong departure from the Biden-era TVA board which failed to meet the moment. We urge colleagues to swiftly confirm President Trump's TVA board nominees to make certain the United States leads the world in next-generation nuclear and wins the global race for energy dominance."

Hagerty separately added: "President Trump's nominees must be confirmed quickly so they can get to work correcting the many errors and failed policies the Biden-era TVA board put into place."

The nation's largest public provider has no shortage of critics, including some who want it to move away from fossil and nuclear generation, not build more.

TVA recently added nearly 1,400 MW of gas-fired capacity in Kentucky and Alabama; is building or considering 5,500 MW of new dispatchable generation; and in May became the first U.S. utility to request a construction permit for a small modular reactor. ■

NRC Makes Series of Streamlining Changes

Expedited and Simplified Procedures Come in Wake of Trump Orders

By John Cropley

The Nuclear Regulatory Commission has taken multiple steps to speed and smooth the path forward for the U.S. nuclear power industry.

In two weeks, the NRC announced it has:

- changed policies to accommodate factory-built microreactors;
- reduced the hourly rate charged to advanced nuclear reactor applicants and pre-applicants;
- accelerated its review of a construction permit for an advanced reactor planned in Wyoming; and
- finalized a rule extending design certifications from 15 to 40 years.

NRC also extended the expiration date of the operating license of a South Carolina nuclear reactor from 2042 to 2062, giving it a potential 80-year lifespan.

President Donald Trump on May 23 issued a series of orders intended to ease and expedite development of new nuclear power generation. Among these was a *strongly worded directive* for reform of the NRC, its structure, its personnel, its regulations and its basic operations.

On July 2, NRC published the *design certification (DC) rule* in the *Federal Register*. It is using the direct final rule procedure because it considers the action to be non-controversial. The rule will take effect Sept. 15 unless "significant adverse comments" are received by Aug. 1.

The change pertains to the five reactor DCs now in effect, as well as future DCs and renewals. The 15-year period dates to 1989; NRC said time has shown too little operating experience accumulates in 15 years for review at time of renewal. Extending the window to 40 years will allow this to happen, NRC wrote, adding,

Why This Matters

The NRC actions may help facilitate expansion of the U.S. nuclear power sector.

The Nuclear Regulatory Commission has extended the operation lines of Dominion Energy's V.C. Summer Nuclear Station through 2062. | *Dominion Energy*

"it will reduce unnecessary burdens with no reduction in safety or security."

Also on July 2, NRC said it had moved forward to *no later than Dec. 31* its target date for completion of review of TerraPower's construction permit request for its Kemmerer Power Station Unit 1.

TerraPower subsidiary US SFR Owner submitted the application in March 2024. Before adopting the "more aggressive schedule," NRC had expected completion of its review no later than June 30, 2026.

The company seeks to build TerraPower's Natrium design near an existing coal-fired power plant in Kemmerer, Wyo. The facility would be rated at 345 MW; an energy storage system would boost maximum temporary output to 500 MWe. If it is built, it will need an operating license through a separate NRC application procedure.

On June 30, NRC announced renewal of Dominion Energy South Carolina's operating license for *V.C. Summer Nuclear Station Unit 1*.

The 966-MW pressurized water reactor in Jenkinsville, S.C., first was licensed to operate from 1982 through 2022. In 2004, NRC approved a renewal to 2042. This latest renewal will extend its license through Aug. 6, 2062.

The *Nuclear Energy Institute's database* indicates this is the furthest-reaching license of any U.S. reactor other than the brand-new Plant Vogtle Unit 4, whose initial 40-year license extends to July 28, 2063.

There is widespread interest in expanding the aging U.S. nuclear fleet, but given the high cost and long time frame of new construction, operators are keen to keep existing facilities in service, uprate their capacity and even bring retired units back online.

Dominion said July 1 it has been conducting upgrades at V.C. Summer to ensure its longevity, including the recent replacement of the main transformer.

On June 24, NRC *amended the fees* it will charge applicants and licensees for fiscal 2025, as required by the ADVANCE Act of 2025. The hourly rate will be reduced from $318 to $148 effective Oct. 1.

The NRC is required to recover as much of its operating budget through fees as possible. Its fiscal 2025 budget authority is $944.1 million; it expects to recover $205.4 million through service fees and $603.4 million through annual fees.

On June 18, NRC announced three policy decisions to *expedite deployment of microreactors* — reactors built, fueled and tested at a factory that would generate 1% or less of the output of a large plant such as V.C. Summer. Under the changes:

- A factory-fabricated microreactor can be loaded with fuel at the factory under NRC license if it has features to prevent a nuclear chain reaction.
- Also, such a reactor can be excluded from "in operation" status.
- Finally, NRC staff can authorize testing of a microreactor at the factory before it is shipped to its operating site.

NRC said it had directed staff to continue other efforts focused on microreactors in compliance with the ADVANCE Act and the executive orders. ■

CESA Report Examines State Approaches to Meet Rising Power Demand

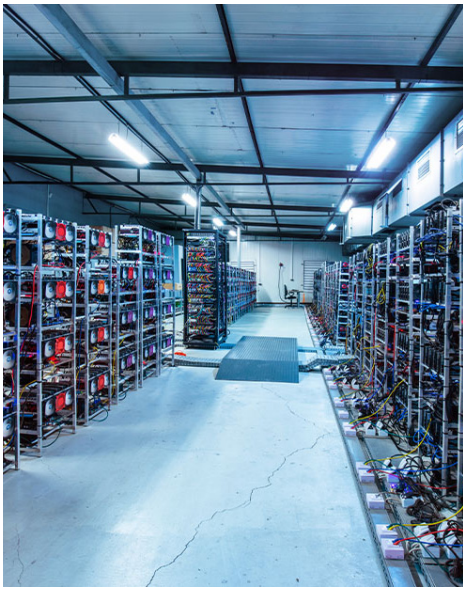
By James Downing

The Clean Energy States Alliance released a *report* July 2 highlighting how states are tackling the rise in electricity demand, which varies based on factors such as the scale of demand growth they face and their geography.

About 80% of national data center load in 2023 was in 15 states, but the growth is concentrated in Virginia, with the largest collection of data centers in the world that account for a quarter of statewide electricity consumption. Other states expecting to see significant demand growth from data centers in the coming years are Georgia, Texas, Pennsylvania, Indiana, Ohio and the Carolinas.

Demand from manufacturing is expected to rise in the Midwest (both PJM and MISO), Southeast and West, while electrification is going to drive demand growth in California, New York and New England.

"A big challenge facing states is uncertainty around load forecast projections," the report said. "The future of artificial intelligence and cryptomining, changes in state policy around electrification and clean energy, and the impact of federal policies on domestic industry and manufacturing all contribute to uncertainty. Additionally, big data centers often scout multiple potential locations for potential development, thereby making it unclear to state regulators and utility planners if and where a particular data center will ultimately be built."



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Why This Matters

Load growth is a new reality for the power industry, but the report dives into the details on what different states are facing and how they plan on dealing with new demand.

Most states, especially those with strong climate goals, continue to expand renewable energy, efficiency and demand response, but those facing near-term growth are backing new natural gas capacity and delaying the retirements of older fossil plants. Many states are exploring nuclear generation, with utilities including it in their long-term plans.

Concerns about rising costs from higher demand have led legislatures, regulators and utilities to develop large-load tariffs, promote data center efficiency and limit cost shifts among different customer classes.

The different drivers of load growth have their own demand profiles, which affects how they impact the grid and how state regulators and others need to address them.

Data centers generally are less flexible than most demand, but tech firms can shift computing demand around to different locations, and cryptomining facilities are price sensitive. But their usage is unpredictable, leading to forecasting challenges.

Industrial load tends to be higher during the workday, but process heat electrification and industrial-scale storage could help some facilities become more flexible.

Electrification load will tend to peak in the morning before people go to work and then again in the late afternoon/evening. In northern climates, such as New York and New England, electrification will shift the grid to having its overall peak in the winter.

"Transportation electrification's load shape will also vary to some degree," the report said. "Residential or commercial overnight charging will peak at night, while public fast EV chargers will likely peak during the day."

An analysis from RMI estimates that to meet the growing demand, about 94 GW of new natural gas capacity is planned to come online by 2035, 34 GW more than had been planned at the end of 2023. Renewables also are expected to grow, but the utility sector now plans to build 40 GW more natural gas than wind and solar by 2035, when just a couple years ago the planned new capacity for both was even.

Dominion Energy plans to build 5.9 GW of new gas by the end of the 2030s; Duke Energy has been approved to add 3.6 GW; and Southern Co.'s Georgia Power won approval for another 1.4 GW of gas this decade. Lawmakers in Maryland passed legislation to fast track a new gas plant, and those in Texas identified 17 gas-fired projects for state-backed loans.

About 9,100 MW of older capacity is expected to see its life extended because of demand growth, which includes two coal plants in West Virginia benefiting from new transmission planned to serve data centers in Virginia.

"Even New York, a state deeply committed to climate action, delayed the retirement of gas peaker plants in late 2023 due to reliability concerns and growing demand," the report said.

The federal government also has started to issue orders keeping coal plants open, which was anticipated by some in the industry: Duke Energy said it would revisit its plans to retire its coal plants just days after President Donald Trump won the 2024 election.

Using fossil plants to deal with the higher load clashes with climate policies in some states, such as Virginia and North Carolina, the report noted. ■

FERC Updates Environmental Review Process in Line with Trump Order

By James Downing

FERC on June 30 changed its regulations implementing the National Environmental Policy Act (NEPA) in compliance with President Donald Trump's *Executive Order 14154*, "Unleashing American Energy" (*RM25-11*).

Trump ordered the Council on Environmental Quality to rescind its regulations implementing NEPA; FERC's action eliminates references in its own rules to those now-defunct regulations.

"We will continue to ensure our environmental reviews are legally durable so projects stand up in court and get built," FERC Chair Mark Christie said in a statement. "Thanks to the leadership of President Trump, our new staff guidance on NEPA will inform all interested parties on our process and should be a useful tool in making the permitting process more efficient and transparent."

Enacted in 1970, NEPA established the CEQ and required all federal agencies, including FERC, to craft environmental assessments (EA) and environmental impact statements (EIS) that evaluate their actions' effects on the environment. Trump's Day 1 executive order repealed one issued by President Jimmy Carter in 1977, *Executive Order 11991*, which made CEQ the lead agency to develop the process agencies should follow to comply with NEPA and to manage conflicts between agencies over their responsibilities.

The CEQ's *authority to write regulations* was rescinded in November 2024 by the D.C. Circuit Court of Appeals, which found NEPA did not provide it. In his order, Trump directed the CEQ to instead provide guidance on how each agency should update their environmental review processes.

The details on how FERC's process will change are laid out in a *manual* prepared by its staff. The manual includes details on how staff will determine what actions are subject to NEPA's requirements and the level of review required by the law. It describes how staff will "ensure that relevant environmental information is identified and considered early in the process in order to support informed decision-making" and "conduct coordinated, consistent, predictable and timely environmental reviews while cutting unneeded burdens and delays."

FERC's D.C. headquarters | © RTO Insider

Why This Matters

FERC laid out how it will conduct its environmental reviews under NEPA now that the White House CEQ's regulations have been rescinded.

The manual spends several pages describing exclusions from the NEPA process and then explains that if a project is found to have a foreseeable effect on the quality of the human environment, staff will craft an EA. The text of the assessments is not to exceed 75 pages (not including citations or appendices with data such as scientific tables or statistical calculations).

Staff will have a year to prepare the assessment, with the deadline starting when hydropower projects are issued a Notice of Intent to Prepare an Environmental Assessment, or when natural gas projects get issued a Notice of Schedule. The assessment will determine whether an EIS, which is required when a project's environmental impacts cannot be mitigated, is needed.

The EIS process will include the chance for other interested parties to make comments on the proposed infrastructure and any NEPA mitigations required. EISes are to be limited to 150 pages of main text, with actions of "extraordinary complexity" getting up to 300 pages.

The deadline for an EIS will be two years, but staff can get extensions if that schedule proves not possible to meet. ■

WRAP Participants Find Value in Program's Nonbinding Phase

RA Effort's Challenges in Going Binding 'Prove out' Reliability Issues Facing West, OPUC Chair Says

By Elaine Goodman

Even in its nonbinding phase, the Western Power Pool's Western Resource Adequacy Program (WRAP) has been a valuable tool for working toward resource adequacy goals, program participants said.

"We are really finding that the nonbinding phase is increasing our likelihood of success in the future," said Camille Christen, resource acquisition, planning and coordination manager at Idaho Power.

Christen's comments came during an Oregon Public Utility Commission summer readiness workshop June 24 in which WRAP was one topic of discussion.

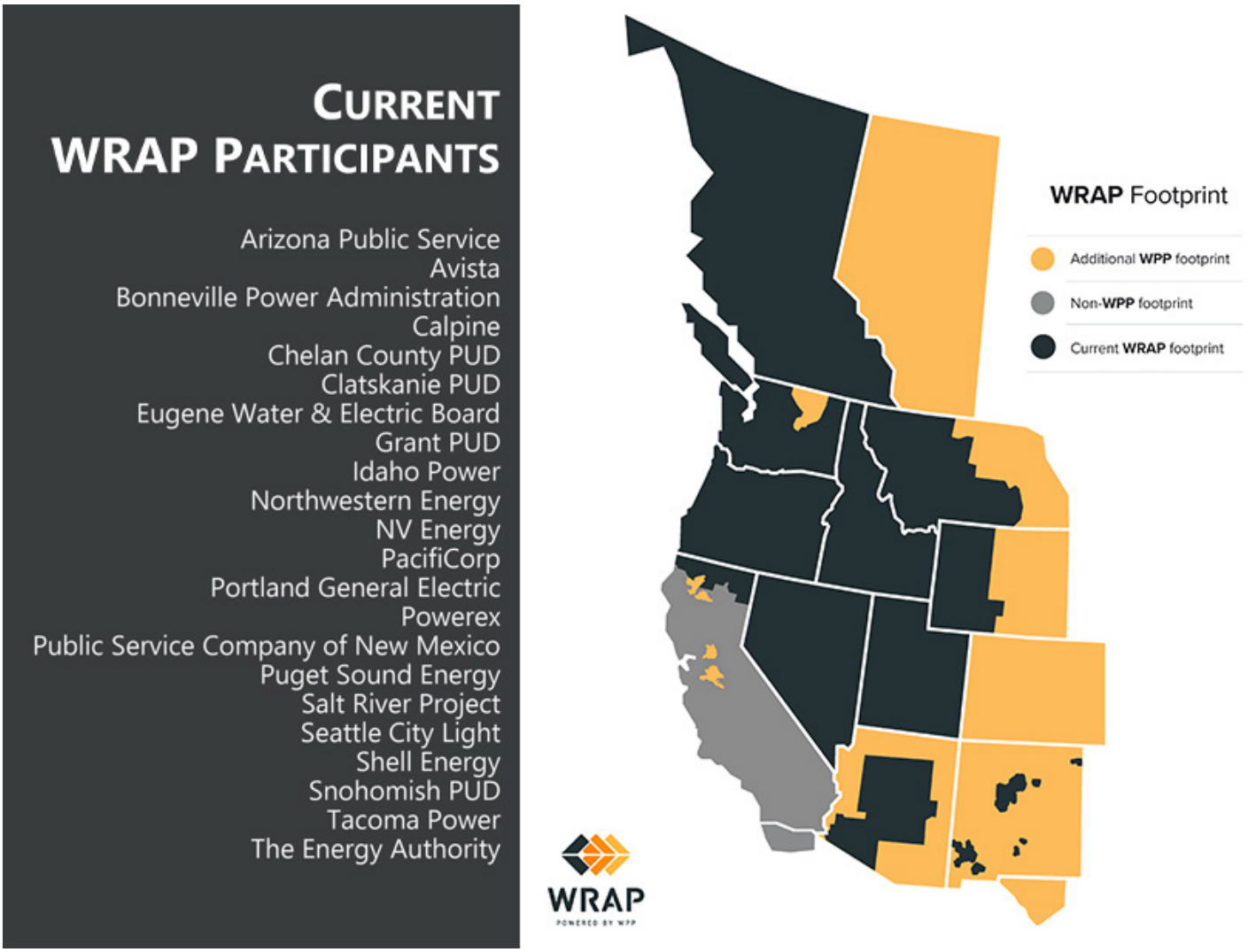
Why This Matters

Utilities across the West are facing headwinds in achieving regional resource adequacy, such as extreme weather and faster-than-expected load growth.

Idaho Power's WRAP capacity requirement, which consists of a load forecast plus planning reserve margin, was about 4,100 MW for summer 2025.

Idaho Power did not meet the forward-showing requirement, Christen said, despite its combination of existing and new resources and demand response programs. The utility is now working to resolve the deficiency.

Idaho Power fared better in meeting its internal 1-in-20 forecast of peak summer demand, which is about 4,000 MW. The utility has sufficient firm resources and contracts, including market purchases, to serve load. Idaho Power hit its all-time system peak of 3,793 MW in summer



The Western Resource Adequacy Program (WRAP) is in a nonbinding phase. | *WPP*

2024.

Christen noted differences between Idaho Power's internal modeling and the WRAP model, which is based on regional inputs. Assumptions also vary regarding resource contributions, and the timing of the two analyses differs.

WRAP's nonbinding phase has provided transparency into regional planning and aggregated resource position, she said. Participants are also gaining experience on the operational side of the program.

In a separate presentation at the OPUC meeting, Dee Outama, senior director of power operation at Portland General Electric, said the utility has enough resources to meet an internal target: a 1-in-2 peak plus a 9% planning reserve margin and 3% contingency. PGE is also in compliance with WRAP metrics for the summer, he said.

In response to a request from *RTO Insider*, WPP declined to provide details on how many WRAP participants have been meeting forward-showing requirements during the nonbinding phase.

Binding Phase Penalties

Western Power Pool launched the WRAP in response to industry concerns about resource adequacy in the West.

Under the program's forward-showing requirement, participants must demonstrate that they have secured their share of regional capacity needed for the upcoming season. Once WRAP enters its binding phase, participants with surplus must help those with a deficit in the hours of highest need.

The binding phase also includes penalties for participants that enter a binding season with capacity deficiencies compared with their forward showing of resources promised for that season.

In 2024, the binding phase was postponed by one year at the request of participants, who said they were facing challenges including supply chain issues, faster-than-expected load growth and extreme weather events that would make it difficult for them to secure enough resources and avoid penalties. The binding phase is now expected to start in summer 2027. (See *WRAP Members Vote to Delay 'Binding' Phase to Summer 2027*.)

"What's fascinating about the challenges that the WRAP is facing in going binding is they sort of prove out that there is a reliability challenge — that in fact folks are short," OPUC Chair Letha Tawney said during the meeting. "And it's hard to dig out of that hole in a time frame in the face of all the other headwinds."

The WRAP's first nonbinding forward showing season was winter 2023/24; the program's fifth forward showing, for winter 2025/26, is now underway.

And plenty is happening during the nonbinding phase, according to Michael O'Brien, WPP's senior policy engagement manager for the WRAP, who gave a presentation during the OPUC meeting.

"[Participants] are giving data to SPP, the program operator," O'Brien said. "They are going through the forward showing. They are being let know … where they are deficient in their planning."

Building Consensus

Another WRAP participant that has found the program beneficial thus far is Arizona-based Salt River Project.

"SRP sees significant value in WRAP, as it has provided a regional forum to discuss resource adequacy in the West and how to best address the adequacy challenges posed by load growth and changes to the resource mix," SRP spokesperson Jennifer Schuricht told *RTO Insider*.

In addition, WRAP has built consensus around a set of reliability metrics for the region, "which will be increasingly important as the resource mix changes," Schuricht said in an email.

SRP is on track to fully meet WRAP forward-showing requirements when the program becomes binding, she said. ■

FERC Again Rejects SDG&E Bid for RTO Adder

By Henrik Nilsson

FERC has denied San Diego Gas & Electric's challenge of a commission order rejecting the utility's request for an RTO adder to its transmission rates based on its participation in CAISO, saying SDG&E is ineligible for the adder under California law.

FERC found that SDG&E failed to show its participation in CAISO is voluntary, a condition for receiving the RTO adder, stating a 2022 California law requires electric utilities to join and remain members of CAISO, allowing them to leave only with the California Public Utility Commission's approval. (*ER25-270*)

Investor-owned utilities Pacific Gas and Electric and Southern California Edison joined SDG&E in challenging FERC's order.

"We continue to find that SDG&E's participation in CAISO is not voluntary," FERC's July 2 order stated. "Section 362(c) of the California Public Utilities Code provides that, '[c]onsistent with Section 851 and the [CPUC's] regulation of transfers of operational control of electric facilities, an electric corporation subject to [the transfer order] ... shall participate in [CAISO].' California IOUs do not dispute that SDG&E is subject to the transfer order. Therefore, the plain meaning of section 362(c) requires SDG&E to participate in CAISO."

In a separate but related order, FERC also affirmed a previous decision that SDG&E must refund adders with an effective date of June 1, 2019.

The decisions stem from a broader FERC order issued in December 2024 in which the commission partly accepted SDG&E's proposed formula rate and recovery of costs associated with transmission facilities. But FERC also rejected the utility's request for an adder and affirmed that decision July 2.

| Shutterstock

SDG&E proposed a base return on equity of 11.75% and an adder of 50 basis points for participating in CAISO — for a total ROE of 12.25%.

RTO adders are provided through federal ratemaking as a way for FERC to incentivize utilities to join RTOs or ISOs. However, to be eligible for the adder, utilities must show that participation in an RTO or ISO is voluntary and not mandated by state law.

Disputes around whether to allow California investor-owned utilities to recover an incentive for participating in the ISO have been ongoing. (See *Citing California Law, FERC Rejects PG&E Request for RTO Adder*.)

In a 2020 case involving PG&E, FERC rejected CPUC's argument that PG&E was ineligible for the RTO adder because participation in CAISO was mandatory. FERC ruled that, based on California law, the utility's participation in the ISO was voluntary and that it could decide unilaterally to leave. (See *FERC Rejects RTO Incentive Adder Rehearing*.)

But in September 2022, California amended its public utilities code to mandate participation in CAISO, with the ability to leave only with CPUC approval. Following this, FERC in December 2023 issued a decision holding that PG&E no longer was eligible for the RTO adder.

In the underlying case involving SDG&E, the San Diego-based utility told the commission it believed FERC wrongly ruled against PG&E in 2023 and had appealed the decision to the U.S. Court of Appeals for the Ninth Circuit.

According to the FERC July 2 order, the IOUs argue the CPUC code contains ambiguous language that allows them to leave CAISO, making their participation voluntary.

But FERC disagreed, instead finding "Contrary to California IOUs' view, Section 362(c) mandates participation and does not address withdrawal at all."

"While California IOUs argue that passages in the formula rate order and PG&E adder order suggest otherwise, the commission clarified in the PG&E adder rehearing order that Section 362(c) does not provide for withdrawal subject to CPUC approval," the order stated. "To the extent the formula rate order leaves any ambiguity, we clarify that Section 362(c) does not provide for withdrawal." ■

Why This Matters

The ruling is the latest in the dispute in California over RTO adders that has gone on for years.

PNM Signs Agreement to Join CAISO's EDAM

New Mexico Utility Cites 'Substantial Benefits' of Participating in Day-ahead Market

By Elaine Goodman

Public Service Company of New Mexico has made it official: The utility signed an implementation agreement to begin participating in CAISO's Extended Day-Ahead Market in fall 2027.

The move, which PNM announced July 1, also triggers Step 1 of the West-Wide Governance Pathways Initiative, an effort to create greater independence in the governance of CAISO's regional markets.

Under that change, the Western Energy Markets (WEM) Governing Body now has primary decision-making authority over market rules for the Western Energy Imbalance Market (WEIM) and EDAM, rather than joint authority with CAISO's Board of Governors.

PNM announced in November its intention to join EDAM rather than SPP's competing day-ahead market, Markets+. One factor in the utility's decision was its participation since 2021 in the WEIM, a real-time market that has provided PNM with nearly $170 million in benefits.

"The EDAM will integrate our state's renewable energy potential while helping us continue to serve our customers with clean and reliable service at the lowest cost," PNM CEO Don Tarry said in a statement.

PNM is the seventh entity to formally commit to joining EDAM. The others include PacifiCorp and Portland General Electric, which will begin participating in the market in 2026. The Los Angeles Department of Water and Power and the Balancing Authority of Northern California, which includes the Sacramento Municipal Utility District, signed agreements to join in 2027.

And in May, the Turlock Irrigation District and the Imperial Irrigation District (IID) signed implementation agreements formalizing their commitment to join EDAM. IID will also join the WEIM, in which Turlock already participates. (See *Turlock Irrigation District to Join EDAM in 2027* and *Imperial Irrigation District Inks Agreement to Join CAISO Markets*.)

While PNM's commitment to join EDAM is no surprise, it gives the CAISO market a solid foothold in a region rich with wind resources California seeks to tap to meet its ambitious clean energy goals.

Why This Matters

While PNM's commitment to join EDAM is no surprise, it gives the CAISO market a solid foothold in a region rich with wind resources California seeks to tap to meet its clean energy goals.

"PNM's participation strengthens the foundation of a more interconnected, reliable and cost-effective regional electricity market," CAISO CEO Elliot Mainzer said in a statement.

BHE Montana, NV Energy, Idaho Power and Arizona G&T Cooperatives have indicated they're leaning toward EDAM.

Step 1 Triggered

The CAISO Board of Governors and the WEM Governing Body last August approved a proposal in which Step 1 of the Pathways Initiative would be triggered when entities meeting certain size and geographic diversity criteria signed EDAM implementation agreements. (See *CAISO, WEM Boards Approve Pathways 'Step 1' Plan*.)

With PNM's commitment to EDAM, utilities outside the CAISO balancing authority area that have signed EDAM implementation agreements represent a load equivalent to 75% of load in the CAISO balancing authority area — exceeding the 70% threshold to trigger Step 1.

And the EDAM commitments have enough geographic diversity because they include non-California entities from the Northwest and the Southwest, CAISO management said in a July 1 *certification notice*.

The Step 1 provisions also include a dispute resolution process. If the CAISO board and WEM Governing Body can't agree on a particular proposal, they may file two proposals with FERC as "co-equal" options in a single document.

Another change enhances language in the WEIM and EDAM governance charter about considering the public interest.

"Independent governance of the Western Energy Markets is crucial for establishing a strong day-ahead energy market that will maximize consumer benefits," Stacey Crowley, CAISO's vice president of external affairs, wrote in a July 1 *blog post*.

Step 1 is seen as a temporary measure until Step 2 of the Pathways Initiative can be implemented.

Step 2 calls for transferring market governance to an independent "regional organization," a move requiring changes to California law. Senate Bill 540, which would implement Step 2, was passed by the state Senate on June 4 and is now being considered in the Assembly. (See *'Pathways' Bill Passes California Senate on 36-0 Vote*.)

'Substantial Benefits'

PNM's announcement of its intent to join EDAM followed the New Mexico Public Regulation Commission's release of a set of "guiding principles" for utilities to use in selecting a day-ahead market. (See *PNM Picks CAISO's EDAM*.)

"PNM continues to believe joining EDAM will offer substantial economic and operational benefits to New Mexico customers," Kelsey Martinez, PNM's director of regional market and transmission strategy, wrote in a June 30 *filing* with the PRC.

"This decision reflects a careful review of commission principles, including analysis of customer benefits, efficient resource dispatch and effective stakeholder engagement," she added.

Martinez also noted in the filing that CAISO imposes no exit fees if an entity decides to leave EDAM. The entity may then return to WEIM-only participation or leave both the WEIM and EDAM.

Martinez said PNM would provide regular updates to the commission on its EDAM integration. ■

FERC OKs Abandoned Plant Incentive for Calif. Offshore Wind Tx Developer

Move Should Reduce Financing Risks for New Humboldt Transmission Lines

By David Krause

California's first offshore wind project got a boost June 30 when FERC granted CalGrid an abandoned plant incentive for a set of OSW-related transmission projects in the Humboldt County area.

The incentive provides some financial protection to CalGrid should its proposed projects be cancelled (*ER25-563*).

Both are reliability projects and were approved by CAISO in May 2024 as part of CAISO's 2023/24 transmission planning process. In May 2025, CAISO selected CalGrid's parent company Viridon to finance, construct, own, operate and maintain both lines. (See *CAISO Chooses Viridon to Develop Humboldt OSW Transmission Projects*.)

Viridon California is a subsidiary of Viridon Holdings, a portfolio company of Blackstone.

The first project, the NH-C project, includes about 200 miles of new 500-kV transmission line, which will connect a new substation in Humboldt to a new substation in Collinsville. The second, the NH-F project, includes about 100 miles of new 500-kV transmission line from the new substation in Humboldt to a substation on Fern Road in Shasta County.

"The projects face risks beyond CalGrid's control that could lead to the projects' abandonment," the commission wrote in the order. "We find that CalGrid has demonstrated a nexus between its requested incentive and its planned investment, and that CalGrid has tailored its incentive rate request to its identification of risks and challenges associated with the projects."

The abandoned plant incentive would be available to CalGrid for 100% of prudently incurred costs expended on and after the date of the order if the projects were abandoned for reasons beyond CalGrid's control, FERC wrote.

The projects face significant risks that "could result in their cancellation," CalGrid said in its filing. Those include regulatory approval uncertainties and CalGrid's lack of building experience — i.e., the projects will be the first transmission lines that CalGrid has built.

Existing transmission lines in Humboldt County | *CEC*

Why This Matters

FERC's approval of the abandoned plant incentive for the Humboldt County lines should help shore up California's effort to build offshore wind.

The abandoned plant incentive will help CalGrid attract financing "by removing the risk that lenders and investors may have to bear prudently incurred costs if the projects are canceled for reasons outside of CalGrid's control," the order says.

The projects will cost up to $4.1 billion and are expected to be completed by 2034.

In 2006, FERC issued Order No. 679, which allows applicants to request incentive rate treatment for transmission infrastructure investments that ensure reliability or reduce the cost of delivered power by reducing transmission congestion. CalGrid said the Humboldt projects meet this requirement because they were approved as part of CAISO's regional planning process. CalGrid also said the projects are beneficial to ratepayers and promote FERC's pro-competitive policies.

In the order, FERC Chair Mark Christie dissented "for reasons consistent with my previous statements on the subject." In a *May 13 order*, Christie said, "As I have said repeatedly over the past four years, it is long past time for this commission to do its job of protecting consumers by cutting back on its unfair practice of handing out 'FERC candy' without any serious consideration of the impact on consumers already struggling to pay monthly power bills." ■

'Islanded' BAs Face Tough Choices in Western Market Future, Experts Say

Pacific Northwest Entities Particularly Impacted, Analysts Contend

By Henrik Nilsson

Although one aim of Western day-ahead markets in the West is to fix a fragmented transmission landscape, some islanded entities will have a tough time navigating seams issues likely to arise as markets take shape, analysts at Aurora Energy Research said during a July 1 webinar.

The webinar, titled "*Western Regionalization: EDAM, Markets+ and RTO West*," covered the separate initiatives launched by SPP and CAISO to create day-ahead markets in the West.

One of the issues discussed was the market seams likely to arise as entities enter either SPP's Markets+ or CAISO's Extended Day-Ahead Market (EDAM). Seams arise from the differing policies and separate dispatch between neighboring markets, resulting in additional costs for transferring energy across the boundary.

The Western Interconnection contains 38 balancing authorities serving approximately 82 million customers across 14 states, Canada and Mexico. Though BAs operate under an Open Access Transmission Tariff, transferring power through the footprints in the West can still be "incredibly complex given the vast geographic spread and sheer fragmentation of this transmission landscape," said Gaurav Sen, market lead at Aurora.

"That legacy fragmentation is part of that impetus driving BAs towards Western regionalization," Sen said.

Despite those efforts, seams will remain as BAs have signed with different day-ahead markets, creating non-contiguous footprints. Seams and wheeling costs will have a particular impact on the cost of energy in the Pacific Northwest, according to Susanna Lofvander, data analyst at Aurora.

With the Bonneville Power Administration sitting on approximately 22 GW of hydro resources and having the second-largest transmission mileage of any BA in the West, BPA is a crucial resource for its neighboring BAs, Lofvander noted.

"BPA has signed an implementation agreement with Markets+, and in doing so, they have islanded a couple of their neighboring balancing authorities, which have previously committed to EDAM, namely Seattle City Light and Portland General Electric," Lofvander said. (While Seattle City Light has expressed that it heavily favors EDAM, it has not yet formally committed to the market.)

Seattle City Light and PGE are surrounded by territories that have committed to Markets+, and if the two utilities want to continue to import from BPA, they will have to pay seams costs or wheeling costs from EDAM territories, which will have an upward pressure on energy costs, according to Lofvander.

"This is particularly impactful for these two regions, as they sit on two large load centers, namely Seattle and Portland, that are expected to have significant population growth and electrification that will continue to drive load," Lofvander said.

'Comprehensive and Inclusive'

BPA staff has argued the agency is not solely responsible for creating seams and has consistently expressed confidence in SPP and the agency's ability to manage energy transfers across seams based on its own history of doing so within the Northwest. This point was most recently reiterated by BPA Administrator John Hairston during a keynote at the Western Conference of Public Service Commissioners on June 2. (See *Day-ahead Issues Could Take Years to Resolve, BPA Staff Says* and *BPA Chief to Regulators: Industry Needs 'New Planning Paradigm'*.)

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"BPA completed one of the most comprehensive and inclusive public processes in the West regarding its policy direction toward Markets+," agency spokesperson Nick Quinata told *RTO Insider* in an email. "BPA stands by its analysis and does not agree with the assertion that any utility is 'islanded' because of BPA's policy direction. BPA will work collaboratively with all neighboring utilities to proactively address and manage any seams."

However, the Pacific Northwest is not the only region where potential seams could cause headaches. A similar situation is expected in the Desert Southwest, specifically in Arizona and New Mexico, "where some of these territories are surrounded by other balancing authorities that are committed to the opposing day-ahead market and therefore are exposing themselves to those wheeling costs and seams costs," Lofvander said.

Proponents of both Markets+ and EDAM each have argued that their respective preferred market choice provides a better solution for resolving seams. (See *Seams Concerns Won't Drive Day-ahead Market Decision, BPA Says*.)

City Light asked for more details about the webinar before responding to a request for comment. PGE did not respond in time for publication of this article. ■

Why This Matters

The issue of market seams continues to stir debate as the West inches closer to splitting into two day-ahead markets.

Texas Supreme Court Dismisses Bulk of Winter Storm Uri Claims

Court Rejects Customer Complaints of Nuisance, Negligence

By Tom Kleckner

The Texas Supreme Court has ruled against residents and businesses who sued utilities after the deadly February 2021 winter storm known as Uri, saying they did not adequately prove the companies were intentionally negligent in causing widespread power blackouts.

In a June 27 order, the high court ruled the plaintiffs did not provide enough evidence to show Oncor, CenterPoint Energy and AEP Texas were "purposely negligent" or caused a nuisance when they were ordered to cut power as ERCOT struggled to meet overwhelming demand following Winter Storm Uri (*24-0424*).

Writing for the court's unanimous decision, Justice Debra Lehrmann dismissed the claims of intentional nuisance, saying the plaintiffs did not allege sufficient facts to survive a motion to dismiss. She held that the plaintiffs, "as a matter of law, cannot allege" that the utilities "created" or "maintained" a nuisance.

"The alleged 'nuisance' here is prolonged freezing temperatures during Winter Storm Uri," Lehrmann wrote. "The allegations do not suggest that the utilities created or exacerbated the cold temperatures or affirmatively maintained them. Rather, the plaintiffs complain that the utilities failed to adequately respond to and mitigate the harm caused by those temperatures. That is not a basis for an intentional-nuisance claim."

Why This Matters

The Texas Supreme Court's decision dismisses most of customers' complaints about utilities' load shedding during the deadly February 2021 winter storm. However, it does give an opportunity for plaintiffs to replead their gross-negligence claims in an amended petition.

Lehrmann also held that the plaintiffs' arguments "do not sufficiently allege gross negligence." However, she wrote they should "have an opportunity to replead the gross-negligence claims."

The court ordered the Harris County multidistrict litigation (MDL) court to dismiss the intentional-nuisance claims with prejudice and to provide the plaintiffs an opportunity to replead their gross-negligence claims in an amended petition.

Thousands of customers filed hundreds of lawsuits against electricity companies in the wake of Uri's outages, which lasted up to 80 hours for some Texans. The cases, alleging negligence, gross negligence, nuisance and other claims, were consolidated into an MDL proceeding.

The storm's freezing temperatures knocked more than 34 GW of generation offline, bringing the Texas Interconnection within minutes of total collapse. The ensuing outages caused billions of dollars in damages, bankrupted electric companies and killed hundreds of Texans.

The 14th Court of Appeals dismissed the negligence and strict-liability nuisance claims but allowed the gross negligence and intentional nuisance claims to proceed. The Texas Supreme Court heard arguments on appeal in February. (See *Texas Supremes Hear Arguments in Last Uri Case*.)

Oncor spokesperson Roxana Rubio said the company was pleased with the ruling in that it barred plaintiffs from pursuing six of the seven original causes of action alleged against it. She said the utility is confident the case will "ultimately be fully dismissed should the plaintiffs attempt to pursue an allegation of gross negligence under the strict limitations of this ruling."

"We continue to maintain that every action Oncor took during Winter Storm Uri was for the purpose of successfully preventing the collapse of the Texas grid," Rubio said in an email. "We recognize this does not lessen the anguish experienced by our customers and by Texans across the state during that time."

CenterPoint said it takes seriously "the privilege it has of providing safe and reliable electric service to its customers and communities." It said it implemented ERCOT's load-shed orders and "acted quickly to save the electric grid when demand exceeded supply."

"CenterPoint is confident that plaintiffs will be unable to support any claim for gross negligence," the utility said in a statement. "If plaintiffs replead, CenterPoint will continue to vigorously defend against plaintiffs' remaining claim in the trial and appellate courts."

AEP Texas declined to comment. ■

The Texas Supreme Court in Austin, Texas | © RTO Insider

IESO Seeking Feedback on Commercial HVAC Demand Response Program

By Michael Brooks

IESO plans to introduce its first electricity demand-side management (eDSM) program in 2026, focused on commercial HVAC systems during summer to lower peak demand as load grows in Ontario.

"HVAC loads in the commercial sector presents a significant opportunity for demand response," the ISO said in a *presentation* to stakeholders June 24. "Large commercial buildings, including offices, retail spaces and institutional facilities, account for a substantial portion of Ontario's peak demand, largely driven by HVAC loads during summer cooling season."

The ISO has numerous energy efficiency programs that mostly are focused on retrofitting buildings, collectively known as *Save on Energy*. It also allows DR resources to participate in its capacity market. The new program would be part of Save on Energy, and any aggregated loads participating would be barred from bidding into the market.

That's because capacity resources are expected to perform for at least half the year. (The "summer" half of the capacity year is defined as May 1 to Oct. 31.) However, certain large commercial facilities have capacity value only during the height of summer. The ISO is targeting 100 MW of curtailment in 2026 and 230 MW in 2027 from "resources" such as large retailers, office buildings, shopping centers, universities and municipal premises.

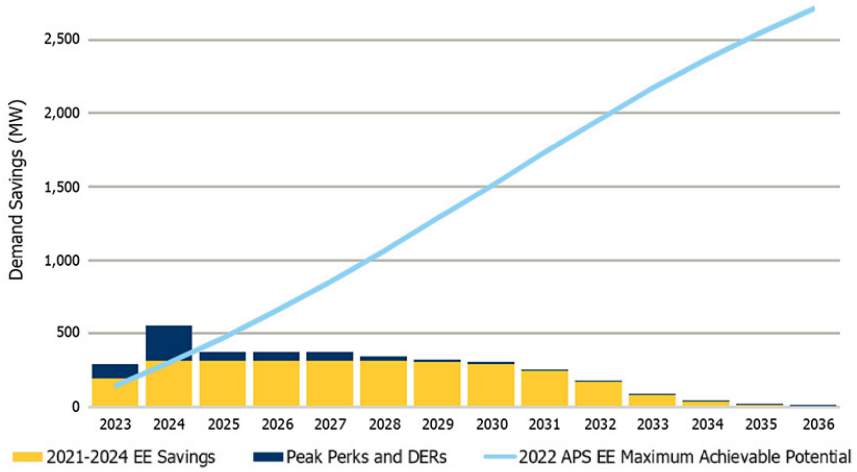
IESO plans to begin registering participants at the beginning of 2026 with a goal of beginning operation June 1 and running until Sept. 30. DR events would last up to three hours on business days only. Participants would be compensated by the end of the year based on the average megawatts curtailed and capacity prices for those four months.

The program is part of a larger eDSM *framework* funded through Ontario's Affordable Energy Act of 2024, which granted IESO $10.9 billion for the new program as well as expanding existing Save on Energy programs. As part of the initiative, the ISO also is considering programs to support distributed energy resource installation and additional incentives for new energy-efficient buildings.

IESO has allocated $1.8 billion for the first three years of the framework with goals of 900 MW in peak demand savings and 4.6 TWh in electricity savings.

The ISO used the June 24 presentation to go over aspects of the commercial DR program on which it is seeking *feedback* from stakeholders. IESO's Mohammed Yousif highlighted the ISO's proposed incentive structure: the summer capacity price ($/MW-day) multiplied by 92 (representing the 23 business days in each of the four months), with the resulting figure multiplied by the average demand reduction.

A stakeholder representing the University of Western Ontario, which participates in the capacity market as part of an aggregation, asked how compensation through the program would compare. Noting that "the HVAC program is not meant to compete with the capacity auction," Yousif said, "I think what we are leaning towards is … for the [program's] price to be aligned with the [auction] clearing price, but not more."



Electricity savings potential of current IESO energy efficiency programs | *IESO*

What's Next

Feedback is due July 8. IESO will provide its response July 29 and consult with potential aggregators and other commercial customers over August and September, with a goal of issuing rules for the program before the end of October.

Another stakeholder asked why the program was limited to HVAC. "I'm a bit confused … if the intention is to alleviate demand on the grid, why are we limiting it to HVAC loads when a lot of these buildings have good capabilities [such as] light dimming?"

Yousif answered that "there has been a lot of discussion" about widening the scope of the program after the first one or two years.

But others were not satisfied with this, with one saying, "It seems like you're adding a lot of rules … for something that doesn't really make any sense. You should just let people openly select their demand response technologies."

Yousif urged attendees to submit this feedback in writing and again suggested the program could open to other technologies if the ISO sees enough potential.

Feedback is due July 8. IESO will provide its response July 29 and consult with potential aggregators and other commercial customers over August and September, with a goal of issuing rules for the program before the end of October. ■

IESO Eyes New Tie-break Rules for November Capacity Auction

By Rich Heidorn Jr.

Bowing to stakeholder requests, IESO officials said they will implement a revised method for breaking capacity auction ties in time for the 2025 contest in November.

A tie-break occurs when two or more participants offer the same price for the last available quantity of capacity in a zone.

Under current rules, the ISO uses time stamps to select the bid submitted first, a method stakeholders have complained about for years.

IESO's Laura Zubyck, senior analyst for electricity resource development, said in a June 26 *webinar* that the ISO agreed to accelerate development of a new tie-break procedure in response to stakeholders' feedback that changing the rules for 2025 was a "top priority."

Resource	Offer Price ($)	Offer Quantity (MW)	Full/Partial	Step 1 Allocation (MW)
A	50	25	Partial	13.3
D	50	5	Full	5
F	50	40	Partial	13.3

Resource	Offer Price ($)	Remaining Offer Quantity (MW) After Step 1	Proportion (MW)	Step 2 Allocation (MW)
A	50	11.7	2.559375000000000	2.5
F	50	26.7	5.840625000000000	5.8
TOTAL	-	**38.4**	**8.4**	**8.3**

Resource	Offer Price ($)	Remaining Offer Quantity (MW) After Step 2	Time Stamp	Rank	Step 3 Allocation (MW)
A	50	9.2	11/27/2024 9:45:32 AM	1	0.1
F	50	20.9	11/27/2024 3:30:55 PM	2	0

IESO is proposing a three-step procedure for breaking capacity auction ties. | *IESO*

Revised Methodology

The new rules will create a multistep process that IESO said will be more equitable.

In the first step, the ISO will divide the remaining available capacity by the number of offers involved in the tie to determine an equal share of capacity per offer, rounded down to one-tenth of a megawatt.

For example, if there is 40 MW remaining to be allocated and three offers totaling 70 MW, the equal share is 40 MW divided by 3, or 13.3 MW.

Step 1: Resource D, which offered 5 MW, is allocated the full 5 MW because it is less than 13.3 MW. Resource A, which offered 25 MW, and Resource F, which offered 40 MW, each are awarded 13.3 MW, leaving 8.4 MW unallocated.

Step 2: The remaining tied partial offers are awarded proportional shares of the capacity remaining after Step 1. Resource A, which had 11.7 MW remaining in its offer after Step 1, is awarded 2.559 MW (rounded to 2.5 MW) and Resource F, which had 26.7 MW remaining, is awarded 5.84 MW (rounded to 5.8 MW). That leaves 0.1 MW to be allocated in Step 3.

Step 3: Offers are ranked by time stamp. Resource A, which filed earlier, is awarded the final 0.1 MW.

Allotments of Less than 1 MW

One wrinkle: ISO officials said the tie-break process could result in a total capacity allotment of less than 1 MW for a resource, which is not permitted by market rules.

In such a scenario, the resource that would be awarded an obligation of less than 1 MW will be eliminated, and the tie-break process will be repeated starting with Step 1.

For example, if four offers shared the same price for the final 3.9 MW and one would have been allocated only 0.9 MW, it would be eliminated, resulting in three equal allocations of 1.3 MW.

Multiple Constraints

ISO officials also discussed a situation in which multiple constraints are involved in a tie-break — for example, an intertie limit and a zonal limit — with the available capacity of one limit lower than the other.

The tie-break for the lower limit would be resolved first using the tie-break steps. The remaining capacity would be allotted to the remaining tied offers associated with the higher limit.

Next Steps

IESO asked stakeholders to provide *feedback* on the proposed rules by July 10. IESO's Technical Panel will begin considering the changes in July with a vote to post scheduled for September and board approval anticipated in October. The Nov. 26-27 auction will seek capacity for the periods beginning May 1 and Nov. 1, 2026, with results posted Dec. 4.

The ISO board also is expected to vote in August on rule changes to reduce unfulfilled capacity commitments by making it easier for participants to transfer their obligations and harder to buy them out. (See *IESO Seeks to Shore up Capacity Market*.) ■

Why This Matters

IESO stakeholders have complained for years that the current tie-break methodology is not equitable.

IESO to Expand Synchrophasor Data Requirements to Storage

By Michael Brooks

IESO proposes to update its synchrophasor data requirements to include storage resources as part of its effort to expand the use of phasor measurement units (PMUs) in Ontario.

Storage units rated at least 20 MVA, including aggregations, would be required to provide their voltage and current phasor measurements and frequency for all three phases. The same requirement would apply to units that are associated with or have the potential to impact a NERC interconnection reliability operating limit, regardless of size.

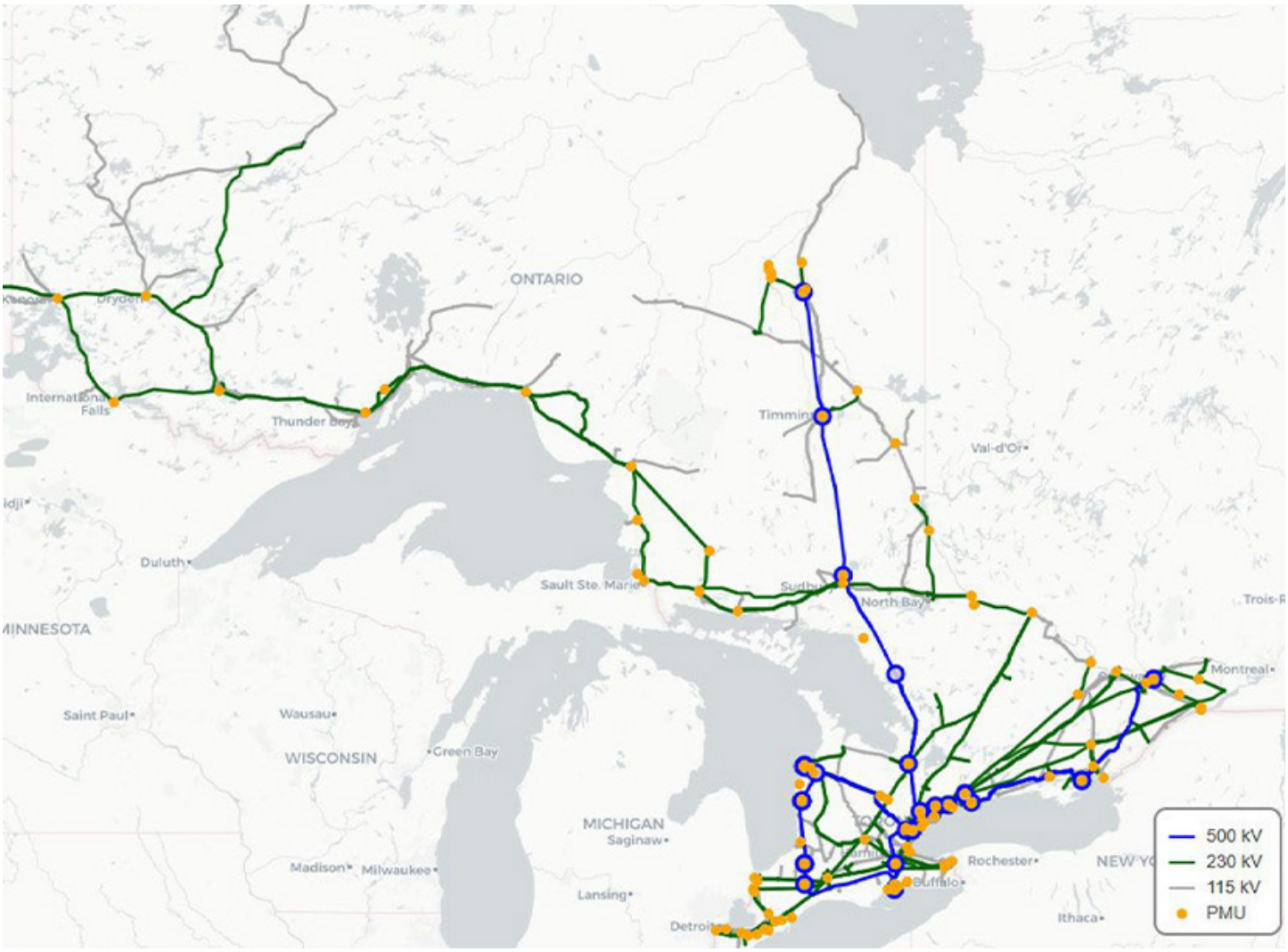
The data required would be the same as those provided by generators and transmission owners, but the ISO also proposes doubling the reporting rate — 60 samples per second — for all resources. Storage units also would need to provide phasor measurements for each phase sequence, unlike generation and transmission, which must provide data for only the positive sequence.

The number of PMUs grew exponentially in North America after the 2003 Northeast blackout. The American Recovery and Reinvestment Act of 2009 (the so-called "stimulus package") provided $4.5 billion for grid operators to deploy smart grid technologies, including PMUs. Utilities and RTOs installed more than 1,000 production-grade PMUs over the following five years.

But Ontario has lagged behind the U.S. The IESO proposal is part of a larger initiative to increase PMU usage throughout the province to more than 200. The requirements for generation and transmission went into effect at the end of 2024.

"This project will enable us to finally begin closing the gap between what our neighbors have been doing for some years before us and also adopt some new applications for our control room folks," Dame Jankuloski, IESO's lead power system engineer, said during a webinar June 26 to *present* the proposal.

Feedback on the proposal is due July 10, with the goal of Technical Panel approval by the end of the year and PMU registration beginning in early 2026. ■



IESO is targeting the deployment of 229 PMUs across Ontario. | *IESO*

Drought, Climate Drive Uncertainty on New England Imports from Québec

By Jon Lamson

In the spring, as questions swirled about potential Trump administration tariffs on electricity from Canada, power flows from Québec to New England declined substantially, causing some *concerns* that the tariff threat was causing Québec to limit power exports to the U.S.

While these concerns appear unfounded — the drop in imports likely was driven largely by low power prices in New England — the low import levels illustrate a series of growing challenges on both sides of the border.

Imports from Québec historically have played a significant role in the ISO-NE system, accounting for an average of about 11% of net energy for load in New England between 2015 and 2022. But net imports over tie lines with Québec have dropped drastically over the past two years, making up just over 5% of net energy for load in New England in 2024 and sitting at a similar level through the first four months of 2025, according to ISO-NE data.

The largest factor driving Québec's multi-year reduction of exports appears to be an extended drought, which began in early 2023 and has caused declining water levels in Hydro-Québec's major reservoirs.

"It's the third year of a deep drought," said Robert McCullough, principal of McCullough Research. Data collected by the firm indicate water levels of Hydro-Québec's largest reservoir systems have declined significantly since the start of 2023.

Hydro-Québec's exports also have been affected by a pair of looming, long-term power contracts the company signed with U.S. states: the 1,200-MW New England Clean Energy Connect (NECEC) project, anticipated to come online at the end of 2025, and the 1,250-MW Champlain Hudson Power Express transmission project, expected to come online in mid-2026. Both projects are intended to procure over 1,000 MW of baseload power on an annual basis from Hydro-Québec.

"When we talk about exports, an important firm energy commitment we have to take into account is the two new contracts that we will have with New York and Massachusetts," said Maxime Nadeau, senior director of system control and grid operations at Hydro-Québec.

Over the past two years, the company has reduced its allowed amount of non-firm exports to ensure it has enough water to meet all its long-term firm power commitments, Nadeau said.

Québec, like much of North America, faces its own load growth; Hydro-Québec's most recent electricity supply plan *forecasts* power demand to grow by 14% between 2022 and 2032. While the company has *announced plans* for major long-term investments in new generation, the impending addition of new export commitments could pose a challenge over the next few years if drought conditions persist.

Hydro-Québec's Manic-5 Reservoir on the Manicouagan River | *Hydro-Québec*

Why This Matters

Short- and long-term precipitation trends in Québec likely will have a significant effect on how much power New England will be able to import from the province.

Declining Water Levels

On the La Grande watershed in northern Québec, home to more than 17,000 MW of installed hydroelectric capacity, 2025 inflows are tracking between 2023 and 2024 levels, according to data from McCullough Research. Meanwhile, the Canadian Drought Monitor indicates that a significant portion of northern Québec is facing moderate drought or abnormally dry conditions, according to the May 31 *update*.

"We're having even lower inflows than we had last year," McCullough said. "If they go into a fourth year of drought, [Hydro-Québec] may be forced to reduce their external commitments."

Despite low water levels, representatives of Hydro-Québec expressed optimism that inflows will return to typical levels this year, bringing the region's reservoirs back to historical norms. The company has maintained it will have enough energy to meet all its firm commitments in the coming years.

"The very low inflows observed in 2023 and 2024 have had a lasting impact on 2025 overall levels," said Lynn St-Laurent, spokesperson for Hydro-Québec. "However, the combination of a revised production strategy and normal inflows should help restore water levels to more

typical values."

St-Laurent said it is normal for the region to experience fluctuating water levels and that the company has faced multi-year droughts on a similar scale in the past.

She stressed that "inflows remain around normal levels for 2025" and said it can be misleading to compare inflows at an isolated point in time, noting that "the low water availability of the last two years at La Grande was not due to weak spring runoff, but rather to low precipitation during the summer and fall of previous years."

Climate Impacts and Uncertainty

While it is difficult to pinpoint exactly how climate has affected the current drought and water levels, scientists expect precipitation variability — both over multiyear stretches and intra-year periods — to increase in Québec as the planet warms.

"We expect droughts to be more frequent and more persistent in the future, related to climate change," said Christopher McCray, climatologist at Ouranos, a climate research organization funded by the Québec government.

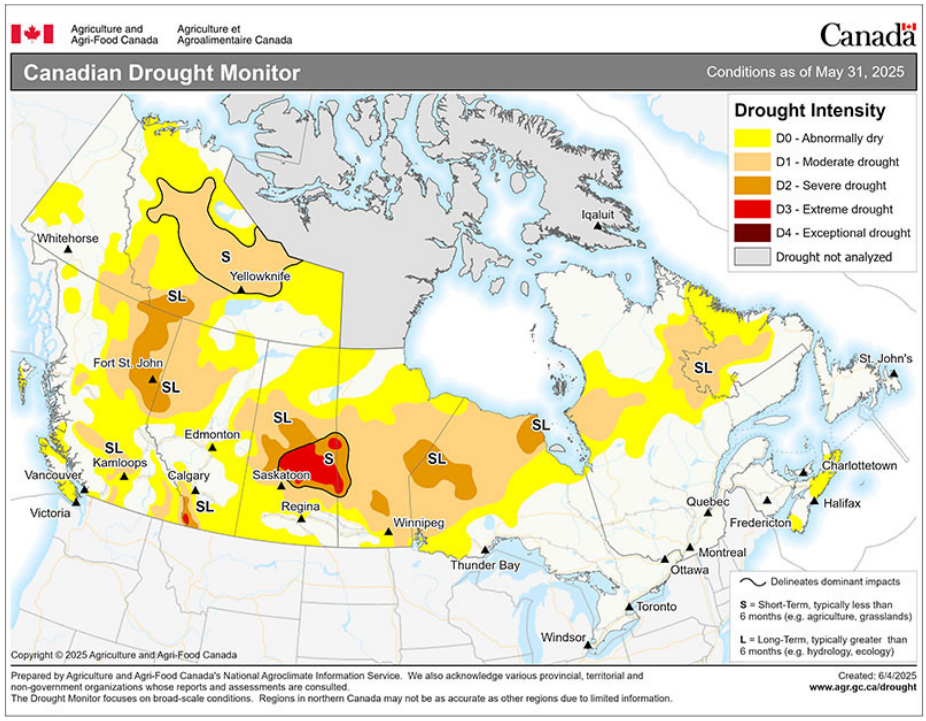
Although most studies indicate northern Québec will see increasing average annual precipitation, multiyear drought periods could create increasing challenges for water management, McCray said.

While Québec always has seen a fluctuation between dry and wet years driven by large-scale weather patterns, warming temperatures are "accentuating the effects of those patterns," McCray said.

"The same weather pattern that caused a drought 50 years ago, now it's a little bit warmer … and there's a greater capacity for evaporation than in the past," McCray said. "And so, the soil dries out, and that can cause a feedback loop that leads to a persistent period of dry conditions."

Hydro-Québec expects to see "more overall water supply in the northern part of the province," Nadeau said. "That's good news, because that's where we have all of our major main reservoirs."

He added that the company recently began working with experts on studies to better understand how climate change will affect inter-annual variability.



Canadian Drought Monitor, May 31 | *Agriculture and Agri-Food Canada*

Researchers also anticipate climate change will cause seasonal shifts in precipitation. Ouranos predicts average winter precipitation to increase and more frequently fall as rain. This likely would increase stream flows in the winter and move the spring high-runoff period earlier in the year.

McCray said there is more uncertainty around how climate change will affect overall summer precipitation but that there could be an increased "whiplash" between dry periods and extreme rainfall events within summer seasons.

While long-term scientific studies consistently forecast increased precipitation for the province, McCullough said the impact of climate change on the jet stream has created significant new challenges for forecasting precipitation and water levels.

"We've been doing this for about 40 years," McCullough said. "I would've sounded a lot more confident 20 years ago."

The jet stream — a strong west-to-east flow of air typically located five to nine miles over the U.S.-Canada border — causes droughts when larger-than-normal north-south waves in its flow push precipitation away from a region for an extended period, said Jennifer Francis, a senior scientist at the Woodwell Climate Research Center.

"A growing body of research is finding that wavy jet-stream patterns are occurring more often, in part because the Arctic is warming three to four times faster than the globe as a whole, which reduces the north-south temperature difference that fuels the jet stream," Francis said. "A weaker jet stream is more easily deflected from its west-to-east path by things like mountain ranges and abnormal temperature patterns, which causes larger north-south excursions and increased waviness."

Increasing disturbances to the jet stream will cause more temperature and precipitation extremes in the northern hemisphere, Francis explained.

"When it comes to Québec's reliance on rainfall to fill rivers and reservoirs to generate electricity, this aspect of human-caused climate change is indeed a concern," Francis said. "Some years will bring extended droughts. Others will bring prolonged rains. Both extremes are expected to occur more often as we continue to add heat-trapping gases to the atmosphere."

As increased temperatures and decreased snow cover dry out soil, wildfire risks also are increasing in Québec, creating additional reliability risks on the power system, which can have knock-on

effects on reliability in the U.S. In 2023, a forest fire caused the shutdown of a transmission line in Québec during New England's evening peak, triggering an ISO-NE capacity deficiency. (See *Canadian Wildfires Trigger ISO-NE Capacity Deficiency*.)

According to an *analysis* by World Weather Attribution, an academic research group, "climate change made the cumulative severity of Québec's 2023 fire season to the end of July around 50% more intense, and seasons of this severity at least seven times more likely to occur."

'More Dynamic Changes in Flow'

In the coming decades, with the anticipated growth of intermittent renewables across the Northeast, Hydro-Québec expects its reservoirs to be used less as a baseload power resource and more as a massive balancing resource, allowing the company to conserve water during periods of high renewable production. (See *Québec, New England See Shifting Role for Canadian Hydropower*.)

The economic justification for a large-scale two-way exchange of power between regions likely will not occur until a significant number of offshore wind projects come online, which may not be until the mid-2030s or later. However, Vineyard Wind and Revolution Wind appear on track to eventually deliver about 1,500 MW of capacity to the New England grid, which could drive more frequent power exchanges between regions during periods of high production.

"With all that renewable energy that is being integrated in the electrical grid, we will see more dynamic changes in flows on the interties," Nadeau said, adding that it is harder to forecast changes to the overall balance of imports and exports.

This phenomenon could help the region address a major need for clean firm energy to help meet state climate targets in the coming decades. (See *ISO-NE Study Lays Out Challenges of Deep Decarbonization*.) A 2021 study found that increased transmission capacity between regions would significantly reduce the overall costs of decarbonization by 2050 and limit the need to overbuild intermittent renewables.

However, if Canadian hydropower ultimately is to help displace fossil units in New England, the region must be able to rely on the power when it is needed.

While imports from Québec have performed during capacity deficiencies in the region in recent years (aside from the 2023 wildfire-induced line outage), the decrease in overall import levels since 2023 has given fuel to arguments that imports from Québec are not as reliable as in-region generation.

In NEPOOL debates over the development of a new capacity accreditation framework for ISO-NE, representatives of generation companies have argued the RTO overestimates the benefits of its interregional transmission lines during emergency events, noting that these tie benefits are not backed up by capacity supply obligations. (See *ISO-NE Discusses Details of New Prompt Capacity Market*.)

Generation companies in New England also have expressed concern about the overall annual level of imports the region can expect to receive from Québec.

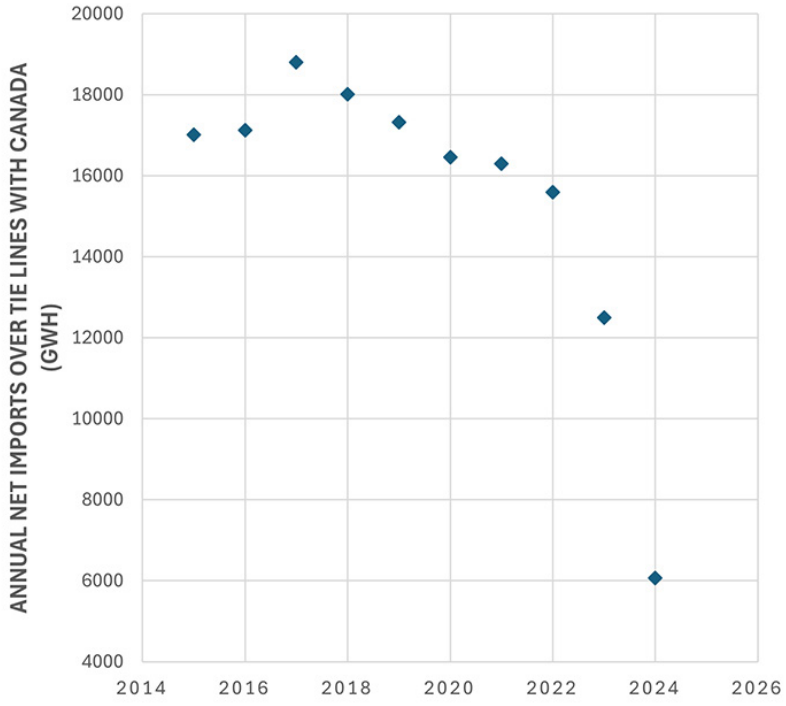
While the NECEC transmission project is intended to provide firm supply from Hydro-Québec, skepticism about how much incremental power the project will provide the region dates back to state regulatory proceedings for the power procurement. Multiple groups voiced concern in the proceedings that the contracts do little to guarantee net imports above the historical levels to New England.

In its approval of the contracts in 2018, the Massachusetts Department of Public Utilities wrote that the NECEC power purchase agreements would guarantee firm power deliveries incremental to what Hydro-Québec "would otherwise be expected to deliver to New England through its ongoing, largely non-firm commercial trading activities (*D.P.U. 18-64*)."

Ultimately, when NECEC comes online, flows from Québec to New England are poised to increase; the NECEC contract requires the company to send 9.55 TWh of power annually, compared to the 6.3 TWh of power imported to New England in 2024.

The export commitments, coupled with the addition of Vineyard Wind and Revolution Wind, may correspond with an increase in Québec's spot market imports from New England, potentially mitigating the change to the overall balance of power exchanges. Beyond its export commitments, the total amount of power Québec sends back to New England may depend in large part on how long the drought conditions persist.

"At the moment, given the forecasts of a significant deficit at Hydro-Québec, I don't think [NECEC] will change the balance at all," McCullough said. "There's nothing in the contract to prevent them from buying cheaply in New England, storing it and sending it back to New England." ■



New England annual net imports (GWh) | © RTO Insider LLC

Behind-the-meter Solar Shines in ISO-NE Capacity Deficiency Event

By Jon Lamson

Amid the rapid growth of behind-the-meter (BTM) solar in New England, a capacity deficiency event demonstrated the significant benefits of solar resources, along with their limits in displacing fossil resources during peak load periods.

On June 24, extreme heat and humidity caused ISO-NE peak demand to surpass 26,000 MW at about 7 p.m., marking the region's highest peak load since summer 2013. (See *Extreme Heat Triggers Capacity Deficiency in New England*.)

Without the contributions of BTM solar, ISO-NE estimates the peak would have reached over 28,400 MW at about 3:40 p.m. The 2,400-MW reduction in the region's peak provided significant cost and reliability benefits to the grid. According to an *analysis* by the Acadia Center, "BTM solar avoided as much as roughly $19.4 million in costs on this single day by suppressing the overall price of wholesale electricity."

In recent years, New England has seen annual additions of about 700 MW of BTM solar capacity, largely driven by state policy in Massachusetts and Connecticut. This has helped prevent load growth, pushed peaks later in the day and contributed to *a growing duck curve* and evening ramping requirements in the region. (See *Growth of BTM Solar Drives Record-low Demand in ISO-NE*.)

While BTM solar made a significant contribution to lowering the peak load, fossil resources continue to dominate the generation mix during the peak hour. ISO-NE estimates that carbon-emitting generation "provided about 74% of total energy consumed in the region during the peak" on June 24, including over 12,000 MW of natural gas generation, over 3,000 MW of oil generation and about 300 MW of coal generation.

The region's reliance on fossil generation to keep the grid running was not without challenges — outages of large fossil units appear to have played a major role in triggering the deficiency event. Natural gas generation declined by about 1,000 MW immediately prior to ISO-NE's declaration of a capacity deficiency, and the RTO *estimates* there were about 2,550 MW of generator outages and reductions at the time of the declaration.

The performance of BTM solar, coupled with fossil unit outages, has drawn attention from solar advocates. At a Massachusetts legislative *hearing* on June 25, several representatives of solar companies pointed to the benefits of solar during the deficiency when arguing against a proposal from Gov. Maura Healey (D) to reduce net metering compensation for new large solar facilities. (See *Mass. Gov. Healey Introduces Energy Affordability Bill*.)

"Solar … is the reason we didn't have backouts and we didn't have even higher prices and even higher emissions over the last few days," said Jessica Robertson of New Leaf Energy.

However, incremental standalone solar capacity likely will have diminishing effects on peak loads in the coming years, as BTM solar has pushed peak periods into the evening, when solar production declines rapidly. ISO-NE's 2025 Capacity, Energy, Loads and Transmission report estimates that increasing BTM solar will reduce the region's gross summer peak by only an additional 144 MW by 2034.

In the wake of the capacity deficiency event, clean energy advocates made the case that increased energy storage capacity would have provided significant benefits during the peak.

"Had we had even more behind-the-meter solar paired with storage online, we could have potentially completely avoided that absurd price spike later in the evening," said Kyle Murray of the Acadia Center at the June 25 hearing.

Shutterstock

The Acadia Center wrote in its analysis of the event that there is "clear evidence that additional BTM battery energy storage would have been able to further reduce the overall cost to consumers by increasing flexibility and shifting the solar production later in the day, dampening the early evening peak prices."

Consulting firm Power Advisory *estimated* that 1,000 MW of battery storage capacity could have reduced real-time LMPs by an average of over $100/MWh during the event, saving up to $17/kW. The firm also estimated that offshore wind would have reduced LMPs by $47/MWh, assuming a capacity factor of nearly 50% based on prevailing wind speeds.

While battery storage is in its infancy in the region, it is poised to grow quickly in the coming years, which would help to balance the production profile of storage. About 1,800 MW of energy storage cleared in ISO-NE's capacity auction for the 2027/28 capacity commitment period, including 700 MW of new storage. Storage resources also account for 45% of the active projects in ISO-NE's interconnection queue, totaling 18.4 GW in capacity. ■

Why This Matters

Behind-the-meter solar has helped to significantly lower the peak load in ISO-NE but will likely struggle to provide additional peak reductions unless paired with energy storage.

FERC Denies MISO, SPP Waiver of Joint Study Process

By Tom Kleckner

FERC has denied a waiver request by MISO and SPP to make changes to the Coordinated System Plan (CSP) under their joint operating agreement, saying it is not the "appropriate vehicle" to improve the process.

The July 2 finding was made without prejudice, allowing the RTOs to submit proposed revisions to their CSP in a future Section 205 filing under the Federal Power Act (*ER25-943*).

The grid operators filed the request in January, asking the commission to allow them to incorporate multiple scenarios in a single 10-year model instead of the multiyear analysis required by their JOA. They also asked to use multiple benefit metrics to evaluate reliability and public policy interregional transmission projects rather than the agreement's narrowly defined "cost avoidance of pre-existing regional projects." (See *MISO, SPP Ask FERC for JOA Waiver to Conduct More Meticulous Interregional Study*.)

MISO and SPP contended that previous CSP studies were unsuccessful in "developing solutions where both RTOs benefit" and "have not yielded any interregional projects" for more than a decade.

FERC said the request did not meet the commission's criteria for granting tariff waivers that: the applicant acted in good faith; the waiver is of limited scope; the waiver addresses a concrete problem; and the waiver does not harm third parties or have other undesirable consequences.

The commission found the request was not limited in scope because waiving a multiyear analysis "would appear to relieve them of a discrete tariff obligation." It said waiving the RTOs' tariff obligation to evaluate the benefits of reliability and public policy interregional projects as the avoided cost of regional projects that address the same reliability or public policy issue is "a significant change to the CSP study scope."

FERC said the waiver request does not address a concrete problem because the grid operators did not show that expanding the study scope would address the problem they identified. "That is, the proposed expanded CSP study might not identify transmission solutions that meet [the RTOs'] selection criteria," FERC said.

FERC has denied a MISO-SPP waiver request of their joint study process. | *ITC Holdings*

The commission said it was unpersuaded by the grid operators' claim that their waiver request is consistent with FERC precedent granting "waivers modifying transmission planning study requirements and timelines and addressing inefficient market outcomes." The commissioners said those proceedings involved waiver requests of tariff deadlines to allow the applicant additional time to comply with a tariff requirement, not to change the requirement outright.

Commissioner David Rosner dissented from the 2-1 vote. Commissioner Judy Chang did not participate.

Rosner said he believed MISO and SPP satisfied the commission's waiver criteria. Noting the CSP study has not yielded a project in more than 10 years, he said the proposal to waive two JOA provisions related to technical planning assumptions will "better tailor the study to their regional needs, making it more likely to yield useful results."

"The commission should not stand in the way of simple solutions that give MISO, SPP and their stakeholders flexibility to improve the accuracy of their study," Rosner wrote. "The alternative compels MISO and SPP to commit resources towards an inefficient study and prevents the regions from identifying needed interregional transmission projects."

"As the dissent rightfully points out, the CSP studies have not yielded any interregional transmission solutions for more than a decade," Chair Mark Christie and Commissioner Lindsay See said. "In other words, the current situation is not a surprise to either MISO or SPP, and the circumstances that led to this situation are not outside of their control. While we appreciate MISO's and SPP's desire to improve their CSP process, a waiver request is not the appropriate vehicle to achieve such an outcome."

The American Council on Renewable Energy (ACORE) and International Transmission Co. filed comments supporting the MISO-SPP application. They said the waiver request would have yielded an expanded CSP study that would identify interregional projects that benefit both the MISO and SPP regions and would support a more reliable and efficient transmission system. ■

Court Says Mich. TO Cannot be Sole Owner of Upgrades on Shared Line

By Amanda Durish Cook

A yearslong dispute over who gets to own a 345-kV network upgrade in Michigan had the D.C. Circuit Court of Appeals meditating on the definitions of "system" versus "facility."

Ultimately, the D.C. Circuit decided that Michigan Electric Transmission Co. (METC) does not have exclusive ownership rights to an almost $12.4 million upgrade to support EDP Renewables' in-progress 120-MW Eagle Creek Solar Park (*24-1039*).

The court's July 1 order means that Michigan Public Power Agency (MPPA) and Wolverine Power Supply Cooperative, as fellow co-owners of the existing Styx-Murphy 345-kV line, also should have a stake in the line's extension and new substation *construction*.

The D.C. Circuit examined the semantics of MISO's Transmission Owners Agreement to reach its conclusion. METC argued it should be the sole owner of the upgrades because they will be located within its larger transmission system. It also said that 33-year-old agreements bestowing partial line ownership to MPPA and Wolverine don't extend to network upgrades on the line.

Wolverine owns 64% of the Styx-Murphy line, while MPPA owns 35% and METC owns 1%. MPPA and Wolverine acquired their ownership in 1992 through an antitrust settlement agreement to limit Consumer Energy's market power in the Lower Peninsula. METC, meanwhile, purchased its stake from Consumers in 2020.

METC argued that the circumstances behind MPPA and Wolverine's ownership made them ineligible for network upgrade ownership interest. It argued the two have "limited grants of ownership" on the line that permit them to transmit certain megawatt flows over METC's larger system and nothing more.

METC also said per the MISO Transmission Owners Agreement, the line qualifies only as a "facility" and not a "system." METC said the distinction between the phrases means it, as the owner of the larger system, is entitled to the network upgrade, not MPPA and Wolverine, which merely own a facility on its system.

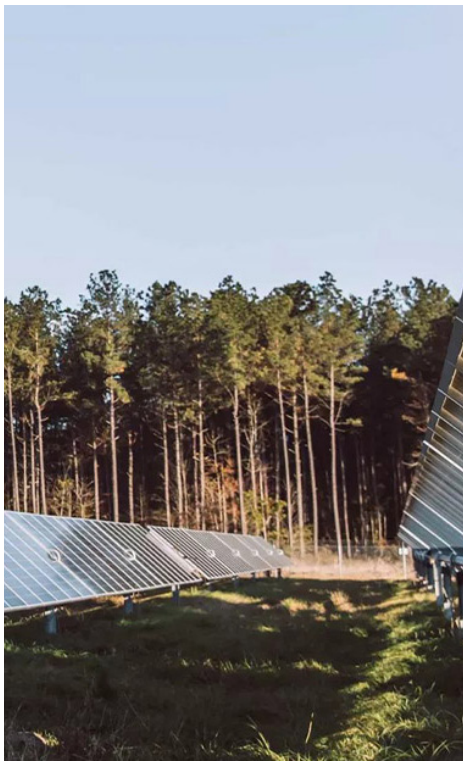
FERC previously determined that no agreement related to the Styx-Murphy line "conclusively" established exclusive ownership. The three utilities have been disputing ownership rights of the upgrade since 2023. (See *FERC Rejects MISO Solar Farm Interconnection Agreement, TO Challenges Upgrades Ownership*.)

The D.C. Circuit agreed that the context of Wolverine and MPPA's rights to the line didn't make them less worthy of owning generator interconnection-related network upgrades. The court also said a dictionary reading of "system" versus "facility" does not "demarcate as sharp a distinction … as METC would like." It said previous FERC orders METC cited as proof "merely refer to METC's 'transmission system' and the Styx-Murphy line as a 'facility' without reference" to specific sections of the MISO Transmission Owners Agreement.

The court said METC's rigid interpretation would mean that MISO Transmission Owners who own a single facility would be barred from ever constructing or owning a network upgrade for a generation interconnection, which is not the case.

"It would make no sense for the other TO signatories or for MISO itself to discriminate in this manner against the owner of only one facility," the court reasoned.

The D.C. Circuit said it agreed with the commission that METC couldn't claim ownership of an upgrade to a line it doesn't completely own "simply because that existing facility was located within its 'system.'"



EDP Renewables

"That result 'would ignore the ownership, and responsibilities, of the actual owner(s) of the existing transmission facilit(ies),'" the court said, quoting FERC. It also said it would render a portion of MISO's Transmission Owners Agreement "meaningless."

The court seconded FERC's conclusion that the history behind MPPA and Wolverine's ownership provisions wouldn't exclude them from owning network upgrades on the line. It said the antitrust agreements conferred "unrestricted pro rata ownership in the Styx-Murphy line" which enables them "to compete on an equal footing with other TOs."

"Limiting the agreements as METC requests … could only help entrench rather than restrain METC, an effect at odds with the pro-competitive purpose of the agreements," the court said. It added that it could not tack on a "new prohibition" to the decades-old agreements.

METC, meanwhile, has been building the network upgrades to support Eagle Creek. ■

The Bottom Line

The D.C. Circuit Court of Appeals decided that a Michigan TO can't claim exclusive ownership rights to network upgrades for a solar farm on a 345-kV line it jointly owns with other utilities.

Moody's to NYISO: U.S. Edging Near Recession

By Vincent Gabrielle

NEW YORK CITY — Stakeholders discussed uncomfortable economic possibilities at NYISO's 2025 Spring Economic Conference. The Trump administration's unpredictable policies on import tariffs, diplomacy and immigration are creating difficulties for businesses.

"We are calling that the economy will slow very significantly, running on the precipice of recession," said Adam Kamins, senior director at Moody's Analytics.

This was the first time in six years that NYISO and its stakeholders convened the annual Spring Economic Conference at Consolidated Edison. The mood leading into the presentation was congenial and relieved. The intense heat wave that gripped New York like a fever had broken the night before.

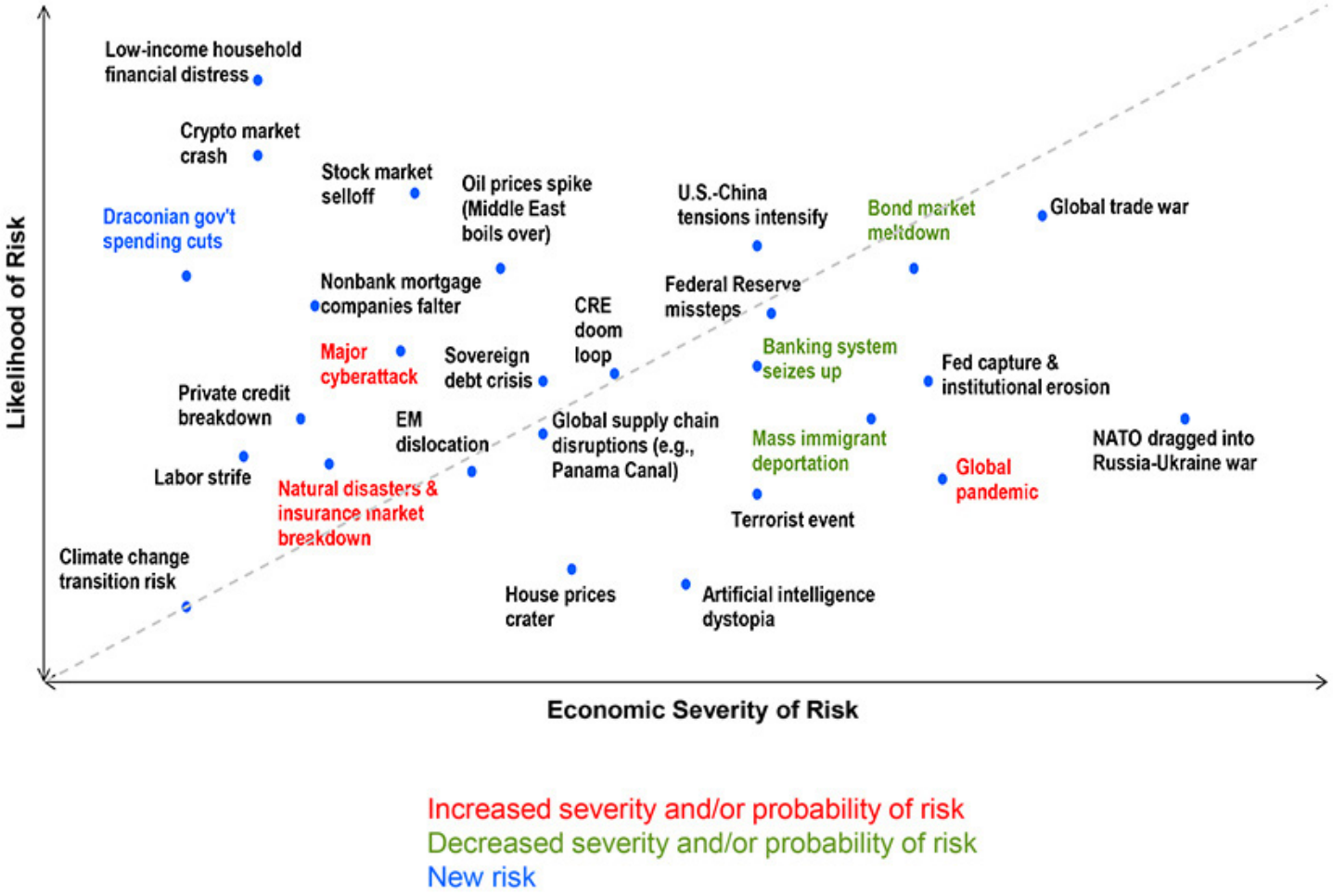
Kamins said the Trump administration's "tariff roller coaster" had created an unstable situation for global trade. He displayed a timeline of the tariffs, showing the erratic spikes, plateaus, dips and valleys that have affected imports since February.

"It's whiplash for importers and exporters," Kamins said. "If you narrow it to the 'Liberation Day' tariffs in April, you have these very aggressive 10% baseline tariffs, plus these aggressive reciprocal tariffs … . It's honestly pretty haphazard."

Why This Matters

NYISO's load growth forecasts and reliability needs are partly predicated on economic indicators for New York and the United States. A slow economy likely means slower load growth.

Kamins said the administration's attempt at reciprocal tariffs didn't make sense. Typically, a government would set these based on another nation's goods equal to the rate taxed abroad. Instead, Trump's



Moody's Analytics

import duty rates were based on trade deficits. This led to poor nations that cannot afford U.S. goods, like Lesotho, receiving high tariffs on raw materials exports.

"We aren't exporting anything there," Kamins said. "They aren't placing a tariff on us because it wouldn't matter. Nothing is going there anyway."

A stakeholder said that even if you supported tariffs, the way they were implemented created a "chilling effect" on investment decisions. Kamins replied that the stakeholder had intuited one of his next slides.

"If firms are thinking about investing or hiring, they need to know the rules of the game," Kamins said. He said the roller coaster effect limited any potential upside of tariffs by making it difficult to onshore manufacturing, something the Trump administration has said it wanted to do.

Kamins then showed several economic indicators that captured some of what he saw as the fallout of the Trump administration. Container ships were arriving at port empty at Long Beach, Calif., the largest shipping harbor in the U.S. Hiring and job switching have slowed. GDP growth has slowed. Investment plans for the next year have declined sharply. While the overall economy isn't showing signs of crashing yet, things aren't headed in the right direction.

While overall workforce growth was flat, Kamins said, the decline of immigrant participation has disproportionately impacted specific industries, like construction, generating headwinds against growth. New York is more dependent on immigrants than other states for labor and population growth, Kamins explained.

New York's Outlook

Kamins projected that New York *generally* would follow national trends with some specific exceptions. Compared to nearby states and peer large states, New York's economy was doing well. Its metro areas were growing in terms of payroll, primarily buoyed by growth in New York City and the health care sector.

"New York is the best-performing state in the region as of last fall and was No. 5 nationally at the time," Kamins said. "The only other semi-large state that was outperforming New York was South Carolina."

Metro-area indicators showed most of the growth in the state was concentrated in New York City, with some pockets of growth in Albany and Syracuse.

"When we talk about Syracuse, the most important factor in the outlook is the semiconductor industry and the Micron chip fab [fabricator]," Kamins said. "Construction firms are ramping up hiring in anticipation of that."

Albany's strong growth was due to the state government and the performance of local universities.

New York City will be unusually affected by Trump administration policies, Kamins predicted. He referenced sharp declines in Canadian cross-border traffic. European tourism also is down. While tourism has recovered since the pandemic, these factors could cause headaches in the near future.

"New York City relies heavily on international tourism, far more than the rest of the country," he said.

A stakeholder based in the North Country concurred, noting that Canadians no longer were coming to shop. Kamins noted that immigration restrictions, closed borders and Immigration and Customs Enforcement activity made the U.S. a far less attractive option for tourism or international studies.

New York statewide also suffered from a profound lack of housing inventory, Kamins said, which creates inflationary pressure.

"Price growth for single-family homes is well above the national average," Kamins said. "This is primarily owed to the supply side of the market. Supply shortages are present pretty much everywhere in the state, but they are most acute in Rochester."

He said the amount of supply for housing could be measured in "weeks" in certain parts of the state. Homes just don't stay on the market. While New York City isn't affected by single-family home prices generally, there also was a supply shortage creating rent inflation.

The presentation closed on an optimistic note: The state still is seeing billions of dollars in investment in semiconductor manufacturing upstate. Micron and Wolfspeed remain committed to developing microchip fabricators, despite delays and financial difficulties. ■

NYISO Proposes ICAP Changes for New Entry Ahead of CHPE

By Vincent Gabrielle

NYISO on July 2 released its proposed *changes* to certain capacity market parameters to accommodate the Champlain Hudson Power Express transmission project, as well as facilitate the new entry of resources.

The changes, presented to the Installed Capacity Working Group, would see NYISO developing two sets of market parameters for capability years where "triggering resources" did not enter the market by May, the first month of the ISO's capability year.

This would mean that NYISO would use an alternative set of market parameters as the foundation of the market until the resource begins participating. The ISO would run two installed reserve margin (IRM) studies: one assuming the new resource (in this case CHPE) is in service, and one assuming it is not. This would create two sets of transmission security limit (TSL) floors, locational capacity requirements, capacity accreditation factors, system translation factors, unforced capacity demand curve parameters and load-serving entity minimum capacity requirements.

CHPE is a 1,250-MW HVDC line that will run between Quebec and New York City and is expected to go into service in 2026 — but the exact date is unknown. NYISO is keeping an eye on its progress, but it is worried it will be *mistimed* with the beginning of the capability year. Most of the ICAP market is predicated on annual inputs, with limited seasonality. CHPE's entry would have major implications for the reliability parameters in the New York City zone.

Beaumont Generating Station on the Saint-Maurice River in Mauricie, Quebec | *Hydro-Québec*

While NYISO does not anticipate CHPE to shift the IRM, it does anticipate the TSL floor to increase by about 4%, which would impact "downstream" parameters.

NYISO is also proposing that notice requirements for new capacity resources be changed so they must achieve commercial operation prior to notifying the ISO that they intend to participate in the market. The ISO must receive the notification by the first business day of the month before the month the resource wants to qualify for participation. This would only apply to resources whose entry would change contingencies evaluating the transfer capability into a zone.

Stakeholders questioned the rigidity of the timing NYISO laid out, saying that it could possibly create a situation where the market parameters were acting under the assumption that a new resource was not participating when it was.

"If commercial operations start during the middle of June, that means that the resource wouldn't be able to provide capacity until September," one stakeholder said. "I'm having trouble understanding why you think this is an improvement."

There was also some back and forth with Zach Smith, senior manager of capacity and resource integration for NYISO, about why changing the ICAP market parameters could not be moved more swiftly. Smith said he would look into whether it was possible to increase the flexibility of the proposal.

Another stakeholder asked NYISO to make the forecasted commercial operation dates of resources like CHPE available to the market so they could plan for the shift in market parameters. ■

NYISO Management Committee Briefs

The NYISO Management Committee passed two motions at its brief June 30 meeting, unanimously recommending that the Board of Directors approve them.

The committee recommended *revisions* to the ISO's Joint Operating Agreement with PJM for the upcoming activation of a phase angle regulator at a new 345-kV Dover substation for approval. The project is part of the *AC Transmission Segment B public policy transmission project*, which is intended to reduce congestion between the Capital District and downstate. (See *NYISO Board Selects 2 AC Public Policy Tx Projects*.)

The committee also passed *revisions* to the NYISO tariff to implement transmission owners' right of first refusal over upgrades in the reliability and economic planning processes. (See "Committees Approve Updates to ROFR Implementation," *NYISO BIC & OC Briefs: Week of June 16, 2025*.) ■

— Vincent Gabrielle

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SPP Stakeholders Reject Urgent Dispatch Change

By Tom Kleckner

SPP stakeholders have rejected a proposed tariff revision (*RR687*) that would help the grid operator connect generation more quickly.

Staff said the change would improve the definitive integration system impact study (DISIS) process by modifying the RTO's dispatch method to ensure the added generation's reliability and also lower exports to a realistic level. The proposal failed with only 36% of the vote during the Markets and Operations Policy Committee's June 30 virtual special meeting.

Natasha Henderson, SPP's senior director of grid asset use, said during a June 26 education session that the large amount of generation in the queue, combined with the dispatch method, is causing unrealistic generation exports. That assigns noncommercial viable upgrades to generators.

The 2023 DISIS includes 28 GW of capacity from 127 projects, about half of which are wind and solar resources. Like all SPP study clusters, staff analyze them in five groups: North, Nebraska, Central, Southeast and Southwest.

Henderson said SPP is seeing dropout rates between 67 and 100% in the study clusters that are causing further downstream issues.

"What happened in the 2022 DISIS is after all of this generation dropped out, $22 billion of associated upgrades also went away," she said. "So, when we finish the 2023 DISIS Phase 2, it's likely those generators are now going to see that same $22 billion of upgrades assigned to them. The proposed dispatch changes will mitigate that. It will not completely eliminate it, but it will help a little bit."

Oklahoma Gas & Electric's Adam Snapp, a member of the Transmission Working Group (TWG), cautioned against the proposal, saying no one knows the full effect the modified dispatch will have on the 2023 DISIS. The TWG twice rejected RR687 in June, 0-13 with five abstentions, and 6-14 with three abstentions.

"There are still a large number of resources that are in the 2023 queue that are benefiting from billions of dollars of upgrades that are currently assigned to the 2022 cluster," Snapp said. "Once those 2022 cluster resources withdraw, those costs will ship to the 2023 resources that will trigger a lot of resource withdrawals from the 2023 cluster. What we're effectively doing here is asking the policy to overrule TWG on a very technical matter without understanding the whole impact of … that decision."

SPP had hoped to receive an expedited approval from MOPC so it could apply RR687 to the DISIS 2023 Phase 2 clusters that hadn't been completed before July 1. That study will conclude before the committee's regularly scheduled July 15-16 meeting.

"We do think that this needs to be ported over in future generation interconnection processes," said SPP's Casey Cathey, vice president of engineering.

The issue will be sent back to the TWG for further consideration and discussion. The group next meets July 29 in Kansas City. ■

SPP expects to see little generation move to next DISIS stage across all five groups. | *SPP*

Missouri AG Opens Inquiry into Grain Belt Express

By Tom Kleckner

Missouri Attorney General Andrew Bailey says he has opened an investigation into Invenergy's Grain Belt Express transmission project, an 800-mile, HVDC line spanning four states that has been under development since 2010.

Bailey told Invenergy in a June 27 *filing* that he "has reason to believe" Grain Belt's developers have "used deception, fraud, false promise, misrepresentation, unfair practice or the concealment, suppression or omission of material fact in connection with its statements and actions" related to the project.

He sent a *letter* to the Public Service Commission on July 1 urging it to re-evaluate the project's certificate of convenience and necessity by using its authority to "demand" updated long-term planning and revoke project approvals that are no longer in the public interest.

A PSC spokesperson told *RTO Insider* that the commission is reviewing the attorney general's request and declined further comment.

Bailey said the Grain Belt application "relied on speculative and possibly fraudulent assumptions." He said the developers' calculations relied "significantly" on a carbon tax, pointing out that neither Missouri nor the U.S. government have carbon-reduction policies.

"Grain Belt's speculative and faulty calculations based on anticipated carbon tax has more than likely inflated demand for this project and dramatically overstated any resulting benefit to Missourians, directly undermining any claims of demonstrated need, economic feasibility and public interest," Bailey said in the letter to the PSC.

"We've been absolutely transparent with everybody involved," Michael Polsky, Invenergy's founder and CEO, told *The New York Times*. "Whatever investigation they want, we will fully cooperate. We have nothing to hide. We've done everything above board."

A Grain Belt spokesperson called the investigation a "last-ditch and obviously politically driven attempt to delay construction" of the project when "our country is facing a national energy emergency," as declared by President Donald Trump. (See *What is and isn't in Trump's National Energy Emergency Order*.)

Why This Matters

The Grain Belt Express has been in development for about 15 years and faced numerous challenges getting approvals from the states it would cross, which include Kansas, Illinois and Indiana.

"We should be building energy infrastructure in America, but the Missouri attorney general is instead playing politics with U.S. power," the spokesperson said in an email. "Electricity demand is rising across the country, and we urgently need transmission infrastructure to deliver power. Projects like Grain Belt Express are the answer to providing all forms of affordable and reliable electricity to U.S. consumers."

U.S. Sen. Josh Hawley (R-Mo.) has also weighed in with a *letter* to the Department of Energy in June asking Secretary Chris Wright to terminate a *$4.9 billion loan guarantee* issued by the Loan Programs Office in 2024.

Hawley, who has called Grain Belt Express a "boondoggle," noted the department is moving forward with the draft environmental impact statement, "a key step in approving the loan."

Invenergy says the $11 billion project will save $52 billion in energy costs over 15 years, create 5,500 American jobs and power up to 50 data centers. A 2022 *economic analysis* conducted for Invenergy found that the project would result in $20 billion in total investment and create more than 20,000 temporary jobs and more than 400 permanent jobs in Illinois, Kansas and Missouri.

Invenergy says Grain Belt, a merchant open-access line, will move about 5,000 MW of a "diverse mix of energy" from Kansas across Missouri and Illinois to Indiana. The project will deliver cost savings and strengthen reliability for 29 states and D.C. and more than 40% of Americans, it said.

The project would create links between the SPP, MISO, Associated Electric Cooperative Inc. and PJM grids.

Kansas, Missouri, Illinois and Indiana have all approved the project. The Missouri PSC found the project would save the state's customers as much as $18 billion, Invenergy said, and noted municipal utilities in 39 communities have contracts with it for power delivery and contractually guaranteed cost savings.

The project has faced pushback from Missouri landowners, who are opposed to a for-profit private entity using eminent domain. Bailey has criticized Grain Belt for filing nearly 50 eminent domain lawsuits against Missouri landowners.

In a *blog post*, Invenergy said "responsible transmission developers respect private property rights and make every effort to negotiate with landowners." It said it has "among the strongest set of landowner protections and compensation packages, including a code of conduct and agricultural impact mitigation protocol."

Invenergy says it has completed over 95% of land acquisition for Phase 1, the segment connecting Missouri and Kansas. The phase's construction is scheduled to start in 2026.

Grain Belt's developers received some good news on July 1 when the D.C. Circuit Court of Appeals denied a rehearing request from a group of Illinois landowners. The court dismissed the lawsuit in April, finding the group had failed to demonstrate that they will suffer a "certainly impending" injury-in-fact (24-1213).

The landowners were appealing FERC's order in February 2024 and a subsequent rejected rehearing request over the commission's authorization of Grain Belt's ability to charge negotiated rates for the HVDC project (ER24-59). (See *Grain Belt Express Gets Partial Approval for Negotiated Rate Authority from FERC*.)

Grain Belt has been under development since 2010, when the now-defunct Clean Line Energy first proposed the transmission line. After years of regulatory, legal and political hurdles, Clean Line sold the project to Invenergy. (See *Invenergy Renewing Push for Grain Belt Express*.) ■

Google Data Center Electricity Consumption up 27% in 2024

Tech Giant Reports Strong Focus on Increasing Efficiency, Reducing Emissions

By John Cropley

Google is reporting another sharp annual jump in electricity consumption at its data centers but says greenhouse gas emissions were lower in 2024 than 2023 by some measures.

The company in its *2025 Environmental Report* said it bought 32.11 million MWh worldwide in 2024 — 0.83% as much as the *total electricity consumption in the 50 states* in 2023 and 499% more than Vermont, the state that used the least electricity.

Electricity use by data centers, particularly with the advent of energy-intensive artificial intelligence, is the focus of much debate and consternation among grid operators and policymakers. Some maintain the dire predictions are overblown, others say the demand is real, and there is a looming crisis on which the nation's future rides.

Google is a giant — its soaring power consumption may or may not be a bellwether of the tech sector as a whole. But its purchased electricity use in 2024 was 27% higher than in 2023 and 112% higher than in 2020.

For perspective, *fellow tech giant Microsoft reported* 29.83 million MWh consumed in its fiscal 2024 — 26% more than in fiscal 2023 and 177% more than in fiscal 2020.

Both companies reported small additional amounts of energy purchased in the form of fuel, heat, steam and chilled water, or generated by on-site renewables.

A potentially huge environmental footprint accompanies all those gigawatt hours and all those data computations.

In the annual report issued June 27,

Why This Matters

The report quantifies the soaring energy demand created by Google's data centers and the company's efforts to meet those needs sustainably.

Google frames its power consumption within efforts to reduce that footprint and increase sustainability.

"In 2024, we made our largest-ever procurement of clean energy, adding 8 GW to our portfolio, more than we've ever done in a single year," Google Chief Sustainability Officer Kate Brandt *said in announcing the Environmental Report*.

Google's Midlothian, Texas, data center is shown. | *Google*

Google nearly doubled its on-site renewable electricity from 10,700 MWh in 2023 to 20,500 MWh in 2024, for example. More than two dozen clean power projects contracted over the previous five years came online in 2024, raising Google's carbon-free energy use from 64% in 2023 to 66% in 2024, even as total energy use soared.

More broadly, Google said, energy-intensive AI data crunching is saving electricity beyond the data centers, through company products such as fuel-efficient routing, solar API, traffic signal management and machine learning-enabled thermostats.

Google says those five products alone enabled an estimated 2024 emissions reduction of 26 million metric tons. The company's goal is to reduce clients' carbon-equivalent emissions by 1 gigaton per year by 2030.

Google also has made headlines with its partnerships in advanced nuclear and geothermal development.

An entire school of climate activism is dedicated to calling out corporate greenwashing, and five days after Google issued its 120-page report, Kairos Fellowship *issued a 53-page report* criticizing its emissions reporting as misleading and its conclusions as wrongly self-congratulatory.

In the tenth annual report, Google acknowledges the gray areas within some decarbonization metrics.

It set out in 2012 to match its global energy use with renewable energy purchases; it reached 100% in 2017 and every year since, but a 100% match is not what it considers carbon-free.

"Even if a company buys clean energy in bulk and applies it to match its total usage over the course of the year, its real-time energy mix likely includes electricity generated from fossil fuels," the authors write.

Google continues to pursue its 24/7 carbon-free energy goal — a real-time match of electricity used with clean energy generated locally on the same grid in the same hour. On that measure, it claimed 66% success in 2024.

In the final tally, Google reported its Scope 1 emissions and certain Scope 2 emissions were lower in 2024 than 2023, while Scope 3 emissions were higher. Combined, they are 6.3% higher, but Google does not include in that equation another type of Scope 2 emissions that showed the biggest year-over-year increase of all.

Carbon intensity per unit of revenue, per full-time employee equivalent and per megawatt hour of energy consumed all were significantly reduced year over year.

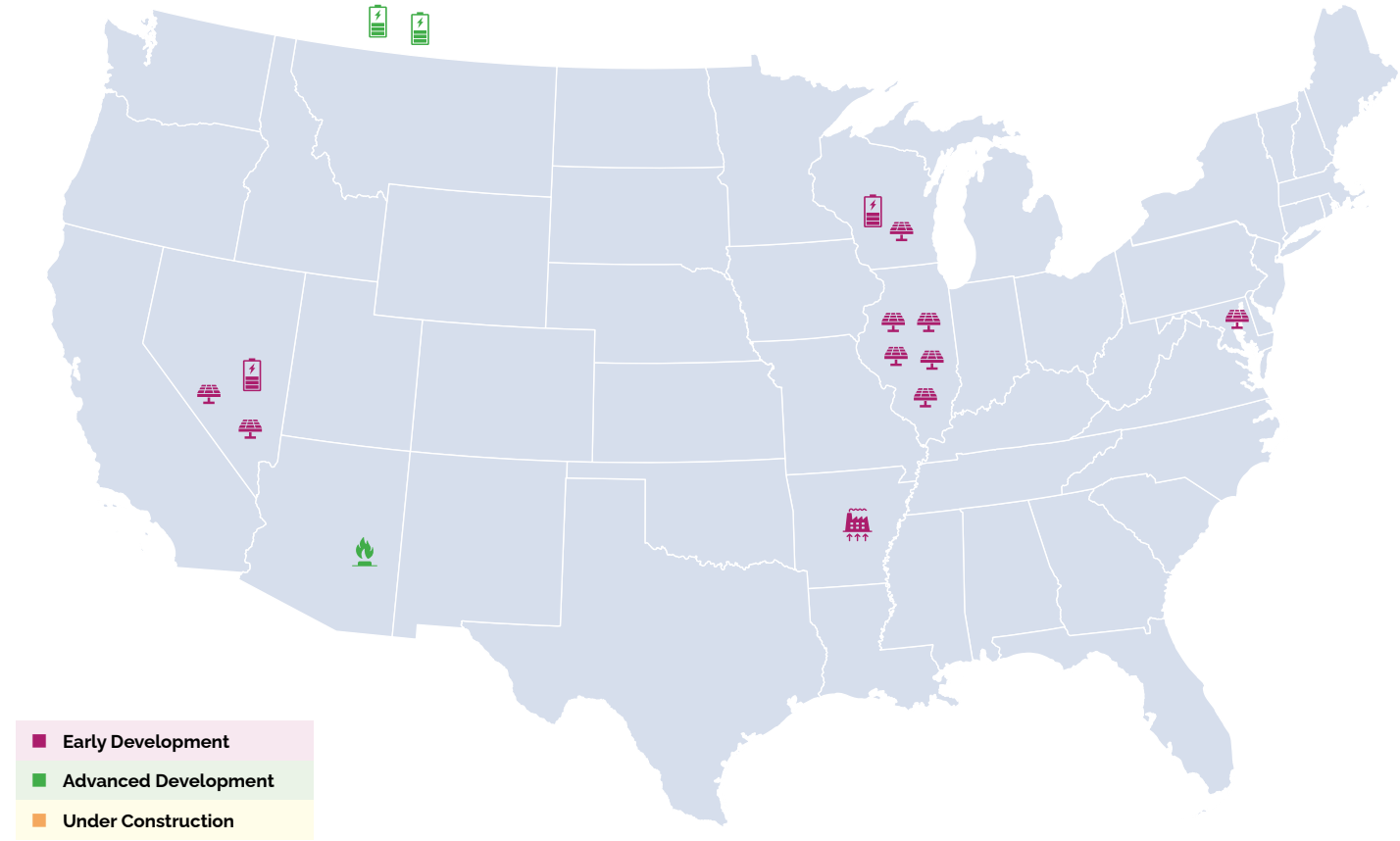
The hurdles Google sees to further progress are the same ones that face everyone else: interconnection delays, regulatory bottlenecks, logistical and economic constraints, limited local supply, permitting challenges and regional variations.

The company reached only 12% carbon-free energy in the Asia-Pacific region in 2024, for example, compared with 70% in the United States, 5% in the Middle East/Africa and 92% in Latin America.

Google is pursuing multiple strategies for further progress but acknowledges the scale of the task, saying, "The path ahead is anything but simple." ■

Generation Projects Added in the Past Week

YES ENERGY



Solar Wind Energy Stoarage Natural Gas Geothermal Biogas

Data from Yes Energy

Project or Unit Name	Holding Company or Parent Organization	Primary Energy Source	State or Province	Capacity (MW)	In Service Year
Fox Solar	NextEra Energy, Inc.	Solar	WI	100	2028
Fox Solar BESS	NextEra Energy, Inc.	Energy Storage	WI	50	2028
Fairmount Solar 1	Ownership Undisclosed	Solar	IL	5	2027
Fairmount Solar 2	Ownership Undisclosed	Solar	IL	5	2027
Fox Solar 1	Ownership Undisclosed	Solar	IL	5	2028
Fox Solar 2	Ownership Undisclosed	Solar	IL	4	2039
Havana Solar	Ownership Undisclosed	Solar	IL	5	2031
Henkle Branch Solar 1	Ownership Undisclosed	Solar	IL	5	2027
Hiawatha Rd Solar 1	Ownership Undisclosed	Solar	IL	5	2028
Hiawatha Rd Solar 2	Ownership Undisclosed	Solar	IL	5	2029
Hiawatha Rd Solar 3	Ownership Undisclosed	Solar	IL	5	2029
Hiawatha Rd Solar 4	Ownership Undisclosed	Solar	IL	5	2030
Hiawatha Rd Solar 5	Ownership Undisclosed	Solar	IL	5	2030
Weiser Valley Solar	NextEra Energy, Inc.	Solar	NV		2100
White Pine Solar (NV)	AMPYR Global Energy	Solar	NV	350	2029
White Pine Solar BESS	AMPYR Global Energy	Energy Storage	NV	350	2029
Coronado Generating Station Natural Gas Conversion	Salt River Project	Natural Gas	AZ	822	2029
Clinton National Airport Geothermal Project (unofficial name)	Clinton National Airport	Geothermal	AR		2027
Wicomico Rayne Solar	Ownership Undisclosed	Solar	MD	5	2027
Buffalo Trail Wind North BESS	Engie	Energy Storage	Alberta	200	2028
Buffalo Trail Wind South BESS	Engie	Energy Storage	Alberta	432	2028

Company Briefs

NRC Approves Dominion's Request to Extend V.C. Summer

The Nuclear Regulatory Commission last week approved Dominion Energy's application to extend the operating license of its V.C. Summer power station in South Carolina until 2062.

The V.C Summer nuclear power station was originally licensed to operate for 40 years from 1982 through 2022. In 2004, the NRC approved a license renewal to allow operation for 20 more years through 2042. Last year, Dominion received a similar approval to extend the operating licenses for North Anna nuclear power station in Virginia for an additional 20 years.

More: *Reuters*

Delta Utilities Closes Purchase of Entergy's Natural Gas Business

Delta Utilities last week announced it had closed on its $484 million purchase of Entergy's natural gas business.

Earlier this year, Delta Utilities also completed the purchase of CenterPoint Energy's natural gas distribution operations in Louisiana and Mississippi.

More: *The Advocate*

Google Partners with Commonwealth for Fusion Plans

Google last week announced a partnership with Commonwealth Fusion Systems, a private company spun off from the Massachusetts Institute of Technology, which marks the company's first commercial commitment to fusion.

Google unveiled plans to buy 200 MW of fusion power from what CFS describes as the world's first grid-scale fusion power plant, known as ARC, based in Chesterfield County, Va.

ARC is expected to come online and generate 400 MW of zero-carbon power in the early 2030s. No financials of the deal were released.

More: *CNBC*

Terra CO2 Cements $124M to Slash Concrete's Carbon Footprint

Terra CO2, a Colorado-based startup focused on decarbonizing cement, last week said it recently closed on $124.5 million in Series B funding to build a new facility.

The company said it will be using the new funding to build a facility near Dallas capable of pumping out 240,000 tons of its supplementary cementitious material (SCM) annually. SCM is a broad class of materials that serve to replace Portland cement without sacrificing any qualities.

More: *TechCrunch*

Federal Briefs

EPA Puts Employees Who Signed Letter Criticizing Policies on Leave

EPA last week placed 139 employees on leave after they signed a letter criticizing the Trump administration's environmental policies.

The letter, titled a "Declaration of Dissent," accused the administration of undermining EPA's mission of protecting the environment by promoting "harmful deregulation" and showing "disregard for scientific expertise." The document, which was released publicly and received 620 signatures, outlined several areas of concern.

Employees were notified they had been placed in a "temporary, non-duty, paid status" for the next two weeks, pending an investigation, according to a copy of the email. EPA said it was not a disciplinary action.

More: *CBS News*

Trump's Bill Blows U.S. Emissions Goal by 7B Tons

President Donald Trump's dismantling of climate policy means the U.S. will add an extra 7 billion tons of emissions to the atmosphere from now until 2030, according to analysis of modelling from the Princeton University REPEAT Project.

The analysis shows that U.S. emissions are now set to drop to just 3% below current levels by 2030 rather than falling 40% as required to hit the now-defunct Paris Agreement target. This would leave the U.S. around 2 billion tons short of its greenhouse emissions target for that year, adding emissions equivalent to around 4% of the current global total each year.

Carbon Brief compared the impact of Trump's policies to a pathway on which the U.S. meets its former target, under the Paris Agreement, to cut greenhouse emissions by 50 to 52% from 2005 levels by 2030. The cumulative gap between this pathway and the administration's trajectory amounts to 7 billion tons of emissions over the next five years.

More: *Carbon Brief*

BLM Approves Drilling for Fast-tracked Lithium Project

The Bureau of Land Management announced it has approved a Nevada lithium exploration project for expanded drilling and development.

BLM issued a FONSI document — short for a Finding of No Significant Impact — for the project after saying it found no significant environmental impacts from 3 Proton Lithium's Railroad Valley project in Nye County. BLM also approved the company's exploration plans on 40 acres of public land across a 24,727-acre area.

The project was one of 10 mineral-related projects the Trump administration added to its FAST-41 program in May.

More: *Reno Gazette Journal*

State Briefs

REGIONAL

Judge Denies Motion to Fully Dismiss Lawsuit Against US Wind

A District Court judge last week allowed a lawsuit over US Wind's proposed offshore wind project to continue, though will now consider fewer arguments.

Plaintiffs, including the mayor and city council of Ocean City, the mayor and town council of Fenwick Island, and the commissioners of Worcester County, challenged federal approval of US Wind's proposed project that would place 114 turbines off the coast of Sussex and Worcester counties. The suit included eight total complaints; however, three were dismissed on July 2.

More: *WBOC*

CONNECTICUT

Gov. Lamont Commits State to Net-zero Emissions by 2050

Gov. **Ned Lamont** last week signed legislation pledging the state to reach net-zero carbon emissions by 2050.

The first bill set the state's net-zero emissions target and added incentives for solar canopies, energy-efficient heating and cooling systems, green jobs and sustainability-focused businesses. The second included several climate-resiliency measures.

At the same time, Lamont reiterated his support for natural gas and hinted he'd been engaged in talks with the Trump administration and New York officials about building or expanding pipelines that could deliver more gas to Connecticut and the rest of New England.

More: *CT Mirror*

GEORGIA

PSC Approves Temporary Georgia Power Rate Freeze

Under a deal approved by the Public Service Commission last week, Georgia Power's rates will remain the same for the next three years.

Under the agreement reached by the utility and commission staff, base rates will remain the same for three years – except for the cost of recovering from Hurricane Helene. Georgia Power is also scheduled to review fuel costs next year.

More: *Georgia Recorder*

MAINE

Gov. Mills Signs Net-metering Reforms into Law

Gov. **Janet Mills** last week signed a bill into law making community solar and other front-of-the-meter projects ineligible for net metering.

Instead, the Governor's Energy Office will be tasked with developing a successor program for front-of-the-meter net energy billing projects. If the benefits to ratepayers outweigh the costs, then the Public Utilities Commission will need to approve the plan.

Under the state's current law, net-metering customers' tariff rate is tied to the standard-offer-supply rate plus a fixed portion of the transmission and distribution rate. The new law will impose a monthly fee paid by community solar owners to utilities starting January 2026. The rate for distributed generation resources less than 5 MW will then increase by 2.25% every year beginning Jan. 1, 2027.

More: *pv magazine*

NEW YORK

State Begins Review of Previously Rejected Pipeline Project

Natural gas company Williams last week filed an application for public comment with regulators to begin the process of restarting a left-for-dead natural gas pipeline expansion.

The project, called the Northeast Supply Enhancement Line, is a pipeline expansion that extends from Pennsylvania to New York and New Jersey. Williams has resurrected the project, buoyed by executive orders from the White House aimed at boosting fossil fuel production.

More: *WXXI*

NORTH CAROLINA

Gov. Stein Vetoes Bill that Would Have Delayed Clean Energy Goal

Gov. **Josh Stein** last week vetoed a GOP-sponsored measure that would have repealed a Duke Energy requirement to slash carbon pollution 70% by 2030 compared to 2005 levels, while also leaving a 2050 carbon-neutrality deadline intact.

In issuing his veto, Stein pointed to a North Carolina State University study that showed the bill could cause Duke to build less generation capacity over the next decade, just as electricity needs are expected to surge. That means Duke would have to lean harder on aging plants and burn almost 40% more natural gas between 2030 and 2050.

The GOP has the three-fifths majority needed to override the veto in the Senate but is one member short in the House.

More: *Canary Media*

SOUTH CAROLINA

Duke Energy Seeks Rate Increase

Duke Energy last week filed for a $74.8 million rate increase with the Public Service Commission.

Duke is seeking to charge customers for a $90 million share of maintenance to its nuclear power plants, a $34 million share of its gas plants, a $43 million share of hydropower and an $11 million share of batteries for a solar farm. In addition, the company wants to replenish its storm response fund in the wake of Hurricane Helene.

If approved, monthly bills for typical residential customers would increase by $21.66 a month, effective Feb. 1, 2026. The PSC is expected to consider the request in October.

More: *South Carolina Daily Gazette*; *Duke Energy*