ISSN 2377-8016 : Volume 2025/Issue 30 ▪ July 29, 2025

YES ENERGY

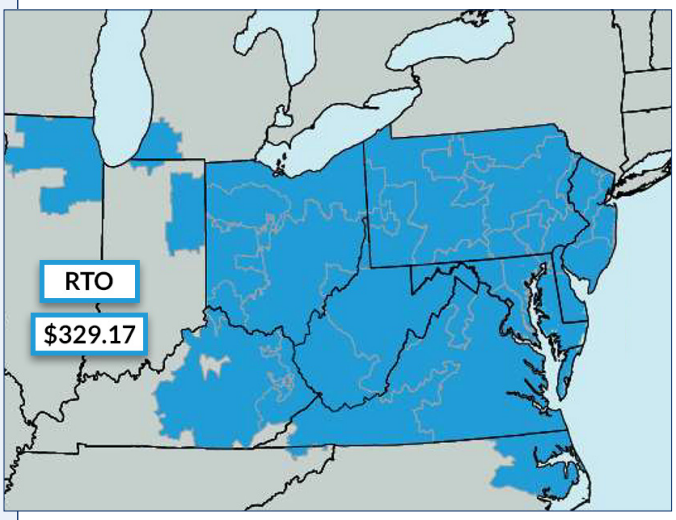
RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

CAISO ▪ ERCOT ▪ IESO ▪ ISO-NE ▪ MISO ▪ NYISO ▪ PJM ▪ SPP

PJM

PJM Capacity Prices Hit $329/MW-day Price Cap



PJM

The 2026/27 capacity auction design has been the subject of several rule changes and FERC complaints, including a settlement between PJM and Pennsylvania Gov. Josh Shapiro to lower the maximum clearing price.

CONTINUED ON P.39

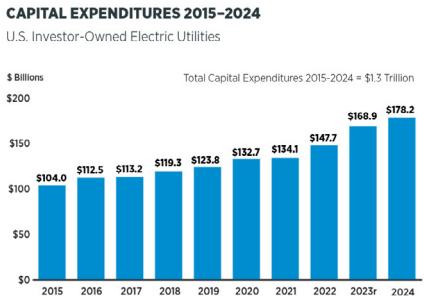
FERC/FEDERAL | MISO | PJM

© RTO Insider

Christie Says Farewell to FERC at Final Meeting as Chair (p.6)

FERC Chair Mark Christie was praised by all of his colleagues for his stewardship of the agency over the past six months, with looming questions over its direction as he departs.

COMPANY NEWS

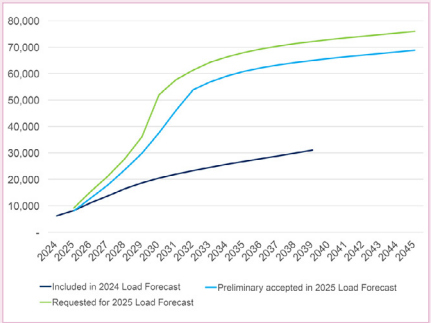


EEI

EEI: Electric Companies Invested $178B in 2024 (p.54)

The data gives scale to the U.S. electric industry, and to the massive capital outlay it plans.

AROUND THE CORNER



PJM

Insufficient Data Center Load Forecasting Likely a Big Part of PJM's Problem (p.3)

Given the magnitude of the costs related to potentially inaccurate demand forecasts, combined with the red-hot politics surrounding the global race to dominate artificial intelligence, it's not hard to imagine PJM's capacity auction results becoming intensely and increasingly politicized.

RTO Insider LLC

YES ENERGY

Editor & Publisher
Rich Heidorn Jr.

Editorial

Senior Vice President
Ken Sands

Deputy Editor / Daily
Michael Brooks

Deputy Editor / Enterprise
Robert Mullin

Creative Director
Mitchell Parizer

New York/New England Bureau Chief
John Cropley

Associate Editor
Shawn McFarland

Copy Editor / Production Editor
Patrick Hopkins

Copy Editor / Production Editor
Greg Boyd

CAISO Correspondent
David Krause

D.C. Correspondent
James Downing

ERCOT/SPP Correspondent
Tom Kleckner

ISO-NE Correspondent
Jon Lamson

MISO Correspondent
Amanda Durish Cook

NYISO Correspondent
Vincent Gabrielle

PJM Correspondent
Devin Leith-Yessian

Western Correspondent
Henrik Nilsson

NERC/ERO Correspondent
Holden Mann

Sales & Marketing

Senior Vice President
Adam Schaffer

Account Manager
Jake Rudisill

Account Manager
Kathy Henderson

Account Manager
Holly Rogers

Director, Sales and Customer Engagement
Dan Ingold

Sales Coordinator
Tri Bui

Sales Development Representative
Nicole Hopson

RTO Insider
2415 Boston St.
Baltimore, MD 21224
(301) 658-6885

See additional details and our Subscriber Agreement at rtoinsider.com.

In this week's issue

Insufficient Data Center Load Forecasting Likely a Big Part of PJM's Problem

By Peter Kelly-Detwiler


Peter Kelly-Detwiler

Mid-Atlantic grid operator PJM has had a rough couple of weeks. On July 16, *it received an open letter* penned by nine bipartisan governors of the 13-state region it serves, citing a "crisis of confidence from market participants, consumers and the states." Admonishing PJM for its "multiyear inability to efficiently connect new resources to its grid and engage in long-term transmission planning," the governors called for fundamental changes and ne

From Bad to Worse: The July Capacity Auction. That was bad enough. But then things got worse, with the release of record high results from the Base Residual Auction for capacity addressing the 2026/27 delivery year.

Last year's auction results already had caused an uproar, as the *clearing price for most of PJM* was set at $269.92/MW-day, up dramatically from $28.92/MW-day the prior year. Baltimore Gas and Electric and Dominion fared even worse, at $466.35/MW-day and $444.26/MW-day. Total costs paid for capacity by all energy consumers soared from $2.2 billion to $14.7 billion in just one year.

2025/2026 BRA Results: A Shock to the System

In response and in an attempt to limit future costs to customers, Pennsylvania Gov. Josh Shapiro (D) negotiated a floor and cap with PJM — eventually blessed by FERC — that would create a price band between $177.24 and $329.17/MW-day for the following two delivery years. (See *FERC Approves PJM-Pa. Agreement on Capacity Price Cap, Floor*.)

Many feared the July 2025 auction would hit the new cap, and it did just that, pegging out in all delivery zones at the same price (good news only for BG&E and Dominion) of $329.17/MW-day. Total estimated cost to load increased as well, from $14.7 billion to $16.1 billion. (See *PJM Capacity Prices Hit $329/MW-day Price Cap*.)

BRA Results for Next Year: Glad Tidings Only If You're a Capacity Resource

Without the cap, it could have been worse. PJM noted in its BRA report that an uncapped simulated auction likely would have cleared at over $388/MW-day. Capacity prices now may be costing customers up to 25% or more of their total bill, raising the questions, "How did we get here?" and "What does this imply for future energy costs?"

The answers to those questions are not simple (though some politicians will try to paint them that way), but they generally come down to the balance between expected supply and forecasted demand.

Supply: An Increasingly Bleak Scenario.

		BRA Resource Clearing Prices ($/MW-day)		
Capacity Type	BRA	Rest of RTO	BGE	DOM
Capacity Performance	2025/26	**$269.92**	**$466.35**	**$444.26**
	2024/25	**$28.92**	**$73.00**	-

Note: Clearing prices in bold indicate constrained LDA

		BRA Resource Clearing Prices ($/MW-day)		
Capacity Type	BRA	Rest of RTO	BGE	DOM
Capacity Performance	2026/27**	**$329.17**	$329.17	$329.17
	2025/26	**$269.92**	**$466.35**	**$444.26**

*Clearing prices in bold indicate constrained LDA; **Cap of $329.17 $/UCAP-MW

Comparison of BRA clearing prices by delivery year by LDA | *PJM*

Why This Matters

Given the magnitude of the costs related to potentially inaccurate demand forecasts, combined with the red-hot politics surrounding the global race to dominate artificial intelligence, it's not hard to imagine PJM's capacity auction results becoming intensely and increasingly politicized.

Among major issues affecting supply, in 2024 *PJM revised* the way it accredited generation resources for their ability to provide capacity during critical peak periods. Nearly every type of resource in PJM's portfolio took a significant hit.

For example, every nameplate megawatt of gas combined-cycle capacity was reduced from 96% to 79%, while that for simple-cycle peakers fell from 90% to 62%. Solar and storage capacity contributions also were revised downward considerably, and even nuclear and coal units were de-rated (from 99% to 95% and from 88% to 75%, respectively). Meanwhile, little additional capacity has been added to the grid recently, with much of that from renewables. Add to that the retirement of several coal units, and dispatchable supply capacity has not kept pace with demand.

Not Much Capacity Being Added to the Mix

Forecasted Rapid Demand Growth: An Unexpected Surprise. The perfect recipe for creating more pricing pressure when supply is limited is to add large amounts of potential new demand, and the addition of data center load does just that. These facilities are large (often well over 100 MW), disconnected from the general macroeconomic environment and extraordinarily difficult to forecast, especially when the majority of current *interconnection requests* to utilities may never actually be served with power. Existing and forecasted data center load

clearly had the potential for a significant impact on the past two auction results. The question is, how much?

In fact, it likely may have resulted in billions of dollars of unnecessary costs to consumers. PJM's Independent Market Monitor *ran alternative scenarios* earlier this year to evaluate this issue and concluded, "data center load growth is the primary reason for recent and expected capacity market conditions, including total forecast load growth, the tight supply and demand balance, and high prices."

The IMM attributed $9.3 billion of the $14.7 billion from last year's auction to data centers, noting, "the inclusion of forecasted data center load increased total revenues by $7,742,157 or 115%." (emphasis added). The IMM further commented, "The role of data center load does not mean that PJM would not have eventually reached a point where supply and demand were tight, but that trajectory was relatively slow and would have resulted in more time to permit market reactions to address the balance of supply and demand."

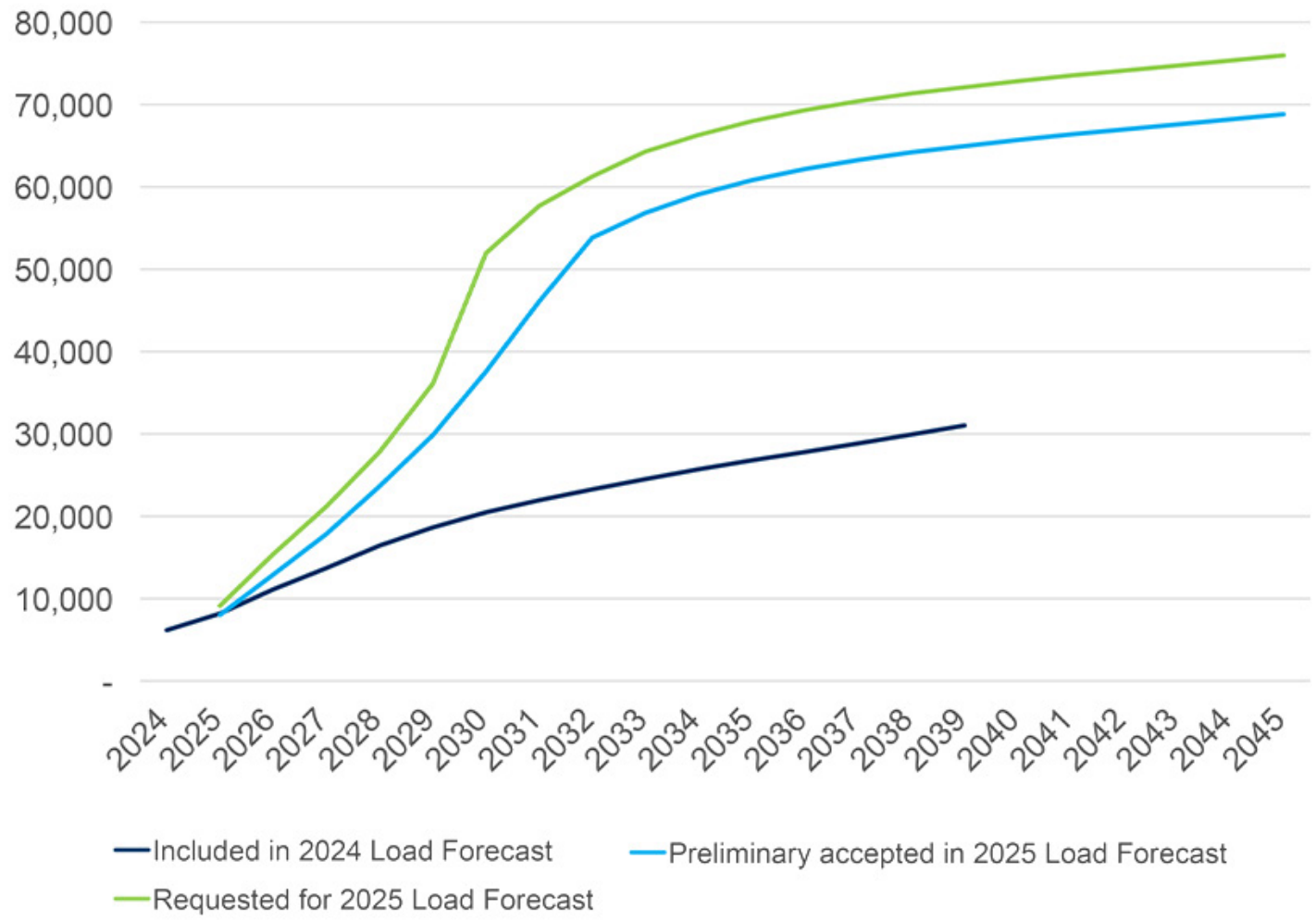
Phantom loads and poor forecasting are likely to create a political firestorm. What the IMM report implies is that if that forecasted future data center load is incorrect, then everybody else ends up paying for a mirage that does not exist. That leads immediately to the more obvious multibillion-dollar question: "How accurate is PJM at forecasting data center loads?"

An analysis of how PJM arrives at its forecast is not very comforting. The grid operator arrives at its number by taking very imprecise utility forecasts that are based on interconnection requests from data center developers and speculators who buy land and place interconnection requests with the eventual goal of selling the projects.

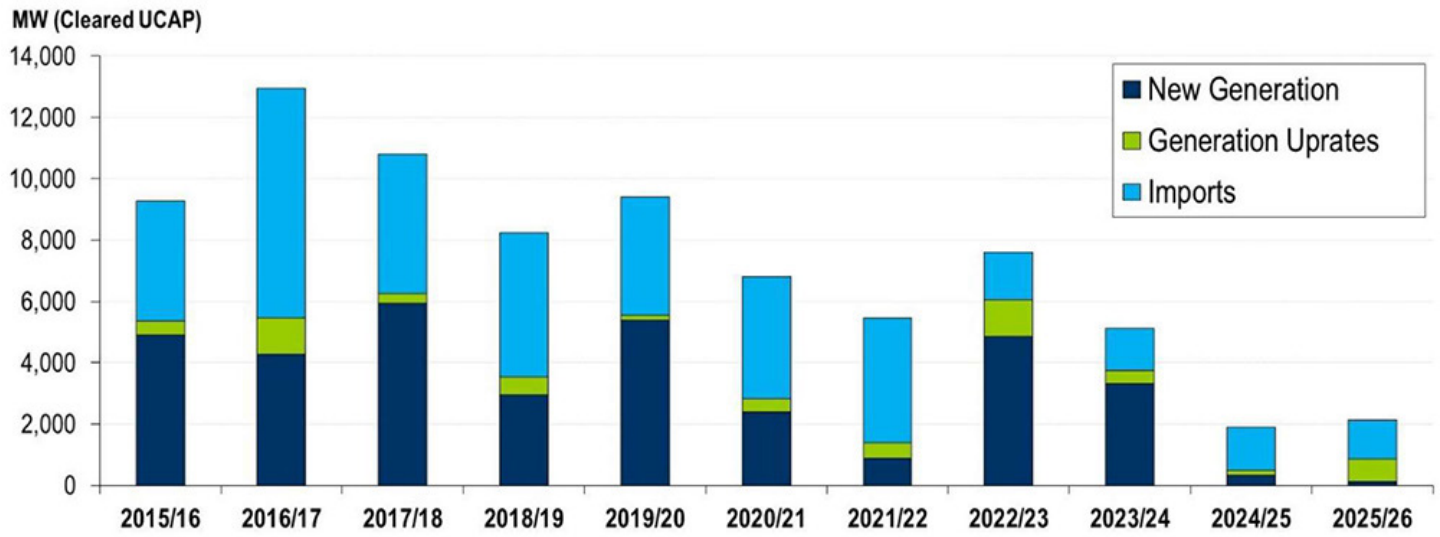
Both types of entities place multiple applications with utilities in multiple states. Their behavior is similar to that of generation asset developers prior to FERC Order 2023 (which required them to put more financial skin in the game, with required deposits and penalties for withdrawing from interconnection queues).

Many developers placed multiple chips on the board, knowing that if one project succeeded, they eventually would withdraw the others. This resulted in highly inflationary supply numbers. In fact, *Lawrence Berkeley Laboratory's 2024 analysis* of interconnection delays reported that for supply assets seeking interconnection between 2000 and 2018, only 19% actually flowed power by the end of 2023.

The data center dynamic is similar enough that some lawmakers and



PJM demand in megawatts | *PJM*



Cleared megawatts (UCAP) by new generation/uprates/imports by delivery year | *PJM*

regulators are catching on. For example, recently passed *Texas legislation SB 6* requires developers of large loads to disclose whether they are seeking similar requests for service elsewhere in Texas (note, that's only in Texas).

It's difficult to say how much inflated load actually exists, but *one report* characterizes this approach of developing multiple requests as a "low barrier, low cost, low risk strategy" employed by developers to access power wherever they can get it. That report also quoted a former Google senior director as saying the numbers could result in "five to 10 times more interconnection requests than data centers actually being built."

Despite this inflationary dynamic, *PJM's 2025 large load forecast* only *minimally reduced the numbers* supplied to it by the utilities in its service territory. While the problem already shows up in the capacity auctions for 2025/26 and 2026/27, this lack of rigor gets worse in the out years when projected data center growth skyrockets.

PJM's Data Center Forecast - Not Much of a Haircut

Not surprisingly, some consumers are worried, especially the more sophisticated and large users with the most to lose. A May 30 *open letter to FERC* from a number of large industrial groups urges the commission to "initiate an independent examination of current load forecasting practices and potential improvements to those practices." That letter cites "the uncertainty and lack of transparency surrounding current load forecasting practices across the country," and the impact it can have on costs.

What's Next? The latest auction signals tough sledding for consumers, with little end in sight. Given the magnitude of the costs related to potentially inaccurate demand forecasts, combined with the red-hot politics surrounding the global race to dominate artificial intelligence, it's not hard to imagine PJM's capacity auction results becoming intensely and increasingly politicized.

The action to address this issue is to employ far more rigor in the forecasting process at the utility level (while ensuring that each utility uses similar processes) and employ a higher level of rigor within PJM's forecasting approach. The second is to do everything possible to accelerate deployment of new capacity in the system.

However, with the next auction less than six months away, don't expect the cavalry to arrive anytime soon. They haven't even saddled up their horses. ■

Christie Says Farewell to FERC at Final Meeting as Chair

By James Downing

FERC Chair Mark Christie presided over his final open meeting July 24, as he plans to step down in the coming weeks after completing work on several orders.

President Donald Trump nominated Laura Swett of Vinson & Elkins to replace Christie as chair. Christie's term ended June 30, but he is allowed to stay until the end of the year as long as his replacement has not been confirmed. (See *Trump Replacing FERC Chair Christie with Laura Swett*.)

Christie started his career in public service in 1994, when newly elected Virginia Gov. George Allen made him a member of his cabinet. He joined the Virginia State Corporation Commission in 2004, where he served 17 years until he was appointed to FERC by Trump during the president's first term.

"After 31 years, it's coming to an end," Christie said. "When I look back at my experience, it's been a hell of a ride. It really has. I've had tremendous opportunities to serve the public, to be in public office, where you get a chance to do good things. And let me just say this, nobody accomplishes anything alone. Whatever you accomplish, others are part of it."

Christie praised the commissioners he served with during his tenure at FERC and his staff, and thanked Allen and Trump.

FERC Chair Mark Christie | © RTO Insider

He also reminisced about what he learned throughout his career. He recalled that during the first major rate case he presided over as an SCC commissioner, he noticed how packed the room was and mentioned the number of people present to the chair.

"He said that room wasn't packed with people," Christie said. "That room was packed with lawyers and lobbyists for every interest group that has money riding on what we do. He said, 'The people who pay the bills for what we do and what we're going to do in this rate case, those people are not in that room. So don't you ever forget the people who are not in that room.'"

The second Trump administration has embraced the "unitary executive" legal theory, which holds that the president can fire members of independent regulatory agencies at will. Asked about it, Christie pointed back to a lesson he learned early at the SCC: that regulators need to worry about the consumers who foot the bill of their decisions.

"There's really no one but us here to be thinking about them and thinking about how what we do affects them," Christie said. "And I hope that everybody who ever sits on this commission always remembers those people's wishes — the millions of people who pay the bills, struggle and worry about whether their lights come on or not."

The SCC is much different from FERC in that it is an agency with its independence recognized in the Virginia Constitution, whereas the federal commission is statutory — created by the Department of Energy Organization Act of 1977 — and is more subject to changes in its legal foundation, Christie said.

Asked about his biggest accomplishment at FERC, Christie pointed to the *regular letters* he has been writing ever since Trump's so-called Department of Government Efficiency sent an email to all federal employees asking them to explain five things they did in the past week.

"When you read those letters, it's just remarkable what we do around here; it's just remarkable. I think it's hard to say what we're most proud of, but being chair, I'm very proud of what we got done," he added. "And those letters really detail the important things we got done every week, every day."

Why This Matters

FERC Chair Mark Christie was praised by all of his colleagues for his stewardship of the agency over the past six months, with looming questions over its direction as he departs.

Those familiar with Christie's dissents on many orders over the years will not be surprised to hear his major regret: that he was not able to cut back on transmission incentives, which he calls "FERC candy."

More specifically, he pointed to a Notice of Proposed Rulemaking that he voted out with former Chair Rich Glick and former Commissioner Allison Clements that would have limited the adder utilities can charge for joining an RTO to just three years and required their choice to join to be voluntary (not required by their state). It never moved forward from the NOPR stage, even through his own time as chair.

"That is something that I regret, that I couldn't get three votes for that," Christie said. "But it just shows … FERC is constantly lobbied, alright? Constantly lobbied. And again, the people paying the bills are not here lobbying or represented. They're just not."

All three commissioners praised Christie, and each of them noted that he reached out to them just after they had been nominated to offer his congratulations and advice.

"A lot of FERC chairs have talked about making FERC boring again, and you, I think, really have achieved that," Commissioner David Rosner said. "We've done a lot of complicated orders. We've done a lot of important work. … The level of consensus is high, and I call that boring, but also the energy nerd here also finds this all very exciting." ■

Opponents Take DOE to Court over J.H. Campbell Retirement Delay

By James Downing

The fight over the U.S. Department of Energy's order requiring Consumer Energy's J.H. Campbell power plant to keep running past its planned retirement in May is in the courts now that opponents have filed lawsuits.

Michigan Attorney General Dana Nessel and nine organizations, including Earthjustice and Sierra Club, filed *separate lawsuits* July 24 at the U.S. Court of Appeals for the D.C. Circuit Court of Appeals after DOE failed to respond to rehearing requests filed at the agency. (See *Order to Keep Campbell Plant Running Challenged at DOE and FERC*.)

"This unprecedented order by the Department of Energy declares an emergency without evidence, completely ignores state and federal regulators that approved the plant's retirement, and will potentially put enormous costs onto utility customers who receive no real benefit," Nessel said in a statement. "I will continue to fight to protect Michigan customers from unreasonable costs imposed by the federal government."

The retirement of the plant has been planned for years, first proposed by Consumers in 2021 and approved by the Michigan Public Service Commission in 2022. The utility had procured replacement capacity and expected its closure would save consumers nearly $600 million, the attorney general said.

"The Trump administration's extension of the J.H. Campbell plant has already harmed local Michigan communities and now could raise energy costs for millions of Americans across the Midwest," Sierra Club Senior Attorney Greg Wannier said in a statement. "We are more than halfway through the so-called 'energy emergency' the administration invented to justify its unlawful order, and as expected, the grid has not needed Campbell around to provide reliable power, even during last month's extreme heat."

The filings are preliminary and ask the court to open a case on the issue, with more substantive briefs coming after that happens.

Why This Matters

DOE's orders to keep two power plants open this summer use the Federal Power Act Section 202(c) in new ways and now the courts will determine whether its actions violated the law.

The petition from Nessel argues that the case is another example of the Trump administration declaring a false emergency as a pretext for advancing its policy agenda outside the means of its normal authority. DOE's initial order will continue to run through August, but Nessel said it could be extended.

In the past, DOE has used its authority to keep plants running under the Federal Power Act's Section 202(c) only when it received a request from the utility running the plant or a local governmental body. Those past orders also were in response to concrete emergencies and subject to limits, so they kept the plants running no longer than needed to address the situation, Nessel's petition argued.

"It was the reasoned judgment of the utility, state regulators, the Michigan AG, and a wide array of ratepayer and environmental interests in Michigan that this old jalopy of a power plant should be retired," Earthjustice Attorney Shannon Fisk said in a statement. "While the administration might not like that fact, a fabricated energy emergency does not give them the authority to saddle Michiganders with the costs and pollution of a coal plant that the utility has already replaced with other resources. The only energy emergency is the one being created by this unprecedented power grab by federal authorities." ■

Consumers Energy's J.H. Campbell coal plant | *Consumers Energy*

NRC Moves Palisades Nuclear Plant Closer to Restart

Transition of Mothballed Reactor to Operating License OK'd; 4th-quarter Operation Eyed

By John Cropley

The Nuclear Regulatory Commission has greenlit the retired Palisades Nuclear Plant's transition back to an operating license.

The July 24 approval is a key milestone on the path to an unprecedented goal — bringing a reactor that had been in line for decommissioning back online and into full service.

It allows Holtec International to receive new fuel at the site and formally transition licensed operators to on-shift status, and it moves the facility closer to a full restart, which Holtec hopes to achieve in the fourth quarter.

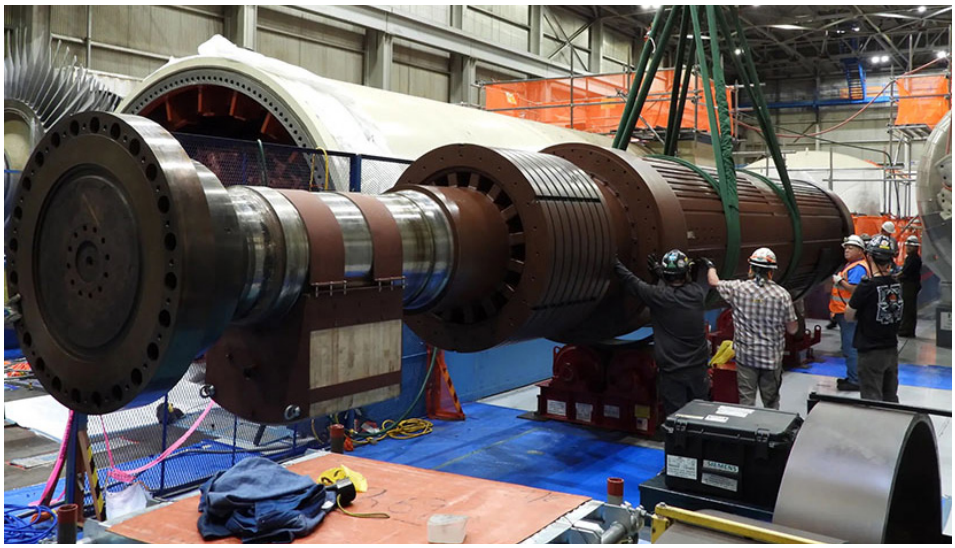
Holtec on July 1 *informed the NRC* that it was ready to transition to the Power Operations Licensing Basis.

The NRC said July 24 it had determined the application complied with regulations, that the facility would operate in conformity with regulations and that operation would not be detrimental to public safety, health and security (*50-255*).

"This is a proud and historic moment for our team, for Michigan, and for the United States," Holtec President Kelly Trice said later in the day. "The NRC's approval to transition Palisades back to an operating license represents an unprecedented milestone in U.S. nuclear energy."

Activists opposed to nuclear energy in general — and to the restart of the aged Palisades plant in particular — had the opposite reaction.

Kevin Kamps of Beyond Nuclear said: "The zombie reactor restart scheme is unneeded, insanely expensive for the public and extremely high risk for health, safety, security and the environment."



The 183-ton main generator rotor is removed for inspection in the turbine building as Holtec prepares its retired Palisades Nuclear Power Plant for a planned restart. | *Holtec*

The NRC's July 24 decision is not the end of the matter, he added: "We will exhaust all administrative remedies at NRC and then appeal to the federal courts. Our fight against this dangerous nuclear experiment on the Great Lakes shoreline is not over."

Further regulatory approvals are needed, but Holtec is making steady progress, with the Trump administration continuing support extended by the Biden administration and ordering the NRC to streamline and speed its review processes.

Holtec plans to follow the Palisades restart with construction of small modular reactors and other advanced nuclear facilities in Michigan and elsewhere.

A wave of reactor retirements swept the industry as facilities aged and their expensive electricity became uncompetitive. Holtec bought three of these retired facilities, then *purchased Palisades from Entergy* in mid-2022, shortly after it ceased operation.

Subsidiary Holtec Decommissioning International would hold the license and be the prime decommissioning contractor.

But with major changes to the energy market on the horizon, Holtec soon decided to instead undertake a restart of the 800-MW plant, first licensed in 1971.

The effort gained momentum in 2023 as Wolverine Power Cooperative signed a *power purchase agreement* for up to two-thirds of the plant's output.

Approximately 600 full-time nuclear workers are on site as the restart effort nears the finish line, along with roughly 1,000 trades workers, vendors and suppliers, *Holtec said* July 17.

The restart effort was unprecedented at the outset but no longer is unique.

There are only two other retired U.S. reactors believed to be candidates for restart.

Constellation Energy is spending $1.6 billion to bring the circa-1974 Three Mile Island Unit 1 back online by 2027. The reactor ceased operation in September 2019 for economic reasons and is being brought back for economic reasons: Microsoft wants its steady carbon-free power for its data centers and is willing to bear the costs.

NextEra Energy shut down its circa-1974 Duane Arnold nuclear plant in 2020 after storm damage but *expressed interest to the NRC* in early 2025 about a potential restart. CEO John Ketchum said recently that engineering studies are progressing favorably, and the company is talking to potential buyers for the electricity it would produce, should it restart. ■

Why This Matters

The regulatory approval is a key milestone in the attempt to pull off the first-ever restart of a retired commercial reactor.

Trump Administration Offers Action Plan and Federal Lands for Data Centers

By James Downing

In an attempt to stimulate the deployment of artificial intelligence and related infrastructure, the Trump administration has released an action plan and announced the development of data centers on federal land.

The U.S. Department of Energy has chosen four sites around the country to host data centers and related energy infrastructure: the Idaho National Laboratory; Oak Ridge Reservation; Paducah Gaseous Diffusion Plant; and the Savannah River Site.

"By leveraging DOE land assets for the deployment of AI and energy infrastructure, we are taking a bold step to accelerate the next Manhattan Project — ensuring U.S. AI and energy leadership," Energy Secretary Chris Wright said in a July 24 statement. "These sites are uniquely positioned to host data centers as well as power generation to bolster grid reliability, strengthen our national security and reduce energy costs."

DOE said it plans to work with data center developers, energy companies and the public in consultation with states, local governments and federally recognized tribes to advance the initiative. Solicitations for proposals to develop the sites will be released in the coming months, and DOE could pick winning proposals by the end of 2025. The department is considering other federal sites for data center developments as well.

The idea to use federal lands for data centers was included in the White House's *AI Action Plan*, which was released on July 23. It also contains some broad recommendations for updates in electricity policy.

"The power grid is the lifeblood of the modern economy and a cornerstone of national security, but it is facing a confluence of challenges that demand strategic foresight and decisive action," the plan said. "Escalating demand driven by electrification and the technological advancements of AI are increasing pressures on the grid. The United States must develop a comprehensive strategy to enhance and expand the power grid designed not just to weather these challenges, but to ensure the grid's continued strength and capacity for future growth."

The plan calls for stabilizing "the grid of today as much as possible," or stopping premature power plant retirements. The existing power grid also can be optimized.

"The United States must explore solutions like advanced grid management technologies and upgrades to power lines that can increase the amount of electricity transmitted along existing routes," the plan said. "Furthermore, the United States should investigate new and novel ways for large power consumers to manage their power consumption during critical grid periods to enhance reliability and unlock additional power on the system."

New, reliable, dispatchable power plants need to be connected, the plan said. And the industry should roll out next-generation technologies such as enhanced geothermal, nuclear fission and nuclear fusion.

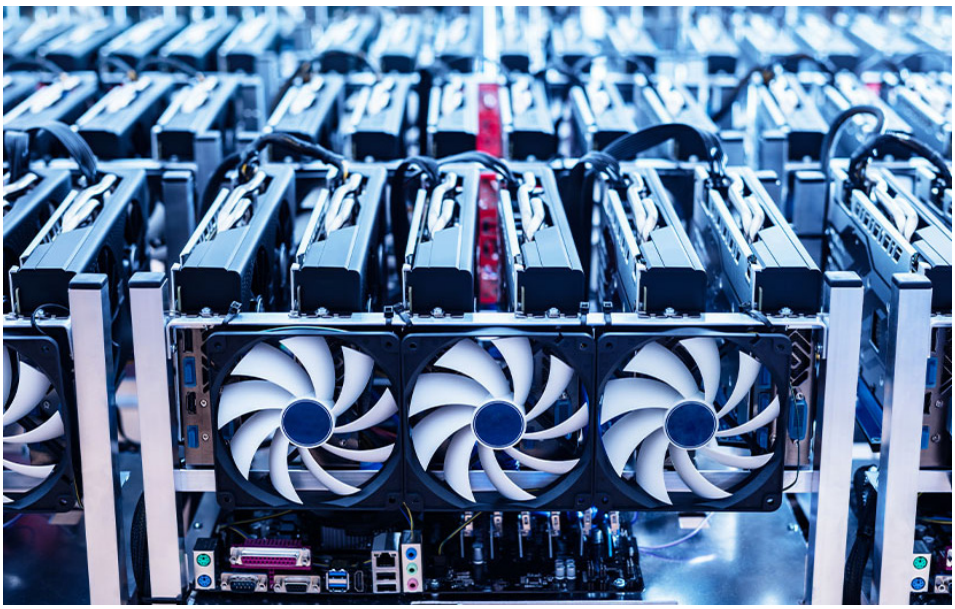
The plan calls for reforming "power markets to align financial incentives with the goal of grid stability, ensuring that investment in power generation reflects the system's needs."

The WATT Coalition and AMP Coalition released a joint statement saying that advanced transmission technologies and grid-enhancing technologies can help in the effort to connect data centers to the grid.

"The Department of Energy found that these technologies together could unlock capacity for more than 100 GW of new power, enough to meet a significant portion of the new load projected over the next five to eight years," they said. "These advanced transmission technologies represent a critical near-term pillar for modernizing the grid and meeting the growing power needs of the U.S. while new large-scale transmission lines are built."

National Electrical Manufacturers Association CEO Debra Phillips called the action plan a welcome development for the industry it represents.

"The plan underscores the criticality of a modernized and resilient power grid, determining that the United States must explore solutions like advanced grid management technologies," Phillips said. "Electrical manufacturers are at the forefront of this transformation — deploying reconductoring solutions, digital substations and data center strategies that optimize grid capacity and enhance reliability." ■



Shutterstock

Senate Hearing Examines Return of Electricity Demand Growth

By James Downing

The return of electricity demand growth is a reality embraced by both political parties, but a Senate Energy and Natural Resources Committee hearing on July 23 highlighted their differences on how to address it.

"Here's the real problem: We have spent much of the last 20 years shutting down the generation that can actually meet that demand," committee Chair Mike Lee (R-Utah) said. "Coal plants retire, nuclear blocked, natural gas tied up in endless litigation; and we replaced a lot of that capacity with wind, solar and batteries, resources that by design don't work all the time."

The growth being driven by artificial intelligence and data centers, electrification and resurging domestic manufacturing will require changes to how energy infrastructure is permitted and built, Ranking Member Martin Heinrich (D-N.M.) said.

"No single business or technical workaround can substitute for a coordinated, modern, responsive grid," Heinrich said. "Fortunately, we sit on the committee that can help make that happen. The urgency isn't just about maintaining our edge in AI innovation; it's about affordability."

The recently passed reconciliation bill cut tax credits for the kind of energy resources that can be most quickly deployed — solar and wind, which Heinrich said would raise nationwide annual energy costs by $16 billion by 2030 and $33 billion by 2035.

"And the president's tariffs are driving up equipment costs, raising the cost of all energy generation resources — all of them," he added. "This is leading directly to Americans spending more on their utility bills."

Lee pushed back on criticism about Republicans using reconciliation and relying on party-line votes to cut renewables subsidies in the recently passed One Big Beautiful Bill Act, reversing policies Democrats had enacted three years earlier using the same legislative tactic.

"The Inflation Reduction Act turbocharged subsidies for wind and solar," Lee said. "And those subsidies are distorting energy investment, because the subsidies can offset more than 50% of the project's costs — a significant amount that ends up being borne by the U.S. government and the U.S. taxpayer."

On top of that, he added, those intermittent resources need to be balanced with energy storage or natural gas peaker plants, which add to the costs.

Huntsman Corp. CEO Peter Huntsman agreed, pinning the blame for the decline in its chemical industry on its net-zero policies.

"I've experienced this firsthand as our

Why This Matters

Congress holds hearings like this to collect information that could be used to inform legislation down the road. After failing to pass last year, permitting legislation could come up again at some point.

Huntsman Corp. CEO Peter Huntsman, Vantage Data Centers Vice President Jeff Tench and Grid Strategies President Rob Gramlich testify before the Senate Energy and Natural Resources Committee on July 23. | *Senate ENR Committee*

company has laid off thousands of employees in Europe," Huntsman said. "Facilities that were globally competitive just a few years ago have been closed and are no longer operating due to ruinous and unrealistic net-zero and decarbonization policies and the failed ideas that you can power a modern economy without developing oil and gas resources."

No AI Leadership Without Power

Jeff Tench, executive vice president at Vantage Data Centers, offered the perspective of his industry, saying that, just five years ago, a data center with 30 MW of power demand would've been considered "large." Now, 100 MW is a starting point, and some customers are asking for 1 GW or more for data centers used to support artificial intelligence, he said.

"We cannot get the amount of electricity we need in the time frame to build our data centers," Tench said. "Without electrical power, it is not possible to build digital infrastructure — the infrastructure that supports AI data centers. Transmission lines and generation facilities must scale rapidly if the U.S. is to remain the global leader in AI innovation. We are asking for your leadership to drive a more modernized policy framework that reflects today's growth, aligns with investment timelines and ensures that the power system is ready when and where it is needed."

Interconnection timelines for both new generation and new large loads are too slow, the transmission grid needs to be upgraded to support the new demands, and permitting must be improved to ensure the U.S. can lead in AI development, he added.

"The United States is looking at an AI era that is not coming, but is here," Tench said. "We have the capital, we have the customers and the talent, but we will not lead if we cannot power it."

Power demand growth is sudden and challenging to meet, and it is contributing to affordability issues around the country, said Rob Gramlich, president of Grid Strategies. While acknowledging the need for more generation, Gramlich focused on transmission first because the federal government has more authority over its development.

"It has the highest impact," Gramlich said. "It's the great integrator of all resources. It may seem like it's a renewable energy piece of infrastructure, but that's just because over the last five years, that's all anybody was trying to connect to the grid.

"Right now, we're seeing a lot of other things trying to connect to the grid, including Jeff's data centers and data centers around the country, other large loads, manufacturing and other types of generation. And whether it's nuclear, [carbon capture and sequestration], other types of generation — guess what? It's going to face that same constrained grid."

Building new lines can take time, but grid-enhancing technologies and advanced conductors can be deployed more rapidly to get more out of existing infrastructure, Gramlich said. The industry should also keep considering building larger 765-kV lines, which are cheaper compared with building multiple lines to meet the same need, Gramlich said.

"We do need firm power to meet peak loads," Gramlich said. "Resources provide varying levels of contributions to meeting peak loads. Nuclear has the highest contribution at 95%, but we're not able to get much more very soon. Gas CTs, at least according to PJM, are around 60% in terms of their ability to serve peak loads. Combined cycle is a little higher in the 70s. Offshore wind is actually 69%.

"And so none of these resources are perfect, but the point is, when you put them all together on the integrated grid, that's how you get nearly 100% reliability of the power system." ■

FERC-State Collaborative Examines RTO/ISO Governance Issues

PJM State Regulators Express Most Concern About Organized Market Processes

By James Downing

FERC and state regulators examined issues around ISO/RTO governance during a July 27 meeting of the Federal-State Current Issues Collaborative in Boston, with members from PJM pushing for the biggest changes on that front.

The issue has come to life in PJM as part of a focus on affordability and resource adequacy issues, which have recently led some stakeholders to call for states to get the ability to appoint RTO board members. (See *State Governors Seeking Ability to Nominate 2 Members to PJM Board*.)

Pennsylvania Public Utility Commission Vice Chair Kimberly Barrow said it would be impossible to tackle RA issues facing PJM and other markets absent reforms.

"We cannot come up with a durable — and I do emphasize durable — solution for it unless we change, fix [and] adapt the governance structures in the RTOs," Barrow said.

PJM's governance structure, and other rules, were developed when the RTO was long on generation, but that situation is not going to return anytime soon.

"Governance rules cannot be orthodoxy," Barrow said. "They have to adapt to reality. And the RTO, frankly, has to adapt to the changes in the states that form the RTO in the first place."

Barrow supports the existence of RTOs, saying they lead to efficiencies and bring down costs for customers, but she thinks their rules could be simplified and become more responsive to their member states.

Governance is important in PJM with the very different positions among its states, which can be either net exporters or importers of power and operate under varying economic and environmental regulations, Barrow said.

"Currently, today, the states are outgunned," Barrow said. "We are outspent. We're outmatched when it comes to being heard at the RTO."

That could be fixed if the states were given a better role or the board was given more independence from the stakeholders, she added.

'Nothing Ever Gets Taken Away'

The time required to monitor all the activities in RTO/ISO processes can prove daunting, said Michigan Public Service Commissioner Katherine Peretick, whose state sits largely in MISO but has some territory in PJM.

"It's really time-consuming and it's really complicated, and it's changing," she added. "The rules, change, the format of everything changes. More things get added. Nothing ever gets taken away. And it's really difficult to keep up with this from the state level. The well-funded organizations that are members of these RTOs have lots of money to spend on participating in these — they can hire additional people."

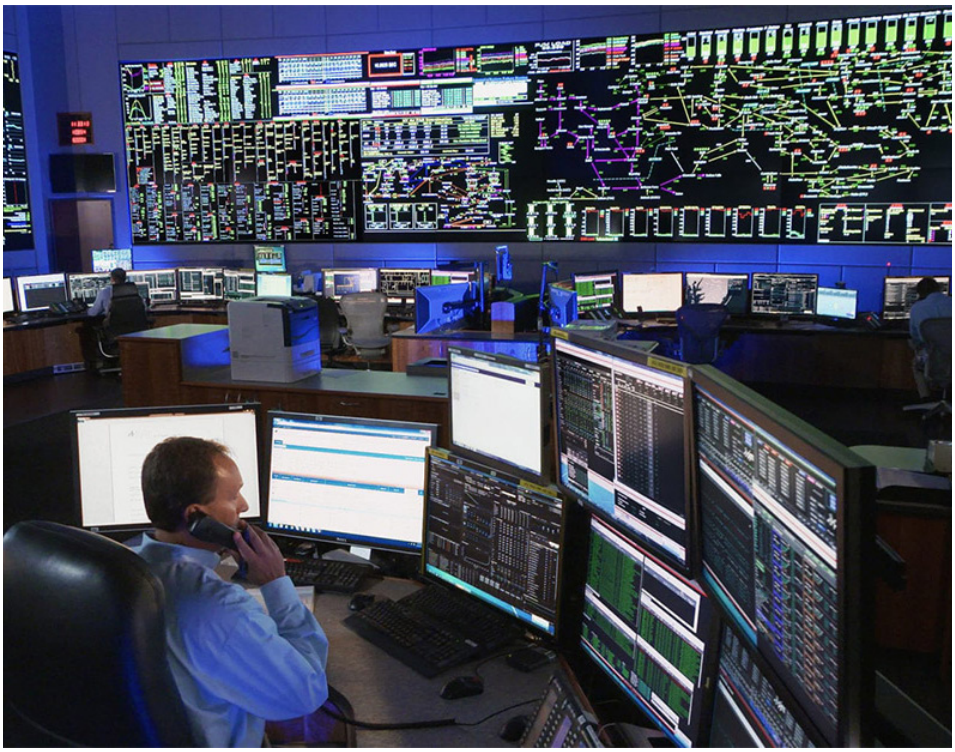
But state regulators have limited budgets and cannot devote as much effort to the stakeholder process as the industry, she said.

FERC Chair Mark Christie agreed that states are generally outgunned in RTO processes and noted how hard it is for their staffs to follow every issue going through the stakeholder process. And while that proved impossible for state commission staffs in PJM, they developed a solution.

"We set up OPSI, the Organization of PJM States, early on," Christie said. "And most importantly, we were able to get a tariff

Why This Matters

States are pushing for a bigger role in RTO/ISO governance and the stakeholder process as they play a growing role in addressing looming resource adequacy issues in PJM and other markets.



PJM

change to fund dedicated staff for OPSI."

Without OPSI staff getting paid to monitor the stakeholder process, state regulators would be hard pressed to keep up with the RTO, he added.

FERC has been responsive to state concerns, and that has contributed to PJM listening as well, Ohio Public Utilities Commissioner Dennis Deters said.

"We need to take a hard look at governance," Deters said. "The PJM structure with a large membership, where you've got supermajority rules that drive a lot of the major decision-making should be of great concern to all states, but specifically, states like Pennsylvania and Ohio, which have given the resource adequacy keys to their RTO."

Deters said the decision-making process in PJM can be opaque and has been reactive, and many of the RTO's responses to RA problems have been temporary.

Taking Away the Mystery

And while PJM commissioners complimented some recent changes in ISO-NE, which has worked more closely with states in recent years, New England regulators want to see additional changes.

"On resource adequacy, it's really important that the states work closely and build a strong relationship with ISO New England to make sure that if there are problems that are identified, that analysis is shared with the states in a timely way, in a consistent way, so that the states can take appropriate action," said Maine Public Utilities Commission Chair Philip Bartlett. "I think we're making some positive moves on this front. ISO-New England has really started doing a lot more robust analysis."

Maine is trying to develop onshore wind resources in the northern part of the state, which lacks transmission, with plans to connect 1,200 MW. Bartlett said it would make sense for the RTO to do long-term planning, which could identify a larger need for wind fromNorthern Maine, allowing state commissioners to work on developing transmission to bring up to 3,000 MW to the RTO's markets.

Another change that could benefit New England: a more open and transparent stakeholder process, which is currently conducted by NEPOOL. Bartlett said it would be helpful for the organization to open its meetings to the public.

"This seems like an important way to help build trust and confidence in the work that's happening," Bartlett said. "Anytime we can let people in and sort of peek behind the curtain, I think it takes away some of the mystery or the concern about decisions being made in a back room, and they can really see the complexity of the issues we' dealing with and the thoughtfulness that I think all the stakeholders in the region engage in to try to tackle those problems." ■

CPUC OKs New PG&E Rule to Speed Tx Connections for AI Data Centers, Others

Opponents Say Rule Doesn't Fully Evaluate Ratepayer Impact

By David Krause

The California Public Utilities Commission on July 24 partially approved a new rule that will make it easier for artificial intelligence data centers and other large customers such as electric vehicle charging stations to interconnect projects in Pacific Gas and Electric's territory.

PG&E in November 2024 applied to the CPUC for approval of the new retail tariff, Electric Rule 30, saying it had received 40 interconnection applications since 2023. These new applications have increased PG&E's retail customer interconnection demand by more than 3,000%, utility representatives said.

"Given the unprecedented number of pending transmission-level service connection applications received between 2023 and 2024 that are awaiting negotiations with PG&E for retail service at transmission-level interconnection, it is reasonable to consider an interim implementation of Electric Rule 30," the CPUC said in its decision, which temporarily approves the rule for transmission customers willing to foot the costs for needed upgrades ahead of a final decision by the agency (*24-11-007*).

The rule will allow transmission customers who provide advance payments and voluntarily commit to prefunding up to 100% of their needed network upgrades to bypass previously required procedures, speeding up their interconnection times.

Why This Matters

AI data centers are demanding more power than ever — and on rapid timelines. The CPUC's approval of PG&E's new rule signals the agency is willing to accommodate those demands.

In its application to the CPUC, PG&E contended that, without the new tariff, it must engage in lengthy one-on-one negotiations with those customers, often leading to "non-typical/exceptional" case filings that require the time and resources of the utility, the customer, the commission and other stakeholders.

The CPUC has historically required PG&E to complete an advice letter and case filing process for large transmission connection projects.

PG&E said the new rule would eliminate those negotiations, standardize the process and provide faster service for large load customers, while providing rate benefits and lower monthly bills for existing customers.

"This decision allows for interim implementation [of Electric Rule 30] for transmission-level customers who provide advance or actual cost payments and voluntarily prefund up to 100% of specific transmission network upgrades," CPUC Administrative Law Judge Manisha Lakhanpal said in a June proposed decision recommending the agency approve the rule. "The decision requires new transmission-level customers seeking retail services to be responsible for the initial costs of all transmission facilities, rather than those costs being borne by ratepayers."

The new rule applies to large transmission customers sized 50 to 230 kV and the following types of transmission facilities:

- Type 1: Transmission Service Facilities
- Type 2: Transmission Interconnection Upgrades
- Type 3: Transmission Interconnection Network Upgrades
- Type 4: Transmission Network Upgrades

Eligible transmission customers must provide advances and cost payments for Type 1-3 facilities and a 100% pre-funded loan for Type 4 facilities, the decision says.

Shutterstock

The decision deferred PG&E's request for refunds on Type 1-3 facilities; repayment of pre-funded loans and interest provisions; and repayment of loans for Type 4 facilities. A decision on these matters will be included in the CPUC's final decision.

PG&E had said if the CPUC denied its application, pending transmission connection applications regarding service requests would not be directly affected.

Cal Advocates, The Utility Reform Network (TURN) and the Joint Community Choice Aggregation group opposed the decision, saying PG&E's proposal is "unjustified, premature and rushes the procedure without fully evaluating the impact on ratepayers."

PG&E shareholders, rather than ratepayers, should be responsible for Electric Rule 30 costs because PG&E has not substantiated prospective benefits, Cal Advocates, a public agency, said about the decision.

TURN said the massive size of the data center load "increases the likelihood of causing or accelerating the need for expensive transmission system upgrades, which would be recovered primarily from other customers under PG&E's proposal." About 70% of the transmission-level service connection applications are data center load, the decision says.

The CPUC rebuffed the consumer groups' concerns but agreed the cost implications of the new Electric Rule 30 are unknown. ■

Robert Mullin contributed to this article.

BPA Customers to See Increased Power, Tx Rates

By Robert Mullin

Bonneville Power Administration customers' power rates will increase by about 8 to 9% over the next three years, while transmission rates will jump by an average of nearly 20%, the agency said July 24.

The agency published the rates in its final *record of decision* (ROD) for the BP-26 rate period covering the 2026/28 interval, which BPA says will be a one-time deviation from its typical two-year interval for rate-setting.

"Lower than initially anticipated, the final rates for fiscal years 2026, 2027 and 2028 follow more than a decade of holding increases at or below the rate of inflation — an accomplishment that stands out among the rising rates of regional utilities during the same period," the agency said in a *statement* announcing the decision.

"We appreciate the incredible collaboration with our ratepayers across an array of power-, transmission- and tariff-related matters," BPA Administrator John Hairston said in the statement. "We've developed a bedrock of support for the programs, projects and initiatives we're implementing as Bonneville continues to meet the power and transmission needs of our utility customers, and to provide reliable, affordable and safe electricity to Northwest communities."

BPA's power rate schedule consists of multiple categories of primary rates for federal energy sales, which include the:

- Priority Firm power rate, or "Tier 1," which applies to firm power sales to BPA's public body, cooperative and federal agency customers;
- Industrial Firm power rate, which is applicable to firm power sales to direct service industrial customers; and
- New Resource Firm power rate, which applies to firm sales to investor-owned utilities and public customers serving new large loads.

BPA's Bonneville Dam | *U.S. Army Corps of Engineers*

What's Next

The changes will be effective Oct. 1 and remain in effect until Sept. 30, 2028. Specific to rates, BPA will file the case with FERC, requesting interim approval for the rates while awaiting final FERC approval.

Tier 1 "non-slice" contracts represent most of BPA's power sales. "Non-slice" refers to a type of contract in which the customer is guaranteed a specified volume of energy regardless of conditions on the hydro system; in contrast, total volumes delivered to "slice" customers can vary based on availability.

In its statement, BPA said the "average effective increase" for Priority Firm Tier 1 power rate will be 8.9%, compared with an initial proposed increase of 9.8%, while transmission rates will increase by an average of 19.9%.

An appendix in the ROD provides greater detail, saying BPA staff will work to deliver a Tier 1 "non-slice" effective power rate no higher than $38.59/MWh, representing an increase of about 8.3% above current rates.

For other categories, the appendix says, BPA "commits to produce rates no higher than $0.5/MWh above" the "indicative rates" of $37.96/MWh for Priority Firm Tier 1, $45.92/MWh for Industrial Firm and $111.99/MWh for New Resource Firm.

"These rates will also enable the advancement of critical initiatives to meet our customers' needs and support national priorities for more abundant, reliable and secure energy," Hairston said in a preface to the final decision. "From implementing new long-term power sales contracts to pursuing day-ahead market participation and advancing major power and transmission investments, the work we accomplish over the next three years will be critical to the long-term success of BPA, our customers and the region we serve." ■

New WRAP Task Force to Take on Treatment of CAISO Tx

By Robert Mullin

A new Western Resource Adequacy Program task force has been charged with revising the WRAP tariff to clarify that participants can rely on a specific category of CAISO transmission service to count remote resources toward their "forward showing" requirements under the program.

While CAISO and California's non-CAISO utilities, already subject to a state-run RA program, are not participating in the WRAP, California's grid is likely to function as the key "wheel-through" corridor for RA sharing among the WRAP's Northwest and Desert Southwest participants due to the shortage of alternate routes.

Creation of the CAISO TX Task Force came at the suggestion of Salt River Project (SRP), which last year raised the concern that CAISO's description of its own firm transmission product as "high-priority wheeling-through" is not recognized anywhere in the tariff of the WRAP, a reliability program administered by the Western Power Pool (WPP) and operated by SPP.

That means the tariff does not explicitly equate CAISO's firmest offering of transmission service with NERC's Priority 6 or 7 transmission service levels, the minimum level of service the WRAP requires for a participant to count a distant resource toward its RA obligation.

"This creates ambiguity as to whether CAISO high-priority wheeling-through qualifies as firm transmission under WRAP. This creates uncertainty for participants relying on CAISO high-priority wheeling-through transmission to satisfy WRAP requirements," SRP wrote in a tariff change request form included in WRAP's *2025 Work Plan*, which was developed by the WRAP Program Review Committee and approved by the WPP's Board of Directors in June.

The WRAP's CAISO TX Task Force is working to ensure that program participants can use the ISO's transmission grid to meet forward showings. | *© RTO Insider*

"Without clear recognition, participants may experience compliance risks despite securing the highest available firm transmission from CAISO," SRP wrote.

SRP's proposed solution: to introduce tariff language "that provides clarity on what qualifies as qualifying transmission to evaluate transmission products that do not explicitly use NERC Priority rating."

The utility said the change should resolve "uncertainty around transmission compliance" and give participants "confidence that high-priority transmission products that do not use a NERC Priority rating will satisfy WRAP requirements, which will streamline compliance."

Speaking during a July 23 meeting to kick off the effort, Maya McNichol, a WPP policy and engagement manager, said WPP considers the CAISO TX Task Force to be an "easy" initiative that should be concluded after three or four meetings over two months.

"The goal here is to ensure … that WRAP participants can use CAISO high-priority wheeling-through transmission as part of qualifying transmission when doing all of the WRAP things that require transmission," McNichol said.

She said the WPP thinks the best approach would be to add a new "WRAP qualifying transmission" definition to the tariff that includes a reference to CAISO's "high-priority" service, then substitute that definition for any relevant references to "firm transmission" or "forward showing transmission requirement" throughout the WRAP tariff and business process manual.

At the meeting, task force members elected Jerret Fischer, SRP senior market operations strategy analyst, as the group's chair.

The task force will meet next Aug. 1. ■

Why This Matters

The WRAP CAISO TX Task Force will take on the issue of ensuring that resources relying on "high-priority wheel-throughs" on the ISO's grid can be recognized in program participants' forward showings.

Colorado Commissioners Spar over PSCo's Markets+ Choice

Questions Arise over Utility's Cost to Participate in SPP Market

By Elaine Goodman

The Colorado Public Utilities Commission will soon decide whether to allow Public Service Company of Colorado (PSCo) to join SPP's Markets+, but commissioners on July 23 had differing views on whether the move would be in the public interest.

A decision is now expected during the commission's July 30 meeting. In addition to seeking CPUC approval to join Markets+, the utility is also asking to recover costs associated with joining Markets+ through the electric commodity adjustment tariff.

Markets+ has been in a heated battle for participants with CAISO's Extended Day-Ahead Market (EDAM).

During the July 23 meeting, commission Chair Eric Blank said he'd vote to approve PSCo's application. He sees the company's participation in Markets+ as a way to integrate Colorado's two balancing authorities, run by PSCo and the Western Area Power Administration (WAPA). WAPA's Rocky Mountain Region intends to join SPP's RTO West. (See *WAPA, Basin Electric Commit to SPP's RTO West*.)

Blank also sees value in joining Markets+ related to resource adequacy, greenhouse gas accounting and wholesale market price transparency. Those benefits don't necessarily show up in production cost modeling used to assess the day-ahead market, he said.

"I can't support denying the application and doing nothing," Blank said. "In my view, we just need to keep the funding in place and to keep pushing the two Colorado balancing authorities together on the operational side as best we can."

Commissioner Megan Gilman said she was concerned that the benefits of joining Markets+ wouldn't outweigh the costs. Cumulative net costs are expected to be around $30 million by 2031, she said.

Blank argued that the amount was small relative to the utility's overall spending in areas such as wildfire mitigation, distribution system upgrades and capital expenditures.

Colorado PUC Chair Eric Blank, bottom left, and commissioners Tom Plant and Megan Gilman are joined by commission adviser Gerald Deaver, top left, during the commission's July 23 meeting. | *Colorado PUC*

"Why are you relying on a couple million dollars here versus there given the bigger issues at stake here?" he said.

But Gilman didn't seem convinced.

"This decision should stand on its own," she said. "If we're entering a market, it should be because it provides net benefits to Colorado consumers. And I'm just not seeing that represented appropriately in the evidentiary record."

In terms of resource adequacy, Markets+ will require participants to join Western Power Pool's Western Resource Adequacy Program (WRAP). Gilman said PSCo could choose to join WRAP without joining Markets+.

"In evaluating the resource adequacy concerns, I'm not sure where that leads to Markets+ being the only solution and it certainly is an expensive solution," she said.

RTO Implications

Looming over the discussion was *Senate Bill 72* of 2021, which requires electric utilities that own and control transmission facilities to join an organized wholesale market by 2030. The bill defines an organized wholesale market as an RTO or ISO.

Commissioner Tom Plant said projections show that through 2042, the expected benefits of joining Markets+ would exceed costs by about $17 million. But from now until 2030, when utilities are required to join an RTO, "that doesn't come out positive," Plant said.

There are expenses that must be paid whether or not PSCo stays in Markets+, he said, along with around $13 million for software that might not be transferable to a different market.

"Direct cost benefits between now and when we are supposed to join an organized wholesale market seem to be clearly under water," he said.

Complicating matters is that PSCo could file a petition for a waiver from the RTO requirement as allowed under SB 72 — a move some commissioners are expecting.

"If we — you — deny this petition [to join Markets+], I just think work on integrating the two balancing authorities in Colorado ends," Blank said to his fellow commissioners.

Governance, GHG Accounting

PSCo, an Xcel Energy subsidiary, filed its request to join Markets+ in February. (See *PSCo Seeks to Join SPP's Markets+*.)

PSCo is seeking recovery of about $2 million in Phase 1 costs through the electric commodity adjustment tariff. Cost recovery would also include Phase 2 expenses, consisting of about $14 million in administrative fees during the first five years of market operations and about $13 million to $15 million for technology upgrades.

The CPUC held an evidentiary hearing on the matter on May 27-28.

PSCo said it was drawn to Markets+ because of its independent governance, GHG emissions tracking and accounting system, and benefits "overall and in relation to costs relative to the other markets studied, including EDAM."

But a study commissioned by the Environmental Defense Fund said PSCo would receive millions of dollars more in annual benefits from participating in EDAM rather than Markets+. (See *Study Finds PSCo Would Gain More in EDAM than Markets+*.) ■

‘Mark Twain’ Summer Weather Eases CAISO’s Grid Operations

But More Active Wildfire Season Keeps Calif. on Alert

By David Krause

Below-average temperatures in California this summer have reduced demand and made electric grid operations uneventful so far, with the state reaching 40,000 MW of demand for the first time in July, CAISO CEO Elliot Mainzer said during a July 23 meeting of the ISO’s Board of Governors .

Conditions have been favorable for grid operations across CAISO’s footprint: average temperatures in June were near normal, while temperatures in the first part of July were below normal, Mainzer said.

“To [board] Chair [Severin] Borenstein, I say we are about halfway through 2025 and your attire today is indicative to a certain degree of the type of summer we are having in the Bay Area … a Mark Twain summer,” referring to the famous quote often misattributed to the author: “The coldest winter I ever spent was a summer in San Francisco.”

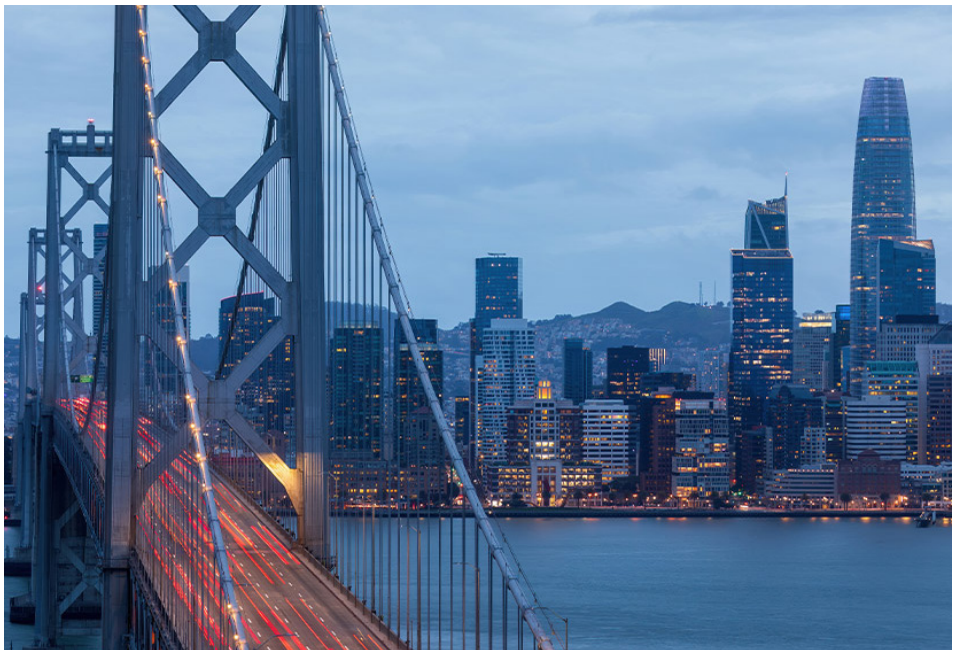
In general, CAISO has avoided any major disruptions this year, but the region has August and September to go — the months that tend to offer the greatest grid challenges, Mainzer added.

Although electricity demand has been lower than average, this year’s wildfire season is well ahead of last year’s pace in both frequency and severity, Mainzer said.

As of July 1, 3,938 wildfires had occurred in California, compared to 3,339 over the same time last year. Acres burned is up substantially too: 182,497 acres this year so far compared to 76,152 last year. The five-year average for this time of the year is about 46,000 acres.

Why This Matters

Summer typically brings peak loads due to air conditioning use, but so far in California, temperatures have been below average this year.



Shutterstock

California is set to meet electricity demand this summer under normal conditions, but in a worst-case scenario, the state could need to use more than 2,600 MW of contingency resources, according to a CAISO *report* in May. Wildfires outside the state could reduce import capacity by as much as 4,000 MW, the report says.

AI Pilot Program Begins

Mainzer said also that CAISO is implementing an AI pilot program — called Genie — to support control room operations. The program will specifically help with facility maintenance requests and act as a “co-pilot” tool to enhance efficiency, Gopakumar Gopinathan, CAISO senior adviser of power systems technology, said in an email to *RTO Insider*.

Genie can detect anomalies in maintenance requests and identify which transmission paths may be affected under certain scenarios. The AI program relies on historical data, operating procedures and related information sources to deliver clear, context-rich insights to operators, Gopinathan said.

Genie is not meant to replace human decision-making tasks, Gopinathan said.

“While the AI prototype can identify anomalies in maintenance requests, extract operational insights, and recommend next steps, all decisions remain under the direct oversight and authority of CAISO operators,” he said.

Genie is being developed with Open Access Technology International as part of CAISO’s control center modernization efforts and is not, at this time, implemented in a real-time environment, he said.

“For now, the AI remains in testing mode, and no recommendations generated by the AI are being used in live operations,” Gopinathan told *RTO Insider*. “If the pilot meets performance expectations, this technology is expected to significantly enhance the support available to system operators, particularly in tasks that are repetitive and time consuming.”

When asked if Genie will be used to help control room operators make real-time decisions about electricity flow on the grid, Gopinathan said the AI currently does not perform this task. ■

Battery Storage Revenue Average Trending Down in California

But Construction of Storage Projects not Slowing Anytime Soon

By David Krause

California's fastest-growing energy resource — battery storage — is earning less net revenue per unit with each passing year, while capacity is expected to continue to boom in the Golden State.

Battery storage net revenue dropped from an average of $102/kW-year in 2022 to $78/kW-year in 2023, to $53/kW-year in 2024, indicating a "trend," CAISO's Department of Market Monitoring (DMM) said in a July 15 *memo*, which was included in reports provided to the July 22 general session of the Western Energy Markets Governing Body.

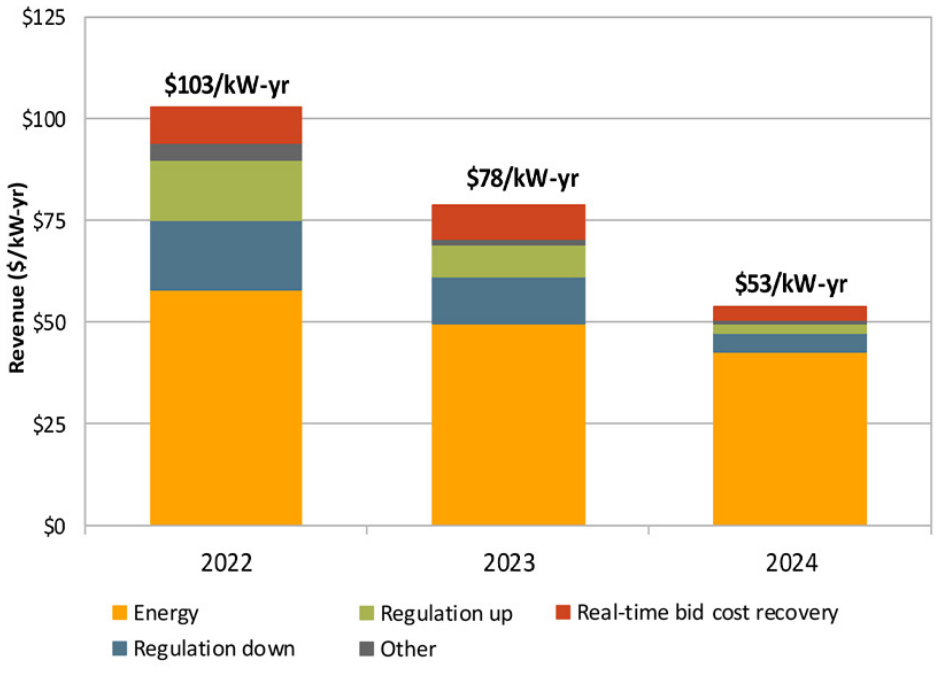
Lower peak energy prices are the primary cause of the revenue decline, and revenue from ancillary services has also continued to decrease significantly as the volume of battery capacity has increased, the DMM said.

Even so, an additional 14,000 MW of battery storage capacity is planned to be online by 2030, pushing CAISO's total to about 28,000 MW by that year. Battery storage capacity has gone from 500 MW in 2020 to close to 14,000 MW as of June.

Nearby states are also going bonkers over batteries: Arizona plans to install more than 5,000 MW of additional battery storage capacity by 2028, while Nevada is looking to add about 2,500 MW by that year. In total, more than 19,000 MW is planned to be installed in Western Energy Imbalance Market (WEIM) states by 2028, DMM Executive Director Eric Hildebrandt said in the memo. Much of the battery capacity in other WEIM states is being installed to meet the renewable energy requirements of load-serving entities in California, Hildebrandt said.

The DMM recommended CAISO revise its bid cost recovery rules for batteries because the current rules "significantly decrease the incentive for batteries to bid in a manner that ensures their capacity is usually fully available during the most critical peak net load hours," Hildebrandt said in the memo.

"In addition to increasing bid cost recovery payments and related gaming opportunities, this can result in batteries being discharged prior to the peak net load hours, when battery capacity is needed most," Hildebrandt said.



Average revenue for batteries in CAISO that have operated for more than one year | *CAISO DMM*

Why This Matters

Industry participants are likely to closely watch the financial fortunes of battery storage operations in California, which has the most developed market for the resources in the U.S.

In 2024, battery storage facilities in CAISO's region received about $18 million in real-time bid cost recovery payments, representing 11% of total bid cost recovery payments and 4% of batteries' total net market revenues.

Batteries tend to contract less than their maximum power capacity for resource adequacy purposes. This means batteries could theoretically provide more power than their RA value, Hildebrandt added.

During the five highest load days of 2024, battery storage resources provided significant RA capacity. However, RA storage capacity can drop in the later peak net load hours — when batteries are critical for system reliability — because of insufficient state-of-charge, Hildebrandt said.

In 2024, batteries supplied about 9% of CAISO's energy during peak net load hours, while battery charging represented about 15% of CAISO's load during midday hours, according to the memo. Battery charging helped reduce the need to curtail or export surplus solar energy at very low prices, the memo said.

CAISO will rely heavily on battery storage facilities to meet peak demand this summer, state energy officials *said* in May. A surplus of at least 5,500 MW is projected to be available to California during peak demand under normal conditions and 1,368 MW under extreme conditions, the officials said. ■

WRA Data Center Report Proposes Mandatory Clean Transition Tariffs

By Elaine Goodman

With data centers contributing to "staggering load growth" for Western utilities, a new report suggests that more utilities adopt clean transition tariffs for data centers or even make the tariffs mandatory for certain large customers.

The proposal is one in a set of recommendations from Western Resource Advocates, which released its *report*, "Data Center Impacts in the West," on July 22.

The report examines seven of the eight largest utilities in the Interior West: Public Service Company of Colorado, Public Service Company of New Mexico, NV Energy, PacifiCorp, Arizona Public Service, Salt River Project and Tucson Electric Power. These utilities are seeing a surge in large-load interconnection requests, and data centers are the largest factor in their load growth, the report says.

"Data centers are driving staggering increases in electricity demand," WRA says in its report.

And the surge in demand is a threat to climate progress, unless it can be met with clean energy resources, according to WRA. That's where clean transition tariffs can play a role.

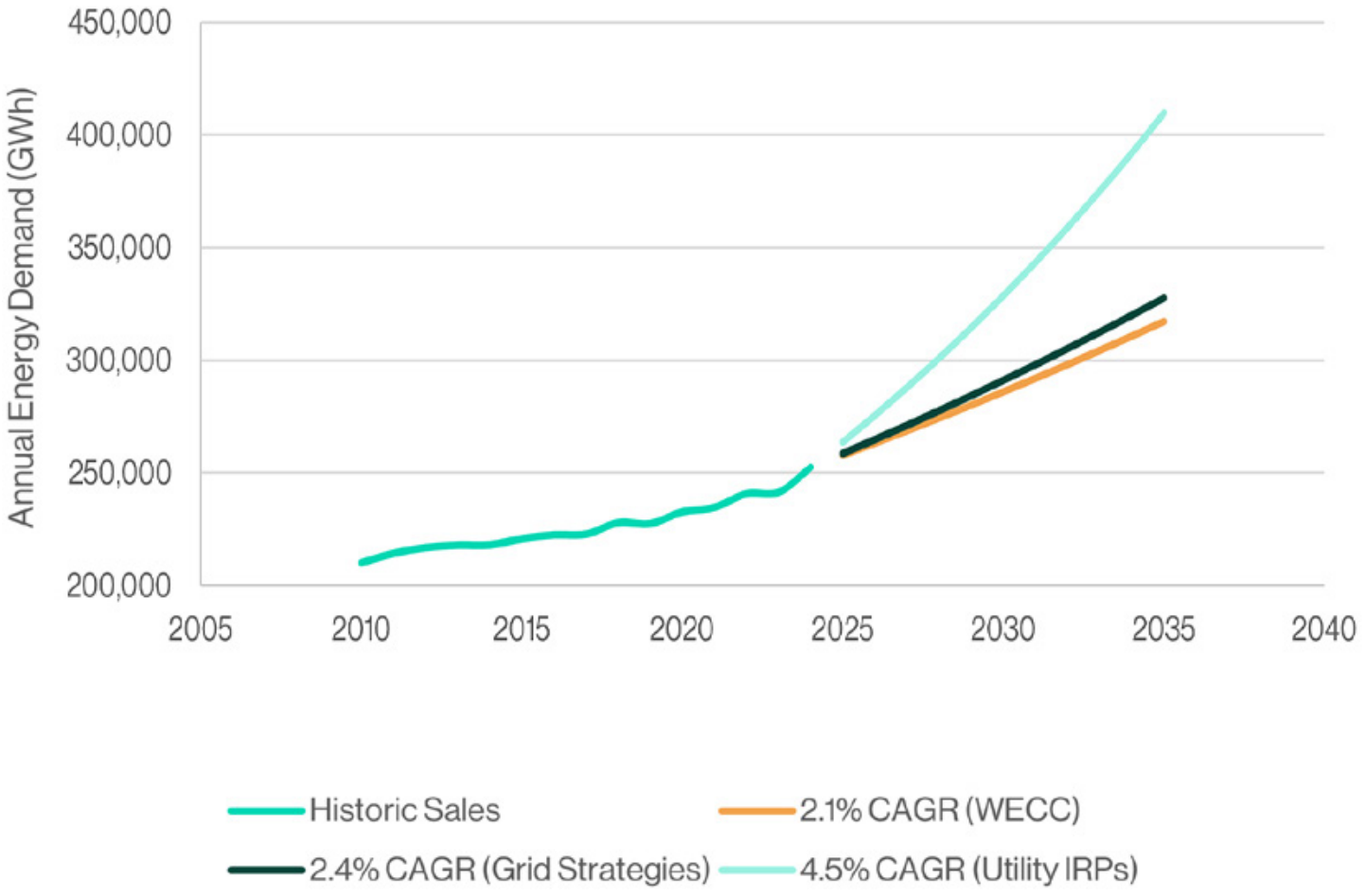
"If properly designed, these tariffs can enable data centers to do more than just mitigate their climate impacts with conventional clean resources like solar, wind and battery storage; they can help drive innovation by scaling new clean technologies," the report says.

Why This Matters

Explosive load growth from data centers threatens utilities' emission-reduction targets.

The report notes that companies such as Google, Meta and Amazon have corporate climate and clean energy goals — along with "expansive financial resources." Under a clean transition tariff, a utility may develop new, clean resources on behalf of a large-load customer, with the large customer paying any premium cost of the clean resource.

For example, Nevada regulators in March



Load-growth projections from seven major utilities in Arizona, Colorado, Nevada, New Mexico and Utah are higher than regional projections from WECC and Grid Strategies, according to a new study examining data center impacts. | *WRA*

approved NV Energy's clean transition tariff, a framework developed in partnership with Google. NV Energy added to its integrated resource plan an enhanced geothermal energy project from Fervo Energy that will help power Google's northern Nevada data center. Without Google's involvement, the utility would not have included the project because of its cost. (See *Nevada Regulators Give Nod to NV Energy Clean Transition Tariff*.)

WRA said clean transition tariff structures should be developed before a data center asks for interconnection and clean resources, because fast interconnection is typically a priority for the centers.

Only zero-carbon resources should be eligible for the tariff, the report says. One approach for finding resources would be for the utility to issue a request for proposals based on its completed IRP, select resources to serve customer loads and then make any resources not selected available to customers under its tariff. Utilities could also solicit bids for resources under their tariffs between IRP cycles.

Regulators should encourage utilities to develop clean transition tariffs, WRA says, and they could even consider making them mandatory for larger loads or those that are steady around the clock.

Surging Demand

The seven utilities' energy demands are projected to be 32% higher in 2030 and 55% higher in 2035, compared to 2025 levels, representing a compound annual growth rate of 4.5%. Those figures are significantly higher than what utilities predicted just a few years ago.

The growth rate is also higher than the rates projected by WECC (2.1%) and Grid Strategies (2.4%), which looked at regional and national trends, respectively.

The difference among the forecasts could mean that utilities in the WRA study are overestimating their load growth, the report says, or that they are "burgeoning hubs" for data centers with concentrated load growth.

As for peak demand, the utilities now expect a peak of 9,500 MW in 2030, 19% higher than in 2025, and 16,900 MW in 2035. The projected compound annual growth in peak demand is 2.9%.

The WRA report makes other recommendations for utilities and regulators, including:

- establishing best practices and requirements for utility load forecasting;
- revising IRP processes to better accommodate the rapid and uncertain nature of data center growth;
- allowing data centers to install behind-the-meter clean resources and storage systems; and
- developing interconnection standards that allow for load interruption in exchange for faster interconnection. ■

ERCOT Adds Industry Vet to Board of Directors

ERCOT said July 28 that its Board Selection Committee has tabbed industry veteran Bill Mohl to fill one of three independent director vacancies.

Mohl has 40 years of energy industry and risk management experience in electric and gas utilities, commodity trading, merchant generation, wholesale markets, electric power service companies and gas processing operations in public and private companies. He *retired after 15 years* with Entergy in 2017, having helped wind down the company's ownership of merchant nuclear plants.

Mohl also has spent time at Xcel Energy's Public Service Company of Colorado.

He currently is executive chairman of Shermco Industries, an electrical testing organization, and president of WMM Enterprises.

He holds a master's degree in business administration and a bachelor's degree in science from Regis University in Denver. Mohl also completed a nuclear operations board of directors course from Goizueta Director's Institute at Emory University.

"As the electric grid evolves to meet rapid growth and change, Bill's extensive expertise and leadership in the energy sector will support ERCOT's commitment to delivering industry-leading grid reliability and fostering efficient market operations," Board Chair Bill Flores said in a *statement*.

Bill Mohl | *Analysis Group*

ERCOT Board Chair Bill Flores welcomes a new board member. | © *RTO Insider*

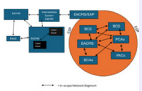
Two independent director vacancies remain after the recent resignations of Alex Hernandez and Sig Cornelius to pursue "new opportunities" in the ERCOT market. (See "Board Loses 2 More Directors," *ERCOT Board of Directors Briefs: June 23-24, 2025*.)

The *12-person board*, with eight independent directors, governs ERCOT and is subject to oversight by the Public Utility Commission and the Texas Legislature. By law, all board members must be Texas residents.

The board's selection committee was created by state law in 2021. It is composed of three members appointed by the governor, lieutenant governor or the speaker of the Texas House of Representatives. ■

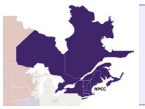
— Tom Kleckner

National/Federal news from our other channels



NERC Requests Clarity on FERC's INSM Order — ERO Insider

FERC Approves IBR Ride-through Standards — ERO Insider



FERC Accepts Amended NPCC Bylaws — ERO Insider

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

IESO Sees Improved 'Trust' Ratings in Survey

Stakeholders' Priorities Shifting

By Rich Heidorn Jr.

IESO is gaining ground in its "trust" ratings, ISO officials say.

The ISO's 2024 stakeholder and community engagement survey saw "across the board improvement" over 2023, Marko Cirovic, director of sector engagement, told the Strategic Advisory Committee at its July 16 *meeting*.

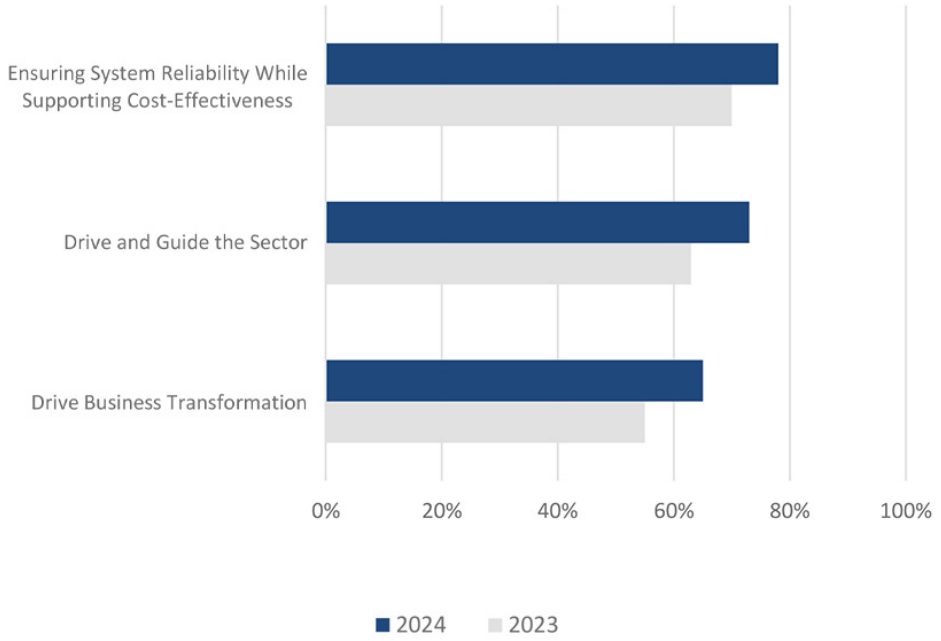
"Every key metric in the survey improved versus the previous year," Cirovic said. "Notably, 82% of stakeholders and communities said that our engagements met or exceeded expectations. This is a 6% increase from last year. This is not only the highest score in six years, but it is also the largest year-over-year gain since we started tracking this measure. And this really tells me one thing: Our efforts to listen, to learn and to collaborate are resonating across the sector."

IESO solicited responses from individuals who participated in engagements and conferences such as the First Nations Energy Symposium, along with those who worked on initiatives such as procurements and system planning. Respondents included distribution and transmission companies, generators and storage facilities, large consumers, municipal officials and Indigenous communities.

IESO described the results in a *memo* and *appendix* but declined *RTO Insider*'s request to release the full survey results.

The only negative cited in the ISO's presentation of survey results: "Confidence in the IESO slightly decreased this year, with about one-quarter (26%) of respondents indicating that they would speak highly of the organization in comparison to one-third (34%) in 2023."

The ISO noted that the 2024 question was updated from six answer options to four.



Percent of respondents giving positive scores (6 through 10) to the question: "How much do you trust the IESO to do each of the following?" | *IESO*

Why This Matters

ISO officials said the results are evidence that their efforts to be responsive 'are resonating.'

10-Point Scale

Some questions, including those measuring the trust respondents have in the ISO's ability to deliver on its three core strategies, used a 10-point rating scale, with 1 being very negative and 10 being most positive.

Asked "how much do you trust the IESO" to "drive and guide the sector," 73% ranked the ISO between 6 and 10, up 10 percentage points from 2023.

The ISO also reported gains in trust for "ensuring system reliability while supporting cost-effectiveness," with 78% giving "top 5" ratings, up from 70%, and 65% giving top 5 ratings for trust in the ISO's ability to "drive business transformation," up from 55% in 2023.

Shifting Priorities

Cirovic said the survey also indicated a shift in respondents' priorities.

"In 2023, sustainability was top of mind. In 2024, the focus has moved to future planning [cited by 51% of respondents], to affordability [also cited by 51% of respondents] and to reliability [cited by 46%]," Cirovic said. "This signals a growing emphasis on long-term resilience and growth."

Sustainability/clean energy ranked as the third most pressing issue in 2023, following planning/design for the future and cost/price/affordability, respectively.

Factors Influencing Trust

The ISO said the five factors with the greatest influence on respondents' trust in the IESO are: (1) transparency/information sharing; (2) long-term planning; (3) a track record of performance delivering reliable, affordable, sustainable electricity; (4) knowledgeable staff; and (5) communication and listening.

"There was also a positive correlation between the number of interactions with the IESO and respondents' trust in the organization," Cirovic said.

Almost nine in 10 respondents (89%) engaged with the IESO over the past year: 39% had between five and 25 interactions; 36% engaged fewer than five times; and 14% more than 25 times.

What's Next?

The 2025 engagement survey will open in August. Respondents can opt in at *engagement@ieso.ca*. ■

IESO Seeks to Fill Growing Regulation Needs

By Rich Heidorn Jr.

IESO will seek to fill its growing need for regulation services through competitive bids but will resort to bilateral procurements if there is insufficient interest, officials told stakeholders July 24.

IESO's most recent *Annual Planning Outlook* found the ISO will need 30 MW of additional regulation as soon as next year — with needs growing to 100 MW by 2029 — as a result of expected increases in industrial loads such as electric arc furnaces.

Regulation is one of several capabilities IESO uses to keep its supply and demand in balance, including inertial response, the stored kinetic energy of rotating equipment tapped immediately following a system event; primary frequency response, the automatic adjustment of energy output by generators within seconds of an event; and operating reserves, which the ISO calls on within 10 minutes or 30 minutes of an event.

Regulation resources respond to IESO instructions within five minutes of an event, after primary frequency response and before operating reserves.

Requirements

Generators providing regulation must be dispatchable, able to follow automatic generation control signals every two seconds or less and have an energy ramp rate of at least 50% of the offered regulation capacity per minute. A resource offering 20 MW of regulation, for example, would be required to move at least 10 MW/minute to reach its setpoint. IESO proposes a minimum regulation capacity of ±10 MW.

The ISO is seeking regulation only from facilities located south of Hanmer because severe weather in the Northwest zone and transmission congestion in the Northeast can restrict generation.

Storage currently is not eligible to provide regulation, but the capability will be added in future market rules under IESO's Enabling Resources Program, the ISO said. (See *IESO Seeks Feedback on Revised Storage Model*.)

In addition, IESO's dispatch scheduling software is unable to simultaneously schedule operating reserve (OR) from a resource providing regulation. As a result, resources providing regulation will receive real-time OR lost opportunity costs to make them whole for the OR revenue they would have received.

Because regulation is a reliability service, IESO does not need a government directive to procure it. The ISO could enter bilateral negotiations with facilities meeting technical requirements, or seek competitive bids, said Natalia Perdomo, an adviser in IESO's market and system adequacy team.

"The ISO's preference is a competitive procurement, as we believe it can provide better value for the ratepayer," she said. "However, if there isn't enough interest, the ISO can engage in bilateral negotiations."

Why This Matters

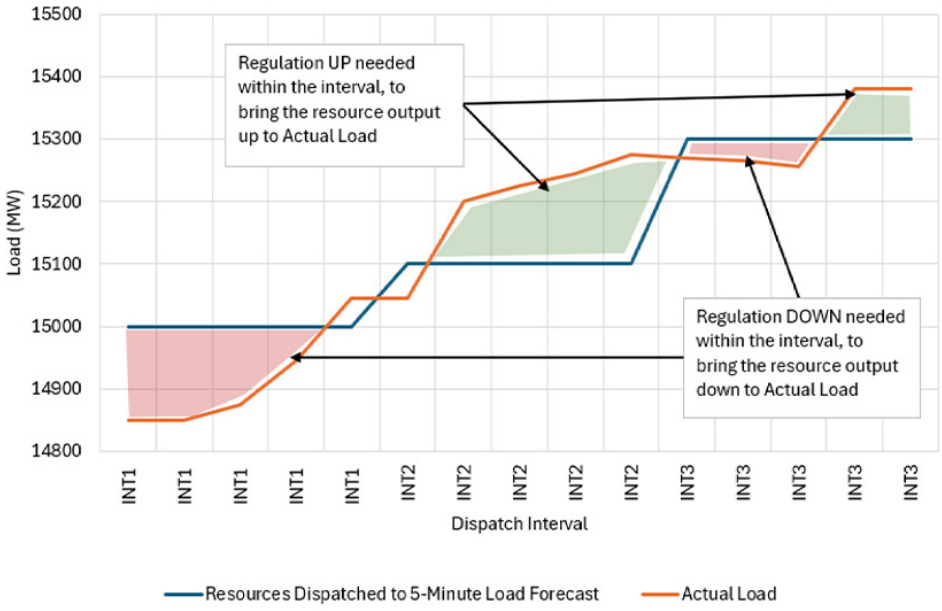
IESO will need 30 MW of additional regulation as soon as next year — with needs growing to 100 MW by 2029 — as a result of expected increases in industrial loads such as electric arc furnaces.

Next Steps

The ISO asked for written feedback by Aug. 8 via *engagement@ieso.ca*. It expects to decide on its procurement mechanism in the fourth quarter.

"If we do an RFP, the hope is that it would commence in 2026," IESO's Dina Shoukri said in response to a question about the timing and duration of the procurement.

"[The] duration of the contract, that is something we would have to determine," she added. "A lot of the answers to those questions are going to be informed by the feedback we get. So, once we understand availability, readiness to deliver, how much is out there, it will help to inform the answers to those questions." ■



Regulation resources respond to IESO instructions within five minutes of an event, after primary frequency response and before operating reserves. | *IESO*

The ISO is only seeking regulation from facilities located south of Hanmer because severe weather in the Northwest zone and transmission congestion in the Northeast can restrict generation. | *IESO*

IESO Seeks Feedback on Revised Storage Model

Goal: Single Bi-directional Model for Withdrawal and Injection

By Rich Heidorn Jr.

IESO opened stakeholder discussions on new rules for storage facilities and hybrid resources that will introduce a single bi-directional resource model and enable the provision of regulation service.

The *initiative*, part of the ISO's *Enabling Resources Program* (ERP), initially will focus on electricity storage and hybrid generation-storage resources, with a later "stream" to develop rules for aggregations of distributed energy resources (DERs).

"It's an important step for preparing Ontario for the required resources needed to meet the system needs that have been identified through the ISO's [*Annual Planning Outlook*]," David Short, senior director for the ERP, said during a kickoff *presentation* July 24. "More and more storage resources [are] being installed and operating, and at a scale that really requires us to develop the design of a good participation model to fully allow them to participate in meeting those system needs."

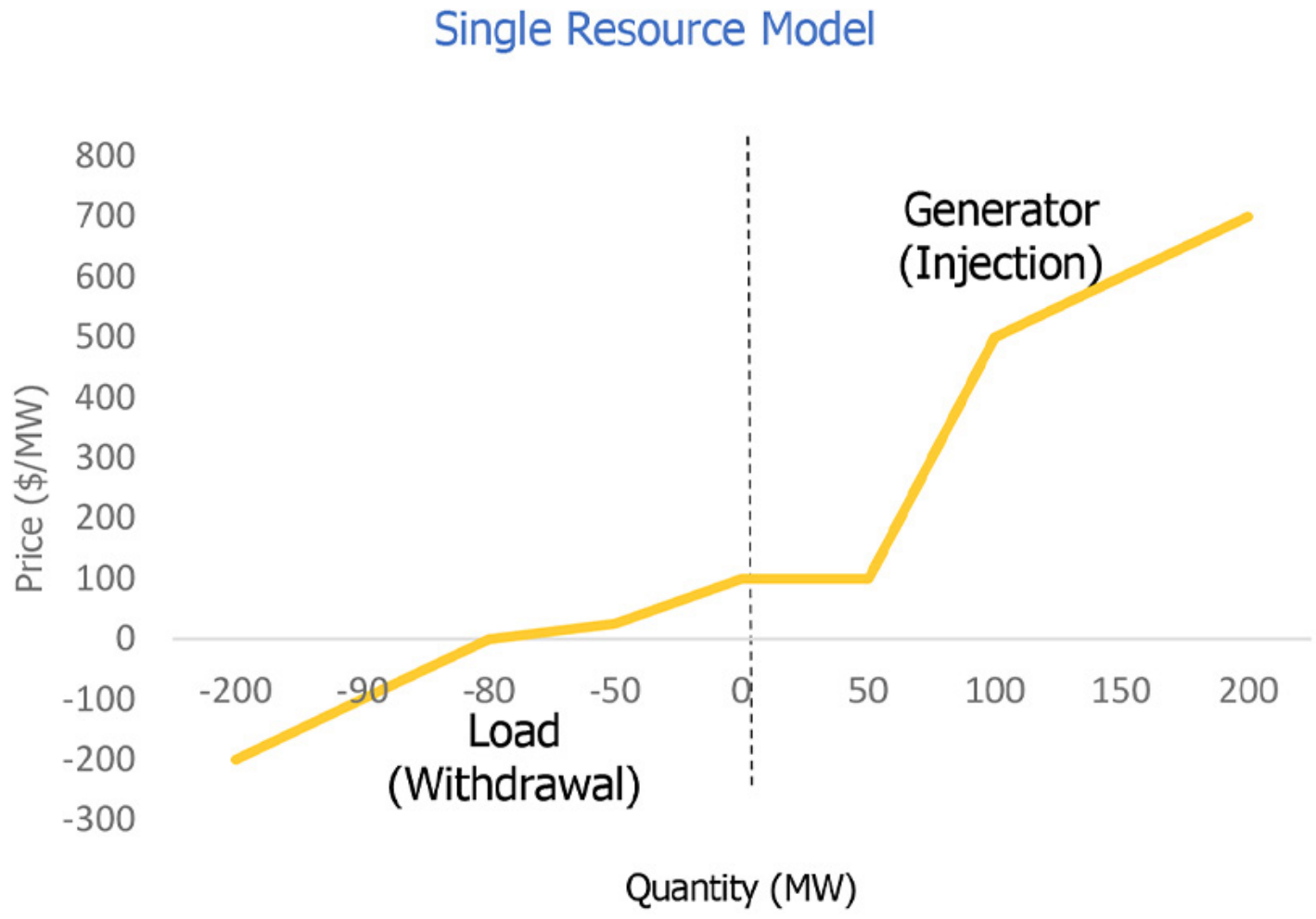
Why This Matters

Storage is becoming increasingly important for energy markets and reliability.

"We are hot off the heels of *Market Renewal*, and ERP is the next high-priority capital project for the ISO," said Maral Kassabian, senior manager of ERP implementation. "Its objective is to more fully enable resources to participate in the ISO markets, to enhance market efficiency and support the safe and reliable operation of Ontario's bulk power system."

The "Phase 1" rules, which IESO hopes to have in place as soon as 2027, will build on the interim storage model from 2018 and the co-located model implemented in 2023.

It will replace the current two-resource model — which separates the withdrawal portion of the resource as a load and the injection portion as a generator — with



IESO plans to replace its two-resource storage model — which separates the withdrawal portion of the battery as a load and the injection portion as a generator — with a single resource model with a continuous offer curve. | *IESO*

a single resource model with a continuous offer curve. When withdrawing, the resource will operate as a "negative generator," and when injecting, it will be a "positive generator," as in other jurisdictions, IESO said.

The new rules will apply to single-site, dispatchable battery storage greater than 1 MW that is connected to transmission or distribution. Other types of storage technologies will be considered in a subsequent phase.

Included in the proposal is a new parameter, the initial state of charge (SoC), measured in MWh, that market participants will submit for the day-ahead market.

The new rules will apply to the recent Long-Term 1 (LT1) and Expedited Long-Term (ELT) storage procurements, as well as Northland Power's 250 MW/1,000 MWh *Oneida* Energy Storage. (See *IESO Purchasing 3,000 MW of Energy and Capacity*.) Oneida began operating in May, *more than doubling* Ontario's energy storage capacity.

Storage facilities with existing contracts with IESO will continue participating as they currently do in the markets until their contracts expire.

Storage as Operating Reserves

The rules will seek to co-optimize storage's provision of both energy and operating reserves (OR).

The ISO is considering allowing storage to contribute to OR by injecting energy, stopping its withdrawals from the grid or "branching" from withdrawal to injection. (See *Operating Reserve Prices Surge in Ontario*.)

The new rules would allow storage resources to submit up to five price-quantity pairs hourly for each class of operating reserve (10-minute synchronized reserve, 10-minute non-synchronized reserve and 30-minute non-synchronized reserve).

Under current rules, a resource that offered a maximum price-quantity injection of 200 MW and a maximum withdrawal of -200 MW would not be able to offer more than the 200 MW as OR. Under the proposed branching rules, the resource could provide a maximum of 400 MW.

IESO is proposing a 100 MW/minute static energy ramp rate to "leverage the fast-ramping capability of storage upon dispatch but also limit operational concerns from extreme ramping on system balancing."

Cycling Daily Energy Limit

The ISO is considering a new parameter, the cycling daily energy limit (CycleDEL), for use in both day-ahead and pre-dispatch calculations. It will be based on the current MaxDEL, the maximum amount of energy a storage resource can inject daily.

CycleDEL will be the number of daily cycles submitted by the market participant at registration multiplied by the operating range of the battery (the difference between the maximum SoC and minimum SoC).

Storage operators would be allowed to increase the limits they offer at registration but not reduce them.

"I do like the idea of having a registered value and then the ability to change it during … real time," said Noralyn Vasquez, of Atura Power.

She noted that batteries' warranties have limits on cycling. "In addition, the more you cycle the facility, it does degrade the *Megapacks*," she added.

"Having these limits in the day-ahead [market] allows us to mitigate any buy-back risk if we're getting scheduled more often in the DAM relative to what we really can do in the real time," she added. "So, it's a good feature."

Feedback Sought

The ISO requested feedback by Aug. 21 on a range of topics, including telemetry requirements and derates of resources.

IESO plans a second meeting on the storage rules in October with a design memo on optimization in the fourth quarter. ■

ISO-NE Analysis Details Benefits of Demand Flexibility

By Jon Lamson

Increased demand flexibility could significantly reduce production costs, capital costs and transmission costs in New England by better aligning load with generation and reducing peak loads, ISO-NE said at the Planning Advisory Committee's meeting July 23.

Presenting additional results from its 2024 Economic Study, ISO-NE said demand flexibility could reduce production costs by 10 to 15% in 2050. The RTO found that capital cost savings would "increase linearly with increasing demand-side flexibility" by reducing reliance on "expensive resources that are only needed for short durations."

Demand flexibility would also provide emissions benefits by reducing load during the most carbon-intensive peak periods and would reduce the need for energy storage by limiting the imbalances between energy production and demand, ISO-NE found.

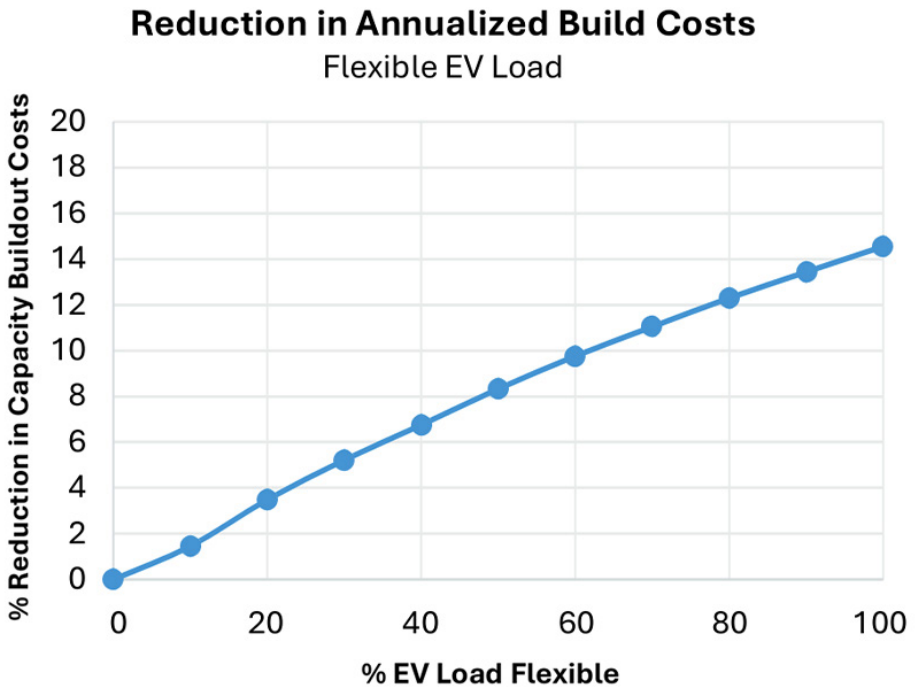
As a caveat to its findings, the RTO noted that the demand flexibility modeling assumes "perfect foresight and total control over flexible load" and therefore may inflate savings projections.

The study is intended to quantify the economic and environmental effects of state and federal energy policies and "evaluate competitive solutions to alleviate identified system efficiency needs." (See "2024 Economic Study," *ISO-NE Details Evaluation Models for Transmission Solicitation*; "Additional Economic Study Results," *ISO-NE Planning Advisory Committee Briefs: March 19, 2025*; and *ISO-NE Finds Advanced PV Panels Could Reduce Decarbonization Costs*.)

ISO-NE has previously forecast significant transmission savings associated with demand flexibility; it estimated in 2023 that the region could save up to $9 billion in transmission costs by reducing its forecast 57-GW peak load for 2050 to 51 GW. (See *ISO-NE Prices Transmission Upgrades Needed by 2050: up to $26B*.)

Also at the PAC meeting, ISO-NE discussed a sensitivity analysis from the Economic Study reducing the capital cost assumptions for small modular nuclear reactors (SMRs). The RTO's baseline assumptions for the study relied on conservative SMR *cost projections* from the National Renewable Energy Laboratory.

"The lower cost assumptions for SMRs shifted [their] buildout from 2039 to the mid-2030s and reduced the buildout of other non-emitting resources," said Kim Quach of ISO-NE. She noted that lower SMR costs also lowered reliance on peaker generation and largely eliminated the need for 100-hour battery storage.



Capacity buildout cost savings associated with electric vehicle demand flexibility | *ISO-NE*

Why This Matters

Demand flexibility has been a major focus of New England states in recent years and will likely be a key strategy for minimizing costs in the energy transition.

The RTO also discussed a model sensitivity reducing the emission-reduction requirements. It found that requiring only 75% decarbonization by 2050 would cut total costs by about 50% relative to the base case. The lower costs stemmed from decreased reliance on the most expensive clean resources needed to achieve deep decarbonization, including SMRs.

While scaling back the long-term decarbonization of the power sector could significantly reduce electricity costs, it would make it extremely difficult for states to meet their climate targets and reach net-zero emissions by 2050. Rhode Island has set a *goal* of meeting 100% of its power demand with clean energy by 2030, while Massachusetts has *estimated* it will need to cut power sector emissions by 93% by 2050 relative to 1990 levels to reach its net-zero goal.

The Intergovernmental Panel on Climate Change (IPCC) *estimates* that global emissions must decline significantly in the coming years and reach net zero by 2050 to limit warming to 1.5 degrees Celsius. Passing this warming threshold will intensify extreme weather events and have widespread negative impacts on human health, food and water supplies, and economic growth, *according to the IPCC*.

Resource Outlook Study

ISO-NE anticipates minimal shortfall risks over the next decade, with the loss-of-load expectation falling below the one-in-10 reliability criteria for each year, ISO-NE's Donald Poulin said in presenting

Continued on page 30

Tax Credit Phaseout Threatens Projects, Jobs in New England

By Jon Lamson

The expedited phaseout of federal tax incentives for renewables threatens projects and jobs across the clean energy industry in New England and is likely to trigger a mad dash of developers and states pushing projects forward to meet the deadlines set by the *One Big Beautiful Bill Act* (OBBBA).

The law, which was signed by President Donald Trump on July 4, made a particular target of wind and solar resources and drew heavy criticism from climate and labor groups across the country. (See *U.S. Clean Energy Sector Faces Cuts and Limitations*.) It and its associated executive actions already appear to have triggered job losses in New England and threaten to cause the stagnation or contraction of the region's growing clean energy industry and workforce.

"We are going to see, in all likelihood, projects stranded," said Harry Godfrey, managing director at Advanced Energy United. "It's bad for workers; it's bad for consumers; it's bad for American competitiveness."

For clean energy developers, the OBBBA contains two key aspects. First, it significantly accelerates the phaseout of the investment and production tax credits (ITC and PTC) for wind and solar projects. To be eligible for the credits under the new rules, projects must begin construction by July 5, 2026, or, if they miss the construction deadline, must be placed in service by the end of 2027.

The law also requires strict foreign entity of concern (FEOC) restrictions, intended to prevent credits from going to companies owned or controlled by entities tied to China, North Korea, Iran or Russia, or to companies that source a certain portion of their equipment from these countries.

The projects likely to be most vulnerable to the phaseout, Godfrey said, are large-scale wind and solar projects that are two to three years away from beginning construction and could not feasibly expedite development to receive the tax credits.

For these projects, "the assumptions around the credits are baked into the project financing … and all of a sudden you have to go back and revise that," Godfrey said.

Why This Matters

New England states have bet heavily on renewables to meet expected load growth and face tough policy questions as tax credits for wind and solar resources expire.

Godfrey said the placed-in-service deadlines established in the law will create major investment risks for projects aiming to meet the deadlines because factors largely outside the control of the developer — such as permitting, interconnection or legal challenges — all could cause a project to miss a deadline.

"A placed-in-service deadline really becomes an effective project killer," he said.

Offshore Wind

In Massachusetts, the biggest effects of the Trump administration may be on the offshore wind industry.

Lawmakers and clean energy advocates in the state have long envisioned offshore wind as an essential resource for meeting growing power demand and decarbonizing the economy. ISO-NE has *emphasized* the importance of offshore wind to maintaining reliability and resource adequacy.

However, while Revolution Wind and Vineyard Wind are fully contracted, under construction and set to come online over the next two years barring unforeseen obstacles, the region's second wave of projects faces a highly uncertain future.

New England Wind 1 and SouthCoast Wind, which both received their final federal permitting approvals under the Biden administration and were selected in a 2024 multistate solicitation, have seen repeated delays to their contract negotiations because of federal policy uncertainty. (See *New England OSW Contracts Delayed Again*.)

"The OBBBA essentially shoots a 30% hole through the financing of solar and wind projects, and that's not possible to make up from state incentives," said Amy Boyd Rabin, vice president of policy at the Environmental League of Massachusetts. "It is a significant blow to renewable energy and significantly undoes a lot of the work that prior administrations had done to level the playing field with all the subsidies and incentives we give fossil fuels."

Offshore wind developers have indicated they are closely awaiting guidance from the Treasury Department on the start-of-construction rules and will need a significant degree of federal policy certainty to proceed with the second wave of projects in the region.

Elizabeth Mahony, commissioner of the Massachusetts Department of Energy Resources, said the "biggest challenge we're seeing at the federal landscape is the Day 1 executive orders on permitting," adding that "not having a clear picture on permitting is a significant challenge."

The Trump administration has not shied away from targeting fully permitted projects, as Trump's Day 1 order directed a review of existing wind energy leases. In April the administration halted construction on the fully permitted Empire Wind 1 project, which is under contract with New York. The administration ultimately lifted the halt in May, reportedly in exchange for concessions from New York regarding new gas infrastructure into the state. (See *BOEM Lifts Stop-work Order on Empire Wind*.)

Asked whether Massachusetts would consider a similar hypothetical deal to lift federal permitting barriers to offshore wind in exchange for state concessions around natural gas infrastructure, Mahony said the state is "focused on what we can control, and that's solar, storage and wind programs that we have actively going in Massachusetts."

"The governor has repeatedly said that we are an all-of-the-above-solution state," Mahony added.

Vineyard Wind

Offshore wind project cancellations or major delays will have a major impact on the state's clean energy workforce. The construction of Vineyard Wind has created about 1,000 union jobs, and the Massachusetts Clean Energy Center forecasted in 2023 that offshore wind would be the fastest growing subsector of the clean energy workforce by 2030.

"We see offshore wind as a really big opportunity," said Ryan Murphy, executive director of Climate Jobs Massachusetts, a labor union coalition group. "It would be a significant loss if those projects don't go forward during the Trump administration."

The administration already appears to have caused job losses in the region. In February, in the wake of Trump's executive order halting permitting approvals for offshore wind, the developer Vineyard Offshore cut 50 jobs.

"For the projects that we know are planned for Massachusetts that are either on hold or have been canceled, we estimate more than 5,000 construction jobs would not go forward if those projects don't go forward," Murphy said.

Along with immediate impacts on local communities, businesses and working families, "what that means is that unions — without commitments to jobs — are not able to train as many workers in the meantime to get them ready for future clean energy projects," Murphy said.

He added that while most of the skills taught by unions are transferable to a range of other infrastructure and energy projects, "the fact is, if you take away thousands of construction jobs, you don't necessarily have a one-to-one replacement or thousands of other construction jobs that those workers can go and do."

Solar Development

The looming expiration of the PTC and ITC also poses a major threat to the solar industry in New England.

The ITC, which was expanded and extended by the Biden administration, has been the "foundation of clean energy development in this country for 20 years," said Jessica Robertson, director of policy and business development in New England for New Leaf Energy.

Looking at New Leaf's project pipeline under existing conditions, projects that would be able to survive without the ITC are "very few and far between," said Robertson, who added that she is optimistic that the company took the necessary steps to meet start-of-construction deadlines for its projects prior to the passage of the OBBBA. That should help protect its project pipeline in the near term.

But project eligibility for tax credits will likely depend on the stringency of the guidance issued by the Treasury, and whether the administration seeks to apply the changes retroactively to investments that were made to safe harbor projects prior to the law's enactment.

In an executive order issued after signing the bill, Trump directed the treasury secretary to issue new guidance "to ensure that policies concerning the 'beginning of construction' are not circumvented, including by preventing the artificial acceleration or manipulation of eligibility and by restricting the use of broad safe harbors." (See *Trump Executive Order Targets Renewable Energy Tax Credits*.)

At the state level, Robertson expressed hope that recent policy changes, particularly in Massachusetts, will help reduce development costs associated with interconnection and permitting, and may even help some projects meet the tax credit expiration deadlines set by the law.

The Massachusetts legislature passed major siting and permitting reform legislation in late 2024, limiting the permitting approval timeline to 12 months for small clean energy projects and 15 months for large projects, and allowing developers to appeal local permit rejections to the

state Energy Facilities Siting Board. (See *Mass. Clean Energy Permitting, Gas Reform Bill Back on Track*.)

The state has also established a framework for covering the upfront costs of distribution-level interconnection upgrades in the rate base and has required more proactive planning in the utility Electric Sector Modernization Plans. (See *Mass. DPU Approves 1st Round of Utility Grid Modernization Plans*.)

Massachusetts also issued in June an emergency update to its Solar Massachusetts Renewable Target program, a key state policy for supporting solar development. The changes are intended to allow the program to reflect annual changes in the cost of building solar and help the state respond to changing federal policy.

But states can only do so much to fill the gaps left by the loss of federal tax credits. New Leaf announced in July the layoff of about a fifth of its workforce, citing the need to "reduce its cost structure in preparation for a market without the federal ITC."

Robertson said the company's utility-scale projects that cannot meet the in-service deadlines will be most affected by the tax credit changes and said New Leaf is "still exploring our options for those projects."

Storage Development

While the OBBBA made relatively minor changes to the ITC deadlines for energy storage, development will likely face significant impacts from the FEOC changes.

"There's significant opportunity for folks to focus on storage, or pair their projects with storage, to retain some of the ITC for that portion of the project," said Sean Burke, director of policy at BlueWave Energy. "However, the foreign entity of concern provisions in the One Big Beautiful Bill are complex and novel for the industry to deal with, and I think it's going to take some time for us to all figure out how those work."

Compared to wind and solar, Burke said storage developers are required to source a higher percentage of their components from non-FEOC suppliers, with this percentage set to increase over time.

These requirements will depend in part on how the Treasury implements the bill's FEOC restrictions. Trump's July 7 executive order directed the department to act on the FEOC restrictions within 45 days of the law's enactment.

Ultimately, the ITC remains "vitally important" for storage development, Burke said, adding that the "biggest challenge at this point" for storage developers is uncertainty around FEOC guidance, and "whether that will make it more challenging for projects to meet those requirements than was envisioned in the legislation."

Storage development has been a major focus in New England in recent years, and the Massachusetts legislature in 2024 directed the procurement of 5,000 MW of storage by mid-2030, which must include significant amounts of long-duration storage. (See *Mass. Clean Energy Permitting, Gas Reform Bill Back on Track*.)

Burke said states procuring storage "need to be aware of the changing landscape around foreign entity of concern" and must be diligent about supplier claims of compliance with FEOC guidelines "because the rules are so complex that claims may not bear out in reality, and that would impact the viability of the bid." ■

ISO-NE Analysis Details Benefits of Demand Flexibility

Continued from page 27

the RTO's 10-year resource outlook study.

He noted that forecasted shortfall risks increase as the decade progresses because of growing load and the assumption of a stagnant resource mix.

Asset-condition Projects

Chris Soderman of Eversource Energy *presented* a $24 million asset-condition project to replace 48 wood structures with steel structures on a 115-kV line in southern New Hampshire.

The company has identified damage and deterioration on 25 structures and will replace additional "Category B" structures facing flooding, uplift issues or are in "close proximity" with more deteriorated structures, Soderman said.

Under the transmission owners' standardized PAC presentation guidelines, Category B refers to structures with moderate deterioration that may be replaced "in conjunction with other structure replacements."

Soderman also *presented* a $6 million project in New Hampshire to replace 15 wood structures on a separate 115-kV line. He said six of the structures have deteriorated to the point of needing replacement, while nine structures are categorized as Category B proximity structures.

Connecticut Needs Study

ISO-NE also discussed a *revision* to its Connecticut 2034 Needs Assessment.

Following an update to correct errors in the load distribution in Rhode Island, ISO-NE has reduced the extent of thermal overloads it forecasts for Connecticut in 2028 and 2034, along with the number of buses with low-voltage violations it forecasts for 2028.

The revisions did not affect the number of high-voltage violations identified by the RTO, which are associated with minimum loads.

The RTO plans to publish the draft assessment "in the near future" and aims to release the final version in August. It intends to begin work on the Connecticut 2034 Solutions Study in the third quarter of this year, focusing on short-term needs. ■

FERC Approves MISO Interconnection Queue Fast Lane

Approval Comes Just 2 Months After Rejection of Earlier Iteration of Plan

By Robert Mullin

FERC on July 21 approved a controversial MISO proposal to create a fast lane for certain reliability-related projects in the RTO's interconnection queue — just two months after rebuffing an earlier version of the plan (*ER25-2454*).

The commission in May rejected the first iteration of the Expedited Resource Addition Study (ERAS) proposal, which was designed to speed up interconnection of resources that state regulators have identified as necessary to ensure resource adequacy in areas under their oversight.

In its May decision, the commission found the original ERAS plan lacked clarity around standards for identifying true RA projects and that — absent a cap on potential applicants — the expedited process was at risk of becoming bogged down with too many proposed projects. (See *FERC Rejects MISO's Interconnection Queue Fast Lane*.)

Responding to those concerns, MISO quickly developed a revised proposal that caps the ERAS fast lane at 68 project requests and includes a provision requiring the RTO's relevant electric retail regulatory authorities (RERRAs) to verify in writing that a project will either address an RA risk or help load-serving entities meet previously unexpected load growth.

Of the 68 slots, MISO proposed that a maximum of 10 would be carved out to accommodate requests from independent power producers that have agreements with entities other than LSEs, while eight will be dedicated to requests for resources intended to serve retail-choice load.

The RTO also proposed to cap the number of expedited studies to just 10 per quarter and limit transmission service requests to 150% of the need identified by a RERRA. It also made clear the ERAS process would be a temporary fixture, concluding at the earlier of either August 2027 or when the queue is cleared.

While MISO's rapid turnaround on the revision earned support from the RTO's vertically integrated utilities, it provoked protests from independent power producers and clean energy groups, who argued the newer plan still retained "many of the shortcomings" of the earlier version while introducing additional legal concerns. They also argued it still offered "preferential access to thermal resources at the expense of renewable resources." (See *MISO's Queue Fast Lane, Take 2, Nets Déjà vu Arguments*.)

Invenergy was among the independent power producers that protested MISO's revised ERAS plan. | *Invenergy*

Why This Matters

FERC approval of MISO's interconnection fast lane means certain reliability-driven projects will get to jump the RTO's long queue.

Michigan's Public Service Commission also opposed the plan, arguing it lacked "sufficient enforcement of shovel readiness and project completion" and that a provision to cap the megawatt value of expedited projects at 150% of an identified RA need might exclude meaningful participation by developers of renewable energy projects, which have lower capacity factors than thermal projects.

In its comments to FERC, Invenergy argued the new proposal still vested RERRAs with "nearly unbounded discretion to select projects, without any objective criteria to judge whether such projects are capable of satisfying MISO's resource adequacy needs."

But the revised plan had strong backing among MISO's utilities, among them Alliant Energy, Ameren, Big Rivers Electric, Consumers Energy, DTE Energy, Northern Indiana Public Service Co. and Ottertail Power.

'One-time Design' Weighs Heavily

FERC's July 21 order found the eligibility requirements set out in the revised proposal were adequate to "deter speculative interconnection requests from entering the ERAS process and minimize disruption" to resources already sitting in the definitive planning phase of MISO's existing interconnection process.

"We find that MISO's revised ERAS proposal sufficiently addresses these concerns identified in the May 2025 order by capping the number and size of ERAS

projects, strengthening the RERRA verification requirement, [and] requiring ERAS interconnection requests to be located in the same local resource zone as the resource adequacy or reliability need that it will address," the commission wrote.

"Additionally, we note that the limited, one-time design of the process weighed significantly on our decision here," it added.

The commission also found that MISO had "strengthened" the "notification" requirement in the initial ERAS plan "to better ensure that RERRAs affirmatively verify interconnection requests will address specific resource adequacy needs that are not otherwise being addressed."

The commission said it was "reasonable and appropriate" for MISO to allow RERRAs to select the ERAS projects and "implement their own processes for making such determinations, as this approach strikes a reasonable balance between state authority over resource procurement and commission authority over generation interconnecting to the interstate transmission system. Accordingly, we find that it is not necessary for MISO to establish scoring criteria or a ranking process for proposed ERAS projects, as protesters suggest."

The commission rejected the argument by IPPs that the proposal intrudes on the commission's exclusive Federal Power Act jurisdiction over the transmission service terms and conditions set out in MISO's tariff.

To support their argument, the IPPs cited the U.S. Supreme Court's *Hughes v. Talen Energy Marketing* decision, which held that the Maryland Public Service Commission's authority over generating facilities did not allow it to "exercise control over the terms and conditions of interconnection service."

"We find that the revised ERAS proposal is permissible under *Talen* because RERRA participation in the ERAS process would be wholly pursuant to a commission-jurisdictional process (i.e., the generator interconnection process), proposed by MISO and approved by the commission — not by state authorities — and under which a [generator interconnection procedure] is on file with the commission and any future revisions would be subject to commission approval," FERC wrote.

The commission also rejected the contention that the proposal violates the "filed rate" doctrine because it allows states — through their RERRAs — to set the criteria for determining a resource's participation in ERAS without subjecting that criteria to FERC approval.

"NextEra and MISO IPPs argue that the revised ERAS proposal violates the filed-rate doctrine because it allows RERRAs to establish criteria that would not be on file with the commission and that would determine whether or not an interconnection request is eligible for ERAS. We disagree. We find that the revised ERAS proposal does not present a filed-rate doctrine concern because it provides adequate notice of the ERAS eligibility requirements, including the RERRA verification requirement," the commission wrote.

MISO intends to kick off the first ERAS process on Sept. 2. ■

DOE Pulls $4.9B in Funding for Grain Belt Express

By Tom Kleckner

The Department of Energy says it has terminated its $4.9 billion conditional loan commitment for the long-delayed Grain Belt Express project, saying it is "not critical" for the federal government to support the project.

"After a thorough review of the project's financials, DOE found that the conditions necessary to issue the guarantee are unlikely to be met," the DOE said in a July 23 *press release*.

DOE said the Loan Programs Office's loan guarantee, issued by the Biden administration in November 2024, was one of many conditional commitments "rushed out the door" shortly after the 2024 election.

A project spokesperson said the developers are disappointed with the withdrawn LPO loan guarantee, noting that the Grain Belt Express "will be America's largest power pipeline."

"A privately financed Grain Belt Express transmission superhighway will advance President Trump's agenda of American energy and technology dominance while delivering billions of dollars in energy cost savings, strengthening grid reliability and resiliency, and creating thousands of American jobs," the spokesperson said in an email to *RTO Insider*.

Rob Gramlich, Grid Strategies' president, said the decision was "confusing," given the administration's focus on the need for energy to power artificial intelligence data centers.

"We really need interregional transmission and [DOE] Secretary [Chris] Wright and now the White House, through their AI plan, say transmission is important," he told *RTO Insider*.

The DOE has pulled a $4.9 billion loan commitment from Invenergy's Grain Belt Express. | *Invenergy*

The DOE said it is conducting a review of every applicant and borrower, including the nearly $100 billion in closed loans and conditional commitments the LPO made between Election Day 2024 and Inauguration Day 2025.

DOE's action is the latest hurdle facing the Grain Belt Express, an 800-mile HVDC project that has been under development since 2010. The project's developer, Invenergy, says the $11 billion merchant transmission line would be capable of moving 5 GW of *mostly clean energy* from Kansas across Missouri and Indiana and into Illinois.

The news was *celebrated* by U.S. Sen. Josh Hawley (R-Mo.), who has called the project a "boondoggle" and twice sent letters to the DOE urging the agency to cancel the loan guarantee. Hawley took credit for the cancellation, charging that the project "has taken the land of numerous Missouri farmers across eight counties while padding [Invenergy's] corporate profits." (See *Grain Belt Funding Appears on Shaky Ground with DOE; Invenergy Firm on Value*.)

The project has been approved by regulators in all four states involved. The Missouri Public Service Commission found the project would save the state's customers as much as $18 billion, Invenergy has said. The company noted municipal utilities in 39 communities have contracts with it for power delivery and contractually guaranteed cost savings.

However, the project has faced opposition from Missouri landowners, who are opposed to a for-profit, private entity using eminent domain. Missouri Attorney General Andrew Bailey has criticized Grain Belt Express for filing nearly 50 eminent domain lawsuits against Missouri landowners. He opened a consumer protection investigation into the project in June. (See *Missouri AG Opens Inquiry into Grain Belt Express*.)

Bailey issued a *statement* saying his office has "won a battle in the war for Missouri landowners" in what he termed an "unconstitutional land grab."

"If Invenergy still intends to force this project on unwilling landowners, we will continue to fight every step of the way," he threatened.

The project's developers *filed a lawsuit* against Bailey July 16, arguing that he does not have the authority to investigate Grain Belt Express or to interfere with the Missouri PSC's final order.

Invenergy says the $11 billion project would provide $52 billion in energy cost savings over 15 years, create 5,500 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 the Grain Belt Express would move a "diverse mix of energy" from Kansas to Indiana. The project would save money 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.

Grain Belt Express 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*.)

Grain Belt Express announced nearly *$1.7 billion in combined contractor awards* to Quanta Services and Kiewit Energy Group. ■

Notable Quote

"If Invenergy still intends to force this project on unwilling landowners, we will continue to fight every step of the way."

— Missouri Attorney General Andrew Bailey

NYISO Cancels Offshore Transmission Studies

In the wake of the New York Public Service Commission's decision to cease planning its offshore wind underwater transmission network, NYISO has followed suit, tossing two years of planning studies. (See *NY Steps Back From OSW, Halts Offshore Tx Planning Process*.)

At the Transmission Planning Advisory Subcommittee's meeting July 23, NYISO's Jason Frasier thanked developers, ISO staff and stakeholders for their work and participation in the Public Policy Transmission Need process, initiated by the Department of Public Service in June 2023. NYISO revealed the bids in its solicitation in June 2024 and was targeting a selection by the Board of Directors in the second quarter of this year. (See *NYISO Reveals Bids in NYC Offshore Transmission Solicitation*.)

Frasier said that the ISO will now solicit feedback from stakeholders on the PPTN process for potential improvements.

Howard Fromer of Bayonne Energy Center asked whether developers would be reimbursed or compensated for their participation. Frasier said there was no mechanism in the tariff for developers to get compensated for a PPTN that was not finished.

Other stakeholders asked whether projects in the interconnection queue that were being built with the assumption of the PPTN would also be canceled automatically. Frasier indicated that those developers would need to withdraw or revise their projects. Absent a withdrawal notice, they would remain active.

Shutterstock

A representative from Earthjustice asked whether any of NYISO's studies of the benefits of offshore transmission would be retained or released. Frasier said that no benefit evaluation would be completed or released beyond what the ISO had already done. ■

— Vincent Gabrielle

N.Y. Considers New Fossil Generation as Renewables Lag

Draft Update of Energy Plan Acknowledges Difficulty Meeting Decarbonization Goals

By John Cropley

As it updates its energy plan to reflect new challenges to decarbonization, New York is contemplating what until recently seemed improbable, or even unthinkable: new fossil-fired generation.

The state Energy Planning Board voted July 23 to publish the draft 2025 update of the *state Energy Plan* after 10 months of deliberations. *A series of hearings* across the state is scheduled to gather input on the draft.

Further updates and revisions to the draft are expected as it approaches finalization toward the end of this year and the effects of federal policy changes become clear.

The board's chair — Doreen Harris, CEO of the New York State Energy Research and Development Authority — told *RTO Insider* that the huge shifts in federal policy over the last six months created uncertainty to a degree that required the board to present a range of scenarios in the draft. She said federal actions over just the past few weeks may have rendered some of those scenarios overly optimistic.

The Trump administration is actively moving to thwart energy efficiency and clean energy initiatives such as those New York has worked more than a decade to build. Meanwhile, the recently enacted reconciliation bill, the One Big Beautiful Bill Act, eliminates federal subsidies that states were counting on to incentivize renewables development and shifts billions in federal spending obligations to state governments, thus limiting whatever inclination states had to subsidize renewables on their own.

The fossil-fired Ravenswood Generating Station is the largest power plant in New York City. | *Shutterstock*

As such, New York is contemplating strategy shifts on multiple fronts with the draft update.

Ambition vs. Results

New York has had mixed results in expanding its renewables portfolio and shrinking its carbon footprint.

The Climate Leadership and Community Protection Act — New York's landmark *2019 climate law* — mandates 70% renewable energy and a 40% reduction in greenhouse gas emissions, as well as 100% zero-emission energy by 2040.

But officials have acknowledged the state is likely to miss the two 2030 goals, possibly by a wide margin: GHG emissions were down only 9.3% as of 2022, and renewables accounted for only 27% in 2023.

The draft update acknowledges the challenges facing the 2040 zero-emissions energy goal as well. Given the 23% increase in peak demand and 26% increase in annual demand expected by 2040, the draft emphasizes the importance of not falling further behind on generation capacity.

One scenario envisions current-day nuclear and hydro assets continuing to play a key role in the state grid in 2040, joined by 35 GW of solar; 9 GW each of storage, onshore wind and offshore wind; and 16 GW of green hydrogen combustion.

Any of those targets could be a challenge in the current environment, but hydrogen stands out as a leap of faith.

The draft immediately acknowledges the technical challenges of generating huge quantities of hydrogen in an ecologically and economically sound manner. And it acknowledges that hydrogen or other "clean firm" technologies critical to this planning process are not yet scalable.

So the draft looks at fossil fuel as indispensable for some time to come. Natural gas and petroleum will be diminished but still important energy resources in New York in 2040, the draft says, and fossil generation will remain essential to grid reliability.

Why This Matters

The state with one of the strongest commitments to renewable energy is acknowledging that renewables may not yield as much electricity as expected as soon as expected.

But a quarter of the state's combustion generation capacity will be at retirement age as soon as 2028, so the state will need to be strategic about the pace of combustion unit retirements, the draft warns, and will need to consider whether new or repowered fossil-fuel generation is necessary.

Harris said the state's energy planning process has been faced with moving variables since President Donald Trump began his second term, and she said some of the scenarios laid out in the draft plan are based on factors and assumptions that recently became outdated.

"If anything, the reconciliation bill may have rendered even that planning case a bit optimistic from the perspective of renewable deployment in particular," she said.

NYSERDA's senior vice president for policy, analysis and research, Carl Mas, said the language in the draft about new fossil generation is intentionally broad because there is such a broad range of possible outcomes as New York navigates state and federal economic and policy factors.

But there are scenarios under which the state — which had sought to phase out fossil fuel generation in the 2030s —would instead seek construction of new fossil generation or retrofits to make older facilities cleaner and more efficient.

"With the load growth that we're seeing,

we feel like we have to remain flexible," Mas said. "There's extreme amounts of uncertainty, but we have a very old fleet, and we have a growing load and substantial new headwinds that we didn't have five or six years ago."

This does not alter the state's commitment to renewables and decarbonization, Harris and Mas said. It recognizes that the plan for carrying out that commitment may need to be modified to maintain reliability.

Tough Decisions

New York has a number of hard choices to make with its energy portfolio, and the draft update of the plan lays out some of the potential decision-making pathways in a rapidly evolving landscape. But it will not make the decisions easier.

Renewables advocates have been unhappy about the state ratcheting back initiatives that have become untenable or expensive, and about the slow pace at which the New York Power Authority is starting its role as a renewables developer. Any move to authorize major new fossil infrastructure is likely to go over just as badly.

Meanwhile, New York must decide whether to continue to subsidize the nuclear power plants that supply 22% of the state's total electricity and 42% of its emissions-free electricity. Over the past seven fiscal years, this zero-emission credit program has consumed $3.73 billion gathered from surcharges on electric bills.

The draft plan highlights the importance of the ZEC program, but it also states bluntly that "it is not feasible to continue increasing the number and scale of programs that electric ratepayers need to fund."

Another challenge: New York's renewable energy pipeline — partly rebuilt after mass cancellations in 2023 — faces a new round of cancellations because of the impending end of federal tax credits under the reconciliation bill.

"We have literally seen the federal government's action result in tens of billions of dollars of impact on New Yorkers with respect to clean energy deployment costs," Harris said.

There is a wave of collateral damage beyond the tax credits, she said, as the industries and workforce that were growing in the clean energy sector retract and retreat.

Harris added, though, that renewable energy is not expected to halt; the question is how much it will slow.

"So this energy plan is taking into account the realities of having those tools impacted," Harris said.

Simultaneous Goals

The draft plan's summary alone stretches 80 pages and reminds the reader why governmental processes sometimes move so slowly: It is filled with parallel and secondary goals that rope in a massive cast of stakeholders and competing interests.

The draft suggests that as New York is reducing its carbon footprint and keeping its grid reliable, it should upgrade one of the oldest housing stocks in the U.S.; move to 100% zero-emission vehicle sales; reduce negative impacts on disadvantaged communities and actively steer positive impacts toward them; bolster organized labor; help poorer New Yorkers cut their energy costs; craft a more cohesive energy planning process; support research and development; build at least 1 GW of nuclear capacity; develop the energy workforce; lead the country in battery energy storage safety; maintain reliable gas transmission networks that can meet peak demand; consider wholesale electricity market reforms; and integrate renewables into the land-planning practices of often oppositional local governments.

And it wants to do all of this affordably.

"These are all goals that the state can meet without sacrificing one for another," the draft says.

It estimates that some of the scenarios would raise energy costs more than 35% by 2040. That is expected to be offset to some extent by lower health care costs and other societal benefits, but it would be a lot of money on top of already high rates. Heavy investment is needed under any scenario because of the age of existing transmission and generation infrastructure and the increased demands expected to be placed on them.

But any embrace of new or rebuilt natural gas-fired generation would be a bitter pill to swallow for clean energy advocates.

Marguerite Wells, executive director of the Alliance for Clean Energy New York, avoided the words "natural gas" in a statement but made the trade group's priority clear: "Electric demand is rising, and legacy generating sources are aging. It's patently obvious that renewable sources are going to be the fastest and lowest-cost method of bringing new power onto the grid."

ACE NY looks forward to commenting on the draft, she said, and working with the state to identify the inefficiencies and road blocks that are delaying renewables.

State policy not long ago favored natural gas as the preferred alternative to coal and oil.

The *2015 update* of the State Energy Plan discussed New York's ambitions for, and early steps with, renewables. But it also said, "Economic, operational and environmental advantages make natural gas the current fuel of choice for new and replacement generation in New York."

The 2019 climate law canceled that line of thought. But there was always going to be an off-ramp in case the vision did not come together as hoped.

In the *2022 Scoping Plan* it prepared for the law, the state Climate Action Council said, "The effectiveness of programs and policies should be continually evaluated and changed if renewable energy is not being deployed at the pace necessary to achieve the requirements on time."

The July 23 vote to publish the draft set in advance the process for such a potential change.

Jackie Bray, commissioner of the Division of Homeland Security and Emergency Services and a member of the Energy Planning Board, said she was glad alternate scenarios were included in the draft in case the preferred scenario becomes impossible.

There can be a tendency in this type of planning process, she said, for well-meaning leaders to continually add objectives to a blueprint on the assumption that there is time over the next decade to figure out how to reach those objectives.

"Make sure that we are being realistic about what we can deliver and what we must deliver," Bray urged listeners. ■

New York Issues 1st RFP for Energy Storage

By Vincent Gabrielle

New York Gov. Kathy Hochul *announced* the first of three *solicitations* for bulk energy storage July 28 as part of the state's goal of deploying 6 GW by 2030.

Each solicitation aims to procure 1 GW of energy storage. The awarded projects must have an in-service date of Dec. 31, 2030.

The New York State Energy Research and Development Authority is administering the request for proposals through its Bulk Energy Storage Program. The procurement is technology-neutral, but projects with durations of less than eight hours must use technologies that have been previously commercially deployed and interconnected, though not necessarily within the state.

Projects over eight hours must score an 8 or higher on NYSERDA's "technology readiness level" scoring *system*, indicating that demonstration-scale projects or technologies near commercialization are eligible to apply. They also must submit a plan that includes a "reasonable pathway" to securing an interconnection agreement.

Why This Matters

The New York Public Service Commission approved a target of deploying 6 GW of energy storage by 2030 last year.

NYSERDA will compensate project owners with Index Storage Credits, each representing 1 MWh of energy storage capacity that is operational and available to discharge. Projects will be credited and compensated based on the operational capacity they achieve each month over the course of 15- to 25-year contracts.

No ISCs will be paid out for a project until it is permitted, installed and operating. The projects also must pass a peer review process and quality assurance inspections.

New York Gov. Kathy Hochul | *New York Governor's Office*

NYSERDA-supported energy storage projects will be contractually obligated to meet new safety codes adopted *recently* into the Uniform Code by the State Fire Prevention and Building Code Council. The codes do not go into effect until next year, but NYSERDA has already adopted them into all of its storage programs. Each project must also submit a safety and security plan.

"Battery energy storage is key to keeping New York's electrical grid reliable, storing power for when it's needed most, especially during peak demand and extreme weather," New York City Fire Department Commissioner Thomas Von Essen and other former fire officials said in a *press release* released the same day as Hochul's announcement. "With proper oversight, clear protocols and continued training for emergency responders, battery energy storage can and should be safely integrated into our communities."

The state is seeking a minimum of 35% of the procured capacity to be deployed in New York City, its upstate suburbs and Long Island, with 30% in the city.

Developers have the option to submit an analysis of whether their projects will provide "electricity system value": how they impact the grid in terms of current reliability, future reliability, renewable integration, renewable curtailment and peaker plant displacement.

Project developers also need to conduct an analysis of their sites for flood risk, sea-level rise and extreme weather. If a climate risk is identified, the developer needs to address reliability and performance in the face of climate hazards.

"Today's action is another example of New York's ongoing commitment to strengthening our grid, ensuring the state continues to have a more affordable and reliable electricity system now and well into the future," Hochul said.

"Energy storage will provide many benefits to a modern power grid, including the ability to fully harness our most cost-effective energy solutions in wind and solar," Alliance for Clean Energy New York Executive Director Marguerite Wells said in a statement. "We thank Gov. Hochul for putting ratepayers first by prioritizing this safe and important technology." ■

NYISO Presents Informational CAFs for Non-firm Generators

By Vincent Gabrielle

NYISO on July 22 provided a glimpse into the *possible capacity accreditation factors* for gas generator units that have not guaranteed a supply of fuel for the winter capability period.

The informational capacity accreditation factors (iCAFs) — so called by the ISO because they are "for informational purposes only, utilizing information available at the time of calculation" — for non-firm generators in New York City and Long Island are 91.4 and 97.98%, respectively.

Speaking to the Installed Capacity Working Group, Pallavi Jain, manager of NYISO's capacity accreditation program, said these relatively high figures were driven by the number of dual-fuel units in those areas.

For the upstate, western and northern New York, the non-firm iCAFs were rated at 88.85%. This confused several stakeholders who had assumed that because the fuel constraints assumptions in the state's installed reserve margin do not apply outside of New York City, the city's suburbs and Long Island, the figures for upstate would be much closer to 100%.

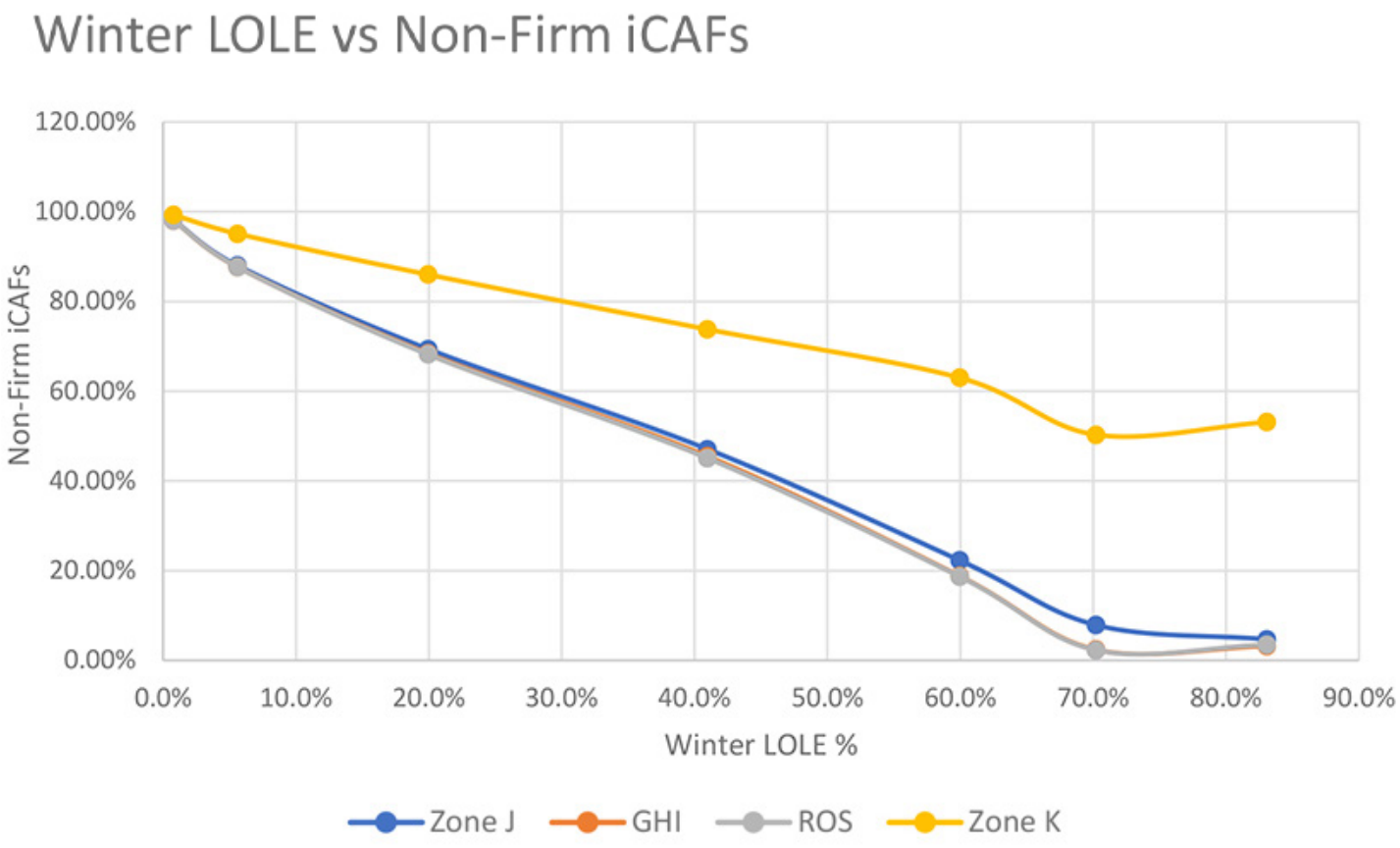
Doreen Saia, chair of the natural resource practice at Greenberg Traurig, pointed out that the tariff language FERC approved the week before does not allow for generators in those areas to opt "firm" at all because they are assumed to be firm. (See *FERC Accepts NYISO's Firm Fuel Tariff Revisions*.)

NYISO also presented an *update* to its proposed changes for capacity market parameters ahead of the Champlain Hudson Power Express' entry to the market. (See *NYISO Proposes ICAP Changes for New Entry Ahead of CHPE*.)

The ISO would run two IRM studies: one assuming the new resource (in this case CHPE) is in service, 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.

Stakeholders had asked that the ISO not use two sets of ICAP market parameters if the resource in question does not enter into the ICAP market during peak summer months. NYISO now proposes revising the ICAP parameters only if the resource enters the market prior to November. If the resource doesn't enter the market during the summer period (which ends Nov. 1), the ISO would keep the market parameters from the summer in place for the whole capability year.

The advance notice timing remained unchanged after stakeholders requested that the ISO consider incorporating more flexibility into the process. ■



Graphical representation of winter LOLE and 2024/25 non-firm iCAFs | *NYISO*

PJM Capacity Prices Hit $329/MW-day Price Cap

By Devin Leith-Yessian and Rich Heidorn Jr.

PJM capacity prices soared to $329.17/MW-day (UCAP) RTO-wide for delivery year 2026/27, hitting the price cap approved by FERC after prices rose nearly 10-fold in the July 2024 auction.

The clearing price is the highest in PJM history and an increase of $59.22 (22%) from last year's record for the RTO.

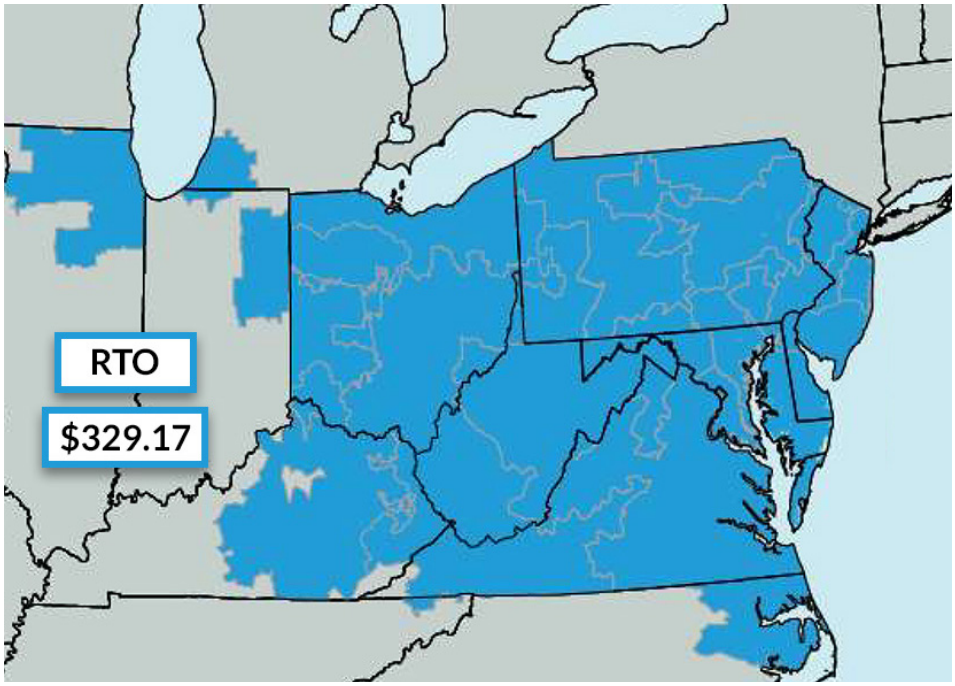
Prices would have hit $388.57/MW-day without the cap, PJM said in its report on the auction. The cleared supply totals $16.1 billion, up 9.5% from the $14.7 billion last year.

"This is a continuation of trends that we've been seeing: a tightening of the supply and demand conditions," Stu Bresler, executive vice president of PJM market services and strategy, said in a press briefing after results were announced July 22.

PJM's forecast peak load for 2026/27 increased by 5,446 MW from last year due to data center expansion, electrification and economic growth. "It's probably a true statement to say that the majority of the demand increase we saw was … those data center additions," Bresler said.

However, prices fell in the Baltimore Gas and Electric (BGE) and Dominion zones, which cleared at $466.35/MW-day and $444.26/MW-day respectively last year. Thus, although the increased capacity costs will boost many retail customers' bills by 1.5 to 5%, Dominion customers could save money, Bresler said.

Supply offered dropped 500.5 MW (UCAP) to 135,191.8 MW. New generation and uprates totaled 2,669 MW, the first increase in the past four auctions. In addition, 17 generating units with 1,100 MW of Capacity Interconnection Rights withdrew their retirements since the 2024 results were announced.



PJM capacity prices cleared at $329.17/MW-day (UCAP) RTO-wide for delivery year 2026/27, hitting the price cap approved by FERC after prices rose nearly 10-fold in the July 2024 auction. | *PJM*

Why This Matters

The 2026/27 capacity auction design has been the subject of several rule changes and FERC complaints, including a settlement between PJM and Pennsylvania Gov. Josh Shapiro to lower the maximum clearing price.

"We were pleased to see the new resources and the uprates that came in," Bresler said. "We're pleased to see the reversals of retirements, because that's the kind of thing we need and the kind of thing that one would expect from the collection of information that's out there, including the results of the last capacity auction." The Base Residual Auction (BRA) procured 134,311 MW of unforced capacity generation (UCAP) and demand response. Regions under the Fixed Resource Requirement acquired an additional 11,933 MW (UCAP) for a total of 146,244 MW (UCAP).

The reserve margin is 18.9%, 309 MW ICAP lower than the target of 19.1%.

Cleared resources were dominated by natural gas (45%), nuclear (21%) and coal (22%), with contributions from hydro (4%), wind (3%) and solar (1%). Declining fleet-wide accreditation values pushed the amount of supply offered down by about 326 MW from the 2025/26 BRA. PJM's auction *report* stated that 3 GW less gas was offered in the 2026/27 auction.

An additional 2 GW of wind generation cleared in the auction, followed by 867 MW of coal and 578 MW of oil. While the amount of DR offered was nearly flat, the resource class saw a significant drop in its effective load-carrying capability (ELCC) rating, causing the amount of UCAP clearing to fall by 224 MW.

Bresler said almost every resource that submitted offers cleared, aside from one that had its minimum offer set above the maximum clearing price. He said the results follow a trend of tightening supply and demand in recent auctions, which PJM has argued could lead to a capacity shortfall in the 2029/30 delivery year.

"I think this auction, just as the last one, served its purpose and very transparently reflected supply and demand," Bresler said.

RMR Impact

Bresler said including generators on reliability-must-run (RMR) agreements as supply helped dampen prices and reduced constraints, allowing BGE and Dominion to clear along with the rest of the RTO.

"I think that there was a significant impact from including the RMRs at zero [dollars] in the supply stack, and … there were

probably transmission upgrades going into place that changed the transmission import capabilities for those two zones as well," Bresler said. "So, even without the lower cap, we still would not have had price separation in this auction."

In the 2024 auction for 2025/26, the clearing price for most of the RTO jumped to $269.92/MW-day, the result of load growth, generation deactivations and changes to risk modeling that shrank reserve margins. (See *PJM Capacity Prices Spike 10-fold in 2025/26 Auction*.) The 2024/25 auction had seen a price of $28.92/MW-day for most of the RTO, with BGE hitting $73/MW-day.

Pa./PJM Settlement Lowered Clearing Prices

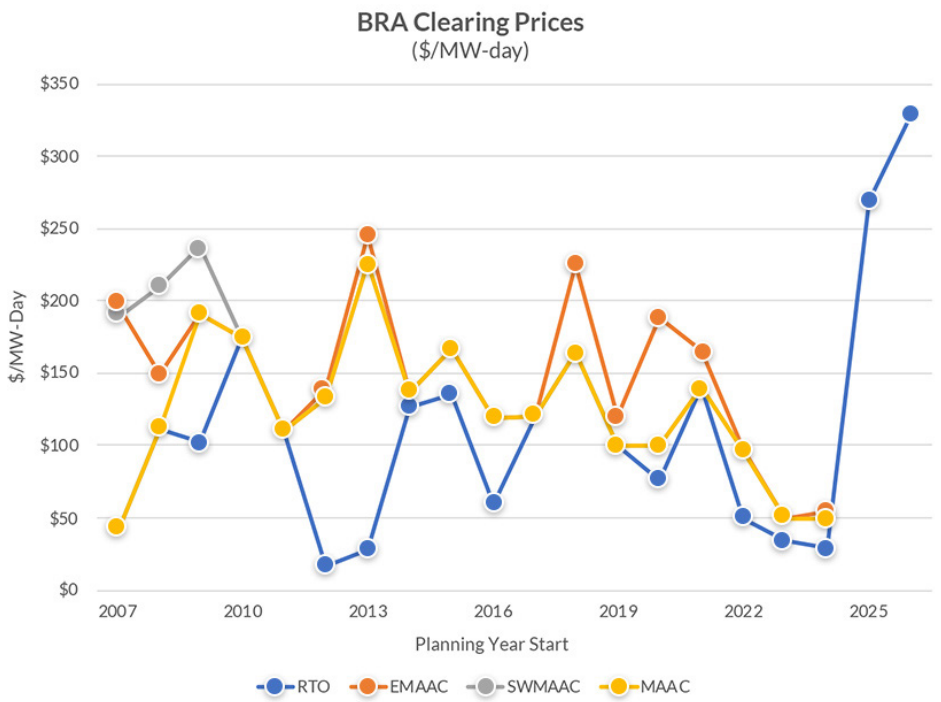
The 2026/27 auction design has been the subject of several rule changes and FERC complaints, including a settlement between PJM and Pennsylvania Gov. Josh Shapiro (D) to lower the maximum clearing price to $325/MW-day and establish a $175/MW-day floor. The settlement is effective for the 2026/27 and 2027/28 auctions (ER25-1357). (See *FERC Approves PJM-Pa. Agreement on Capacity Price Cap, Floor*.)

While the price band initially would be set at $175 to $325/MW-day, those values would be readjusted annually based on the accreditation of the reference resource.

PJM and the governor argued the settlement would stabilize prices while several market changes are implemented. A complaint filed by Shapiro's office said a lower maximum price was needed as the capacity market is unable to send adequate price signals under a compressed auction schedule and while the interconnection queue remains backlogged, preventing developers from bringing new supply in response to high prices (*EL25-46*).

In a *statement* following the posting of the auction results, Shapiro said the settlement avoided "grossly excessive price increases" and saved consumers $8.3 billion.

NRDC Senior Advocate Tom Rutigliano said the settlement prevented windfall payments to generation owners without compromising on reliability. He said the resulting price signals are ample to maintain existing resources and support new development and so long as there are barriers to new entry, such as the backlogged interconnection queue, higher prices would have served no purpose.



Base Residual Auction clearing prices by beginning delivery year for the RTO, EMAAC, SWMAAC and MAAC Locational Delivery Zones. All four LDAs cleared at $329.17 for 2026/27, a $59.25 (22%) increase from $269.92 for 2025/26. | *PJM*

In a statement, Illinois Citizens Utility Board Executive Director Sarah Moskowitz noted the settlement blunted capacity prices but argued the spike in capacity prices remains unacceptable and follows policy shortcomings at PJM.

"The power grid operator's policy decisions too often favor outdated, expensive power plants and needlessly block low-cost clean energy resources and battery projects from connecting to the grid and bringing down prices. This extended price spike was preventable. It ramps up the urgency of implementing long-term reforms at PJM and comprehensive energy legislation in Illinois, such as the Clean and Reliable Grid Affordability Act, to protect customers from price spikes that serve only to give power generators windfall profits," she said.

Auction Design Changes

PJM also received FERC approval to rework several market components, including modeling some resources operating on reliability-must-run agreements as supply in the capacity market (*ER25-682*). One of the factors that drove a spike in capacity prices in the 2025/26 BRA was two generators leaving the supply stack to begin running as RMR resources — the 1,289-MW Brandon Shores coal plant and the 843-MW H.A. Wagner oil-fired plant. (See *FERC OKs Changes to PJM Capacity Market to Cushion Consumer Impacts*.)

The filing also established an RTO-wide non-performance charge rate and maintained the reference resource for the 2026/27 auction as a combustion turbine, rather than going through with a scheduled shift to a combined cycle unit.

This is the first auction in which intermittent, storage and hybrid resources holding capacity interconnection rights (CIRs) were required to submit capacity offers. FERC granted PJM's proposal to eliminate an exception from the capacity must-offer requirement for those resource types after the RTO said there was about 1.6 GW of capacity not offered. PJM argued that requiring all resources holding CIRs to submit capacity sell offers will prevent the exercise of market power and more accurately reflect supply and demand (*ER25-785*).

The order eliminating the must-offer exemption also established an alternative market seller offer cap (MSOC) set at a resource's capacity performance quantified risk (CPQR). The filing argued the change would allow intermittent and

storage resources to more accurately reflect the risks they face by taking on a capacity obligation.

Rising capacity clearing prices, and wholesale market costs generally, have been a source of consternation for consumer advocates and political leaders across many PJM states. Both Pennsylvania and New Jersey have raised the specter of leaving the RTO if reliability and cost concerns go unanswered. In July, nine governors signed onto a *letter* requesting that the qualifications for candidates to replace CEO Manu Asthana and to fill two open Board of Managers positions include the ability to restore public confidence and address "difficult decisions that could substantially raise consumer bills."

"In the past, other regions looked to join PJM due to its many strengths; today, across the region, discussions of leaving PJM are becoming increasingly common," the letter said. "These unwelcome developments reflect legitimate concerns about PJM's trajectory. We write, as a bipartisan group of governors elected by the many millions of citizens of our respective states, to tell you that fundamental changes, and new leadership, are needed to restore confidence in PJM's ability to meet the many challenges of this moment."

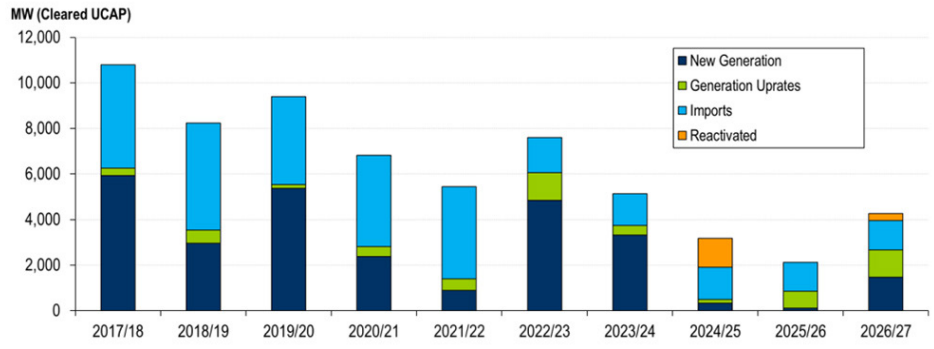
Rutigliano said prices increased due to the combination of increasing data center demand and risk modeling capturing reliability issues with gas generation. Without the increase in wind generation, he said PJM would not have been able to meet reliability standards, underscoring the need for PJM to continue clearing its interconnection queue and for states and the federal government to address siting and permitting barriers.

"The bright spot in this auction is a 75% increase in wind and solar. That jump will save PJM from an unacceptable risk of blackouts in 2026. PJM will stay reliable in 2026 thanks to the increase in renewable power. However, these low-cost resources still only account for 4% of the PJM's supply, so PJM must continue to significantly speed up approvals of the 85 GW waiting to connect. The only real solution to higher energy prices is to keep adding more renewable energy and storage to the grid," he said in a statement.

Rutigliano told *RTO Insider* that states pushing for winterization of gas plants and PJM easing its restrictions on external resources selling capacity into PJM could buy the RTO at most two years before reliability issues become paramount, but the long-term solution lies in ensuring that renewable penetration accelerates.

Advanced Energy United Policy Director Jon Gordon said the auction results show that new resources are needed to meet forecast demand. However, long interconnection queues prevent developers from bringing new supply to market. He said fast-track study processes, advanced transmission technologies, load flexibility and virtual power plants can facilitate new entry while PJM advances its cluster-based interconnection study process.

"When prices go up, it's meant to send a signal to energy developers: 'We need more supply.' But at the same time, PJM is holding up a big red 'STOP' sign to energy developers," Gordon said. "Many projects have been stuck in the closed queue for over six years, a significant delay that adds additional risk and cost for developers and is likely to contribute to some otherwise viable projects never getting built.



Cleared new generation, uprates, imports and reactivated capacity by delivery year | *PJM*

"Given the magnitude of this crisis, PJM, transmission owners, project developers and states need to do everything they can to move projects in the current interconnection process through to completion while finding additional ways to accelerate the interconnection process immediately. The high auction prices underscore the urgency of allowing project developers to begin to propose new projects for the queue that reflect today's economic realities and come online in time to lower prices and ensure resource adequacy."

PJM Power Providers Group (P3) President Glen Thomas said the capacity market is successfully delivering reliability at a price that remains below surrounding regions.

"The auction results show a market that is responding but remains tight. New generation is being added, existing generation retained, external capacity imported and retired capacity reactivated. The resource mix remains diverse, and it is important for the market to continue to send the signal that more capacity is needed. In the meantime, consumers should feel comforted that PJM has secured capacity commitments sufficient to maintain reliability through May of 2027 at a price below what many other regions of the country are paying," he wrote in a statement.

Electric Power Supply Association CEO Todd Snitchler said the auction prices show new resources, not political interventions, are urgently needed.

"Higher prices are a signal to build more generation resources, and reflect increasing stress on the system," Snitchler said. "In recent years, a combination of state and federal policy shifts and poor market signals led to the premature retirement of essential generation. Now, as demand grows and supply tightens, we can't ignore the consequences of past decisions, and we must accept that reliability comes at a cost. Investment follows clear, consistent rules."

He argued that competitive wholesale markets have kept energy prices stable and efficient, whereas rising retail rates can be attributed to state policy mandates, as well as transmission and distribution spending not subject to the same transparency and market pressures. ■

State Governors Seeking Ability to Nominate 2 Members to PJM Board

By Devin Leith-Yessian

PJM member states are seeking the ability to nominate two candidates to the RTO's Board of Managers as they grow increasingly vocal about their dissatisfaction with the affordability and reliability of the grid.

During the Members Committee meeting July 23, Virginia Energy Director Glenn Davis read a statement from nine state governors calling the status quo unsustainable and arguing PJM must take concerted, rapid action, including a new vision for how the RTO interacts with the states.

To that end, the governors called for a permanent process for the states to nominate candidates to fill two of the seats on the nine-member board. Candidates are selected by the Nominating Committee (NC), which is composed of representatives from each of PJM's five membership sectors and three from the Board of Managers. Nominees are approved by the MC.

The statement was signed by the governors of Delaware, Illinois, Kentucky, Maryland, Michigan, New Jersey, Pennsylvania, Tennessee and Virginia. They argued there should be a formal role recognizing the shared responsibility of PJM and its member states to ensure affordable and reliable electric service.

That could take the form of a new organization where representatives of governors' offices publicly meet with RTO leadership and stakeholders, they wrote. Such an association would allow the states to better understand the political and economic ramifications of data center load, and it would provide PJM with more intimate knowledge about the policymaking and discussions occurring in statehouses, they argued.

The governors had requested a meeting with the NC to recommend two candidates to fill open seats on the board and speak to their merits in a *letter* to the board July 16. They argued there is a crisis of confidence in the grid operator's leadership that requires the appointment of "distinguished, widely respected individuals." The governors said they have several candidates in mind.

Jacob Finkel, deputy secretary of policy for Pennsylvania Gov. Josh Shapiro, speaks to PJM stakeholders. | *© RTO Insider*

"At a time of rapidly rising load growth, PJM's multiyear inability to efficiently connect new resources to its grid and to engage in effective long-term transmission planning has deprived our states of thousands of jobs and billions of dollars in investment that may flow to other regions," the governors wrote. "Now these deficiencies threaten the bedrock reliability and affordability our consumers expect and deserve. We are deeply concerned that PJM's response has been typified by halting, inconsistent steps and rising internal conflicts within the stakeholder community that have recently culminated in the abrupt termination of two longstanding members of the Board of Managers and the imminent departure of the CEO."

The NC responded with its own *letter* declining to meet with the states, stating that it felt that a wider conversation open to all the RTO's stakeholders would be more beneficial. The committee also said PJM's Code of Conduct prohibits it from considering candidates who had not submitted applications to the independent consultant retained for the candidate search, Korn Ferry.

The board also *responded*, inviting the states to attend the July 23 MC meeting and outlining PJM's efforts to operate markets capable of delivering reliability at least cost while navigating an "explosion of demand growth" and generation deactivations, some of which have been prompted by state policies.

The nine governors (along with those of the other four states in PJM: Indiana, North Carolina, Ohio and West Virginia) are also planning to hold a technical conference to publicly discuss "organizational and market reforms at PJM, and to establish an active participatory role for member states and jurisdictions." The conference is *scheduled* for Sept. 23 at the National Constitution Center in Philadelphia. Ohio Gov. Mike DeWine supported the nomination proposal in his own *letter*.

PJM and Stakeholder Responses

PJM Senior Vice President of Governmental and Member Services Asim Haque said staff have been very engaged with state executives and legislators. He said one of the most controversial decisions PJM has recently made was entering into a settlement with Pennsylvania Gov. Josh Shapiro to lower the maximum capacity clearing price and establish a price floor. (See *FERC Approves PJM-Pa. Agreement on Capacity Price Cap, Floor*.)

"Expect for that engagement to continue, and should you form a formal organization, we would support that as well," he said.

He added that PJM already spends a great deal of time working with the Organization of PJM States Inc. (OPSI), though he said that does not mean the RTO could not engage with another organization representing state interests.

CEO Manu Asthana said the states have a major role in PJM, and their priorities deserve careful attention.

"I think we should build upon the excellent participation and voices of the states we already have at OPSI," he said.

Jacob Finkel, Shapiro's deputy secretary of policy, said the governors have a desire to play a more active role in PJM decision-making than the more responsive position OPSI has often been forced to take.

Paul Sotkiewicz, president of E-Cubed Policy Associates and former PJM chief economist, said he believes the notion that states should have a role in selecting board membership comes dangerously close to violating PJM's independence, adding that RTOs are not a creature of the states, but rather of the federal government.

Sotkiewicz questioned whether states seeking greater engagement with PJM are prepared to take ownership and responsibility for RTO decisions and their consequences.

Finkel said the final decision over board appointments would remain with the PJM Members Committee, and the governors are not seeking anything that would run afoul of FERC Order 2000. Rather, they want to avoid PJM coming to state capitols and explaining that its markets are not functioning properly or interfacing well with state policies by having the states play a role in getting the market design right in the first place.

Board Chair David Mills said he doesn't believe PJM has come to the states to say it has bungled market design, but out of a desire to collaborate. Those efforts can be undermined, however, when state officials discredit the RTO or make threats to withdraw, which can harm investor confidence, he said. ■

PJM Stakeholders Reject 2027/28 Capacity Auction Parameters

By Devin Leith-Yessian

VALLEY FORGE, Pa. —Stakeholders rejected the installed reserve margin (IRM) and forecast pool requirement (FPR) values *recommended* by PJM staff, with some opposed arguing that the inputs remain nebulous.

The July 23 Markets and Reliability vote received 65% sector-weighted support, just short of the two-thirds threshold; a second vote at the Members Committee also failed with 63% sector-weighted support.

The proposal would increase the IRM to 20% for the 2027/28 Base Residual Auction (BRA), up from 19.1% in the auction prior, while the FPR would increase from 0.9170 to 0.9260. PJM's Josh Bruno said both are increasing because of PJM's risk modeling skewing more heavily toward the winter. (See "Stakeholders Discuss Revised IRM and FPR Values for 3rd Incremental Auction," *PJM PC/TEAC Briefs: Jan. 7, 2025*.)

Paul Sotkiewicz, E-Cubed Policy Associates | © RTO Insider

Paul Sotkiewicz, president of E-Cubed Policy Associates representing J-Power USA, said the effective load-carrying capability modeling behind resource accreditation and risk modeling is poorly understood by market participants, and its results are unreproducible.

"This is a black box — people still don't understand how anything is put together, and you can't run a market … by doing this as a black box. So, we really need to consider taking our time and really hearing out what needs to be done here," he said.

Exelon's Alex Stern noted that few of the 500 eligible voting members voted on the proposal, with the final MC vote reflecting 45 ballots cast in favor, 25 cast in opposition and 15 abstentions.

Bruno said 198 GW of installed capacity is expected to be available, up 4.6 GW, equating to 163 GW of solved load, a 2.5-GW increase. The increase comes from transmission headroom being allocated to existing resources through transitional capacity interconnection rights, new wind and solar resources, and increased demand response accreditation driven by the resource's availability window being expanded. (See "PJM Announces Transitional Headroom Allocations," *PJM PC/TEAC Briefs: May 9, 2023* and *PJM Stakeholders Endorse More Detailed Demand Response Modeling*.)

The Bottom Line

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said most of the advocates planned to vote against the proposal due to endorsement being sought on the same day as the values were brought for a first read. That left little time, he said, to review and ask questions, particularly about the cost impacts of the increase to the reserve margin.

Most resource classes would see their accreditation remain within three percentage points of their ratings for the 2026/27 BRA. DR, however, saw its rating increase 23 points, and storage resources of all durations saw their ratings increase between six and nine points.

Much of the increased winter risk is because of the steady pace of anticipated data center growth. Because winter falls toward the end of the delivery year, Bruno said more large loads are expected to have come online by that time.

Rebecca Stadelmeyer, of Gabel Associates, said there is a disconnect between the load forecast and the delivery year and raised the request to all companies conducting their analysis now to take a more granular look at data center milestones and ensure the online months align more accurately.

James Wilson, PJM | © RTO Insider

James Wilson, a consultant for several consumer advocates, said data center growth and its relation to seasonal risk is a short-term phenomenon PJM should prevent from causing distortions to the investment signals sent by the capacity market. He acknowledged that capacity auctions print one-year price points but argued that should not be incongruent with the goal of guiding long-term investment.

Greg Poulos, CAPS | © RTO Insider

Greg Poulos, executive director of the Consumer Advocates of the PJM States, said most of the advocates planned to vote against the proposal because endorsement was being sought on the same day as the values were brought for a first read. That left little time, he said, to review and ask questions, particularly about the cost impacts of the increase to the reserve margin. He also questioned whether it is appropriate for PJM to increase the IRM given the tightening supply and demand in recent auctions. Raising the prospect that not doing so could result in more frequent DR deployments, he argued that curtailment service providers are being paid to be available and not using them undermines their value.

Susan Bruce, representing the PJM Industrial Customer Coalition, said consumers and DR participants have gotten a lot of questions about the parameters presented for the 2027/28 auction just a day after the results for the 2026/27 auction were posted. She said it's unfortunate the membership is being asked to make decisions on a topic so dependent on the results of 2026/27 BRA with so little time to consider the implications. ■

PJM MRC/MC Briefs

Markets and Reliability Committee

Stakeholders Endorse SATA Issue Charge

VALLEY FORGE, Pa. — The PJM Markets and Reliability Committee endorsed by acclamation an *issue charge* by Constellation Energy focused on how storage as a transmission asset (SATA) could be implemented in the RTO.

Constellation's language built on a PJM *issue charge* and sought to add consideration of potential market impacts when a SATA unit responds to a constraint. It added key work activities to identify the transmission use case for SATA, identify and address market impacts, develop rules for prioritizing SATA dispatch over market-based resources and consider rules to mitigate price impacts. (See "Stakeholders Bring Alternative SATA Issue Charges, Endorsement Delayed," *PJM MRC/MC Briefs: June 18, 2025*.)

An additional *issue charge* was offered by Exelon, which its director of RTO relations and strategy, Alex Stern, said was distinguished from Constellation's proposal by including a deeper exploration of overlapping benefits that SATA could have in planning and operations. Stern withdrew the utility's proposal and threw his support behind Constellation's offering.

All of the issue charges shared a six- to nine-month timeline and assigned the work to the Operating Committee.

PPL's Robin Lafayette, co-sponsor of the Exelon proposal, said there has been a lot of education and discussion on SATA over the years and, while he does not want to shortchange generation owners' concerns about market impacts, by ensuring that the rules will be clearly defined, there can be progress on developing proposals.

"We need to get this out of the issue charge space and get this to the place where we can get some practical progress on storage. We see this as one tool in the toolbox" to address the transmission needs PJM is forecasting, he said.

Vistra's Erik Heinle said the company wants to ensure storage has the capability to serve as a market asset in PJM, while avoiding the possibility for rate-based storage to cause negative impacts to resources participating in the markets.

Independent Market Monitor Joe Bowring said it's essential that transmission owners not own assets that are directly competing with market resources, a possibility he said could arise from PJM's language. He said that's especially true as some utilities are stating that they support going back to cost of service.

PJM's Dave Anders said staff support considering a ruleset for dual-use storage providing both market and transmission services, but doing both at once would be "exceptionally time consuming," and there is a preference for ensuring the transmission solution is fully thought through first.

Stakeholders originally considered the subject around five years ago before deferring the subject in February 2021. PJM revived the topic earlier this year, leading to a series of educational sessions at the OC.

Balancing Operating Reserve Revisions Endorsed

Stakeholders endorsed a *proposal* to rework the calculation of uplift credits and deviation charges to look at how resources follow dispatch instructions over time. (See "Stakeholders Narrowly Endorse Uplift Changes," *PJM MIC Briefs: April 2, 2025*.)

The new tracking ramp-limited megawatt desired (TRLD) metric would look at the difference between what a resource's output would be had it followed its economic basepoints versus its actual output for each five-minute interval. The current metrics are limited to considering output during each interval, which can lead to resources facing little to no deviation charges, or collecting uplift, while keeping their output flat contrary to PJM instructions.

PJM Senior Director of Market Settlements Lisa Morelli said the proposal also includes changes to the balancing operating reserve (BOR) calculation intended to simplify the calculation and limit make-whole payments to the amount of uplift that would be owed if a resource owner followed instructions. The proposed formula would determine a unit's BOR credit to be the lesser of its real-time output or TRLD value. The start and end points for uplift eligibility would be revised to align with when a market seller's commitment began and to run through either the end of that commitment or the unit's minimum run time.

The proposal includes a phased rollout, where simulated settlement results would be presented to market participants a year before the changes are fully implemented. It was jointly sponsored by PJM and the Monitor at the Market Implementation Committee, where it was endorsed with 53.3% support.

Heinle said there are concerns about the proposal, but the soft launch is a good idea to provide market participants an opportunity to adjust to the changes and so any unintended consequences can be addressed.

Reworked Dual-fuel Definition Endorsed

The committee endorsed by acclamation a quick-fix *proposal* to revise the definition of dual-fuel gas generation to include resources where the alternate fuel is stored off-site but connected with "a firm pipeline that is solely dedicated to the market seller's resource(s)."

The quick-fix process allows an issue charge to be voted on concurrent with a proposed solution.

While stakeholders workshopped the precise Reliability Assurance Agreement revisions included in the proposal during the July 23 meeting to avoid it applying to configurations where there would not be a firm supply of the alternative fuel, there was widespread support for the changes.

Bowring said the proposal illustrates the difficulties of trying to pursue changes in a quick-fix space and suggested deferring another meeting to allow the language to be tightened. He said there is not underlying disagreement with the language brought by Dominion Energy, but rather with its precision.

Members Committee

PJM Presents Capacity Market Feedback Poll

PJM Executive Vice President of Market Services and Strategy Stu Bresler presented the *results* of a poll querying

stakeholders on what changes to the capacity market they believe should be prioritized.

When asked if any additional items should be added to the scope of the Quadrennial Review of the capacity market, 105 respondents said no additional issues should be considered, followed by "other components" with 74 votes and a prompt auction design with 58. When considering what should be tackled alongside how large load additions (LLAs) are incorporated into PJM's load forecasts, there was wide support for enabling greater participation for demand response and load flexibility. Outside of the Quadrennial Review and LLA issues, 161 stakeholders said a sub-annual market design should be a priority.

Bresler said the RTO is considering an expedited stakeholder process to reckon with large loads, which are a significant contributor to a capacity shortfall PJM is forecasting around the 2029/30 delivery year, along with generation deactivations outpacing new entry.

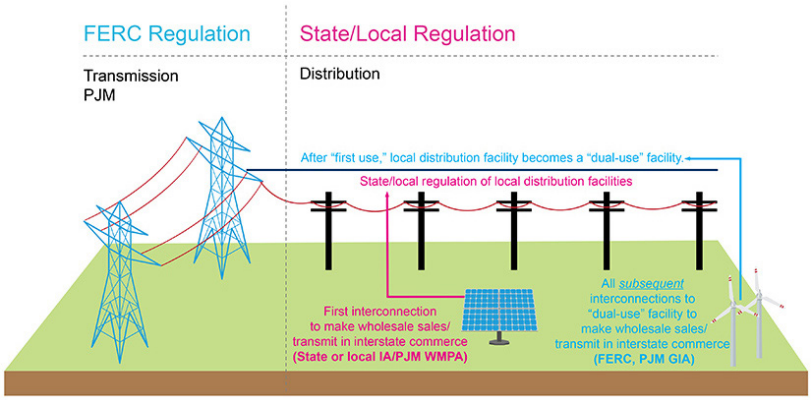
"We need to get a handle on these large load adjustments and do it quickly," he said.

The next step will be updating PJM's market design project *road map* to add high-priority items, with the aim of having those changes ready to present to the MIC on Aug. 8.

PJM Board of Managers Chair David Mills said the RTO barely cleared the reliability requirement in the 2026/27 Base Residual Auction, the results of which were posted on July 22, and unconstrained, dramatic load growth is expected for the next few auctions. (See related story, *PJM Capacity Prices Hit $329/MW-day Price Cap*.)

Load forecasting must be a priority, he said, along with any improvements that can be made to the 2028/29 BRA given that will see the sunsetting of a settlement between PJM and Pennsylvania to temporarily lower the maximum capacity clearing price and establish a price floor. Mills questioned if there is time within the stakeholder process to take on additional issues that don't move those needles.

Mills also said he worries that there has not been an adequate discussion with PJM states about the political consequences that could result from the RTO requiring data centers to bring their own generation, including the possible impact on job creation. Pushing for large load to self-serve a portion of their load was one of the solutions PJM discussed during a resource adequacy technical conference held by FERC. (See *RA Technical Conference Comments Urge a Variety of Market Reforms*.)



A PJM graphic shows the jurisdictional divide when resources interconnect to distribution or transmission facilities. | *PJM*

While semiconductor and water availability could prove to be constraining factors on data center growth, the clock is ticking, and stakeholders must move quickly, Mills said. "The demand impact of the data centers is going to completely outrun any gains we get."

Board member Margaret Loebl said one lens to view how PJM should prioritize addressing resource adequacy over the coming years is by identifying the subjects that present the greatest risk to ratepayers and the RTO's mission.

Once stakeholders figure out prioritization, board member Vickie VanZandt said, there will need to be a lot of speed with which solutions are pursued. There may need to be a "best evaluation and a leap of faith because we are out of time."

Gregory Poulos, executive director of the Consumer Advocates of the PJM States, said load growth is outstripping not only the available resources in the RTO, but also the amount of new entry that is expected. He said the bring-your-own-generation concept needs to be a core focus to ensure resource adequacy. He also faulted the PJM board for siding with members who supported delaying the implementation of a wider availability window for DR resources for the 2026/27 BRA, which he said would have improved reliability and added supply when it is needed.

Bill Fields, deputy of the Maryland Office of People's Counsel, said part of the discussion has to involve how to integrate data centers without burdening consumers. Acknowledging there is some rising data center growth in Western Maryland, he said by and large the state has done well at keeping its load flat. Nonetheless, it is seeing rising prices because of load growth in other regions. He said state legislators are growing increasingly frustrated with PJM's messages and skeptical of the benefits of remaining part of the RTO.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said much of the tightening of supply and demand is from political interference and years of low prices causing premature resource retirements. Now that prices are coming back up, he said there is a growing backlash.

"Markets can work if we allow them to work. If we continue fiddling with them … they're not going to work," he said.

Old Dominion Electric Cooperative's Mike Cocco said creative solutions will be needed, such as requiring interruptible service for some large load customers. There is also a growing concern about PJM's effective load-carrying capability causing a paper shortage on top of a real capacity shortfall.

While there is a need to recognize correlated outages, Cocco also said PJM's recent efforts to provide transparency show that much of the modeled risk comes from two events: the 2014 polar vortex and Winter Storm Elliott. PJM has made market and operational changes, such as the conservative operations protocol, since those events that have not been reflected in how the RTO values system risks, he said. ■

— Devin Leith-Yessian

FERC Approves Constellation Purchase of Calpine with Conditions

By James Downing

FERC approved Constellation Energy's $26.6 billion purchase of Calpine Corp., creating an IPP with nearly 60 GW of generation around the country (*EC25-43*).

In an order issued after the markets closed July 23, the commission found the deal, with divestment commitments and a settlement on bidding behavior with PJM's Independent Market Monitor, is in the public interest.

While Constellation is the surviving firm in the deal, Calpine's main owners — ECP and AI Holdings — each still will control less than 10% of the new firm, which is below FERC's standard for a controlling interest in a utility.

The mitigation plan includes selling off 3,546 MW of generation, all of it located in PJM, that comes from the 1,134-MW natural gas combined cycle Bethlehem Energy Center, the 569-MW dual-fuel combined cycle York Energy Center Unit 1, the 1,136-MW dual-fuel combined cycle Hay Road Energy Center and the 707-MW simple cycle gas-fired Edge Moor Energy Center.

The two firms have overlapping generation in ISO/RTOs around the country, but PJM is their biggest shared market, where, after consummation, Constellation will control 26.4 GW, or 14.9%, of its installed capacity. In some submarkets to the RTO, absent the mitigation plan, the merger would have given Constellation enough market power to fail standard screens, FERC said.

Constellation Energy Corp. headquarters in Baltimore | *Constellation Energy*

Constellation and the IMM signed a *deal* July 3 where the firm agreed to some post-merger behavioral commitments to deal with the monitor's concerns over its impact on market power. The deal is based on one that Constellation entered into with the IMM before the merger and extends behavioral commitments on its generation out to the 2035/36 capacity delivery year.

The deal prevents the firm from selling any of 3,546 MW of generation to be divested to Dominion Energy and American Electric Power, or their subsidiaries. The IMM could disagree on other deals, including seeking restrictions at FERC, but Constellation would be able to oppose those arguments.

The IMM settlement includes commitments for Constellation to bid into the capacity and energy markets at specific prices and requires notice for retirements. It also limits Constellation's ability to enter into co-location deals with large loads such as data centers.

"For a period of one year from the execution of this settlement agreement, Constellation agrees not to enter into any co-location arrangements under which the capacity serving the load delists, until and only if the commission issues an order, regulations or policy statement subsequent to the date of this agreement authorizing such a configuration," it said. "For the avoidance of doubt, nothing in this agreement restricts the ability of Constellation or the [PJM] IMM to advocate for any particular co-location configuration or restriction on such configurations."

FERC found the mitigation plan appropriately addresses market power concerns brought up by Constellation's acquisition of Calpine.

"We accept Constellation Energy's commitment to abide by the terms of the Constellation-PJM IMM agreements, and we condition our authorization of the proposed transaction on that commitment," FERC said.

Why This Matters

The deal is one of the largest to come out of the IPP sector in recent years and gives Constellation a huge chunk of additional generation in a time of generally rising prices.

The deal addresses market power concerns that the IMM and other intervenors made in the case, extending bidding rules Constellation already must follow in PJM to its newly acquired units and for an additional four years from the previous deal. Any changes to that deal before May 2036 would have to come before FERC to get approved, as the regulator is basing the deal's approval on the commitments made there.

Pennsylvania's Consumer Advocate asked FERC to weigh the impact of the merger on the state's competitive market and the default service auctions for customers who stay with the utility. FERC has said it would examine retail market impacts, but only if a state commission asks it to do so, and the PUC did not in this case.

FERC also was unpersuaded by protesters' arguments that it needed to examine the impact of ECP continuing to own less than 10% of the firm after the merger. Staying below that mark creates a rebuttable presumption that an entity lacks control.

"ECP and AI Holdings will each hold less than 10% of the voting equity interests in Constellation and will not have any right to appoint a board member to the boards of Constellation or any of its subsidiaries," FERC said. "Furthermore, applicants represent that there is no contract that gives ECP influence on the decision-making of Constellation or its public utility subsidiaries after consummation of the proposed transaction." ■

Stakeholders Support Sub-annual Capacity Issue Charge

By Devin Leith-Yessian

VALLEY FORGE, Pa. — The Markets and Reliability Committee endorsed an *issue charge* to hire a consultant to investigate the pros and cons of a sub-annual capacity market and what designs stakeholders feel would be feasible. The committee supported the proposal with 56.6% sector-weighted support, with end-use customers and transmission owners strongly in support and all others opposed.

Brought by Pennsylvania Gov. Josh Shapiro (D), the issue charge argues the annual auction is "suboptimal" and shifting to a sub-annual model can deliver affordable reliability in the face of projected resource constraints. The state's Deputy Secretary of Policy Jacob Finkel said a sub-annual design also would allow for greater alignment between the capacity market and system risks as the risk drivers in summer and winter diverge.

Finkel said the governor's office heard concerns shared by stakeholders that the original issue charge would have moved too quickly with the goal of filing a sub-annual design in the first quarter of 2026 for implementation in the 2029/30 Base Residual Auction (BRA). The document was revised further during the July 23 MRC meeting to clarify that it is focused on the consultant's work of preparing a report to be completed by the end of 2025. Drafting and voting on actual changes to PJM governing documents could follow with subsequent issue charges, but would not be part of the initial work, Finkel said. Language also was added to have the report include an addendum detailing comments provided by stakeholders.

What's Next

The issue charge calls for a consultant to complete a report by the end of 2025. Drafting and voting on actual changes to PJM governing documents could follow with subsequent issue charges, but would not be part of the initial work.

Vistra's Erik Heinle said he appreciates that stakeholder concerns were addressed by the revisions and suggested the consultant work with stakeholders to identify priorities for a seasonal design, such as how it could function, desired design components and what concerns exist. Such an approach proved effective in identifying changes to the financial transmission rights market after the GreenHat scandal. (See *FERC OKs GreenHat Settlements*.)

"It's already a stronger issue charge from what we saw last month," he said.

PJM Board of Managers Chair David Mills said he is agnostic about the proposal but appreciates that it takes a light touch and would outsource some work to a consultant, rather than putting additional workload on staff already working double and triple duty. Having a consultant study the possible benefits of a sub-annual design could be valuable before stakeholders engage in what could be a multiyear process, he said.

Prioritizing staff and stakeholder efforts will become increasingly important, Mills said, with the potential for any new generation coming online in upcoming capacity auctions to be consumed by accelerating load growth.

Gregory Poulos, executive director of the Consumer Advocates of the PJM States, said the advocates wish to pursue a sub-annual design with a lot of urgency, particularly with a settlement to lower the maximum capacity price and establish a price floor set to expire with the 2027/28 BRA. He said the issue may lend itself to an expedited process.

"There cannot be enough urgency put on this," he said.

Independent Market Monitor Joe Bowring said he hopes the language around a sub-annual design is intentional to include solutions beyond a seasonal design, such as an hourly market design. The Monitor made such a proposal during the 2023 Critical Issue Fast Path (CIFP) process. Finkel responded that the issue charge is explicit in exploring sub-annual, rather than just seasonal,

PJM board Chair David Mills | © RTO Insider

solutions. (See "Independent Market Monitor Adds Detail to Hourly Approach," *PJM Completes CIFP Presentation; Stakeholders Present Alternatives*.)

Bowring also said PJM's seasonal proposal would result in a doubling of offer caps and likely would result in much higher prices.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said when other RTOs sought to make similar changes to their capacity markets, they engaged in yearslong processes, whereas the issue charge would be considerably rushed.

Finkel said shifting the goal of the issue charge to a report on the feasibility and potential of a sub-annual design, rather than actual market changes, was intended to address concerns that the proposed process may have been faster than is feasible within the PJM stakeholder process. He added that there has been considerable stakeholder effort spent on discussing the subject since the capacity market first was implemented.

Carl Johnson, representing the PJM Public Power Coalition, said he doesn't believe the consultant can do the work detailed in the issue charge by December. He argued that a more granular market design alone wouldn't be effective without a holistic look at the volatility of the effective load-carrying capability model and the changing nature of the load forecast and the forecast's timing. ■

FERC Approves SPP's ERAS Process, Accreditation

By Tom Kleckner

SPP is celebrating several recent FERC orders that have strengthened its resource adequacy framework and will secure a "reliable energy future" for its region.

The orders came in a flurry of filings related to resource performance and a one-time, accelerated pathway for new resources to help meet reliability needs through 2030.

On July 18, FERC approved the RTO's performance-based accreditation (PBA) and effective load-carrying capability (ELCC) methodologies (*ER24-1317*). Three days later, the commission approved SPP's proposed *Expedited Resource Adequacy Study* (ERAS) that allows load-responsible entities to nominate qualified projects for fast-track reviews (*ER25-2296*). The ERAS approval is conditional upon the grid operator making a compliance filing within 30 days.

FERC also issued orders allowing SPP and MISO to include ERAS projects in their Joint Targeted Interconnection Queue (JTIQ).

SPP said the regulatory milestones are "pivotal steps" toward achieving the forward-looking RA posture it has championed in recent years.

"FERC's approval of these two cornerstone initiatives affirms SPP's vision and the collaborative spirit of our members, regulators and stakeholders," CEO Lanny Nickell said in a statement. "The ELCC and PBA methodologies provide a modern, fair and transparent approach to accrediting resources, and the ERAS process empowers our region to respond quickly to rapidly growing demand."

In making its ERAS filing in May, SPP said its region "is on the precipice of a resource adequacy crisis" and that it expects available capacity to drop below the balancing authority's reserve margins by 2027. It said the region might run out of capacity to meet peak demand in 2030, as the footprint's forecast demand has increased significantly. Data centers' large loads and other technologies have further accelerated increased demand, the RTO said.

SPP said it expects to grant generator interconnection agreements by the end of March 2026.

Eight governors from SPP states jointly filed in support of the ERAS proposal, and several regulatory commissions intervened. LREs said that ERAS complements, rather than supplants, the grid operator's reliability laws and processes because it offers an interconnection timetable that can accommodate resources that stem from competitive procurements already mandated by state law.

However, public interest groups and clean energy developers opposed the proposal, as they did when it went through the grid operator's stakeholder process. They argued that ERAS amounts to queue jumping, bypasses open access to the RTO and violates the FERC's principle of nondiscriminatory access to the grid. (See *SPP Board OKs 1-time Study for LREs' Gen Needs*.)

"This is an affront to open access and a major and significant problem for those exploring whether or not to invest in SPP," the Advanced Power Alliance's Steve Gaw said during the Board of Directors' consideration of the proposal.

FERC instead found that SPP has "existing authority" under its tariff to evaluate and maintain resource adequacy and to manage its interconnection queue to provide sufficient generation to meet RA requirements. It agreed with SPP that ERAS requests will receive a GIA "significantly sooner" than those processed through the RTO's normal study process.

"As SPP explains, the one-time, limited ERAS proposal will allow SPP to accelerate the study of interconnection requests that are uniquely 'shovel ready' and that have been identified to meet an LRE's near-term resource adequacy needs," the commission said. "The ERAS proposal will enable resources to meet projected near-term resource adequacy needs more quickly than could be accomplished under SPP's current interconnection [study] process."

FERC on July 21 also approved MISO's second attempt to create a fast track for certain reliability-related projects in the queue. It had rejected an earlier version in May. (See related story, *FERC Approves MISO Interconnection Queue Fast Lane*.)

Why This Matters

SPP says the FERC approval of 'cornerstone initiatives' will provide a modern and fair approach to accrediting resources and help the region respond quickly to rapidly growing demand. The RTO was expecting available capacity to drop below the balancing authority's reserve margins by 2027.

The American Clean Power Association said both ERAS orders are a "dangerous misstep" that ignore "widely acknowledged market realities while signing off on the potential for major disruption for projects that have gone through the proper processes to be connected to the grid."

"The fastest-growing sources of energy — solar, wind and energy storage technologies — are the ones ready to deploy to help keep costs lower and power reliable … across both territories," ACP's Carrie Zalewski, vice president of markets and transmission, said in an email. "Maintaining reliable and affordable power requires a diversified grid and predictable measures to bring new resources online."

Zalewski said the organization is committed to advancing its shared goal and responsibility "to ensure these approved requests do not set a precedent that will cause lasting damage."

She said states with higher amounts of clean energy have seen an increase in reliability and lower electricity prices on average. Zalewski cited the 2025 polar vortex — when prices rose only 20% in Texas and California but more than 135% in MISO — and SPP's performance during a summer 2024 heat wave as examples.

The fast-track process is expected to mostly produce gas-powered resources, according to the Sierra Club. It noted

several states in the RTOs' footprints have recently passed laws that allow utilities to increase rates to finance new gas-burning power plants years before they provide a service.

"FERC's decisions make it possible for gas plants to cut in line at the expense of thousands of clean energy projects that have been waiting for years to interconnect, projects that are well qualified to meet MISO's and SPP's energy needs," senior attorney Greg Wannier said in a *statement*.

SPP currently has more than 30 GW of thermal generation in its *queue*, or about 19% of the total.

ELCC, PBA Methodology Approved

SPP said FERC's approval of its modern accreditation methods for wind, solar and storage and a PBA for traditional resources affirms its "new, data-driven approach to resource accreditation."

The RTO said it will be able to more accurately measure each generators' reliability and ensure they are dispatched and compensated for their "real-world performance."

"This gives utilities and grid operators better tools to plan for and maintain a reliable grid," SPP said.

Commissioners David Rosner and Judy Chang filed a joint concurrence, noting "numerous" parties raised several methodological concerns with SPP's proposal.

"However, despite the concerns, commenters nonetheless appear to universally recognize that SPP's proposal is an improvement over the status quo," they wrote. "Given the growing urgency of the resource adequacy challenge in SPP, we are persuaded that the commission should accept this just and reasonable improvement."

SPP filed the tariff change in February 2024. The commission accepted the ELCC and PBA revisions, suspending both and consolidating them for paper hearings. That gave parties a chance to renew or modify their arguments after the grid operator added a fuel-assurance incentive to its PBA methodology. (See *FERC Approves SPP Price Formation Rules; Needs More Time on Resource Accreditation*.)

FERC rejected SPP's first attempt to add ELCC (the amount of incremental load a resource can dependably and reliably serve during peak hours) in 2023. (See *SPP Markets and Operations Policy Committee Briefs: Oct. 16-17, 2023*.)

JTIQ to Use ERAS

The commission also issued separate letter orders July 21 allowing SPP and MISO to include ERAS projects and coordinate their study in the RTOs' JTIQ initiative (*ER25-2297*, *ER25-2461*).

FERC found the proposed revisions to the joint operating agreement to be just and reasonable, saying they clarify how an affected-system coordination process built for multiphase cluster studies will apply to ERAS interconnection requests. The commission also said the proposed revisions ensure that ERAS requests meeting JTIQ criteria will be included in the initiative's portfolio.

The grid operators filed their identical JOA changes in May. The JTIQ framework enables MISO and SPP to develop a portfolio of "backbone network upgrades" to facilitate the interconnection of large amounts of generation near their joint seam. The framework includes a process for determining which requests from the RTOs' interconnection studies will participate in the JTIQ by identifying groups of eligible requests.

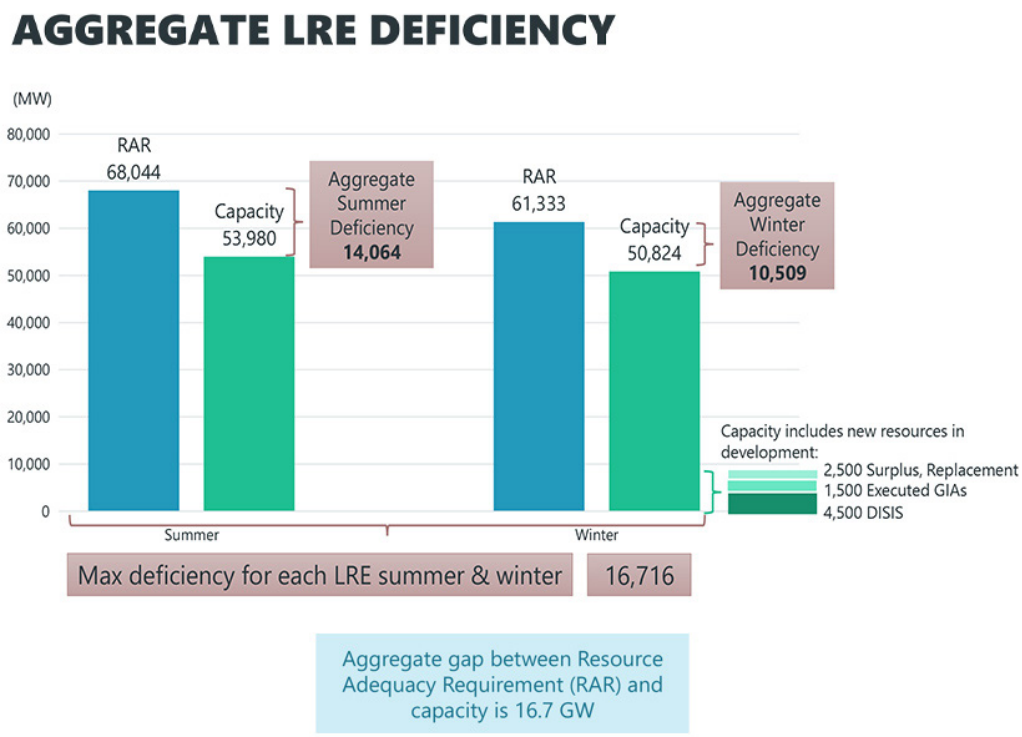
The SPP order is effective July 22 and the MISO order Aug. 6.

HVDC Interconnection OK'd

FERC also accepted in another letter order SPP's tariff revision outlining the planning process for evaluating the interconnection of HVDC facilities to its transmission system, effective July 23 (*ER25-2309*).

The commission said SPP's proposal set a general process for evaluating requests to interconnect HVDC facilities, including defining applicable terms, identifying relevant entities and their responsibilities, describing study processes for evaluating an HVDC request, and assigning responsibility for study deposits and costs.

It said the tariff revisions increase transparency into the HVDC interconnection planning process, with implementation details "further specified in the SPP planning criteria and related operational documents." FERC also found the revisions allocate responsibility for the interconnection study's costs to the HVDC customer. ■



SPP points to the 16.7-GW resource adequacy requirement as the need for its Expedited Resource Adequacy Study. | *SPP*

NextEra Energizes 2nd Competitive Project in SPP

NextEra Energy Transmission (NEET) has completed the second of its three competitive projects in SPP's footprint, the 92-mile, 345-kV *Wolf Creek-Blackberry project* in Kansas and Missouri.

NEET Southwest, a NextEra subsidiary, confirmed in an email to *RTO Insider* that the project was energized on July 16. It said the project was completed "within budget" and nearly five months ahead of SPP's required in-service date.

The project was awarded to NEET Southwest in October 2021. The developer's bid came in at $85 million, far below the high proposal of $151 million. (See "Expert Panel Awards Competitive Project to NextEra Energy Transmission," *SPP Board of Directors/Members Committee Briefs: Oct. 26, 2021*.)

Matt Pawlowski, NEET's vice president of development, celebrated the announcement during the July 17 Strategic Planning Committee meeting.

Interrupting himself mid-comment, Pawlowski said, "Did I mention that we energized Wolf Creek to Blackberry a couple days ago? I'm sorry, I think I forgot to mention that earlier. Did I? Did I mention that yet? No? OK."

In January, NEET Southwest also energized the *Minco-Pleasant Valley-Draper project*, a 48-mile, 345-kV transmission line in Oklahoma. NEET submitted a winning bid of $55 million for the project, which was awarded in 2022. (See "Directors Approve RTO's 4th Competitive Project Under Order 1000," *SPP Board of Directors/Markets Committee Briefs: April 26, 2022*.)

The projects are the only two of five approved by SPP under FERC Order 1000 that have been completed.

SPP also has awarded NEET Southwest *Crossroads-Hobbs-Roadrunner*, a 137-mile, 345-kV project in Southwestern Public Service Co.'s service territory in Texas and New Mexico. NEET's $291 million bid was higher than incumbent SPS' $220 million proposal, but the former offered a one-year construction timeline. (See *SPP Awards NextEra 3rd Competitive Project*.)

The project is scheduled to be completed by mid-2026. ■

— Tom Kleckner

NextEra Energy has now completed two competitive projects in SPP. | *NextEra Energy Transmission*

SPP Strategic Planning Committee Briefs

Committee Agrees with Staff's Approach to Speed Tx Development Capability

SPP's Strategic Planning Committee unanimously endorsed RTO staff's comprehensive approach to accelerate transmission capability, directing them and SPP's working groups to prioritize the development of policies for all short-, mid- and long-term initiatives.

Time is running short, Casey Cathey, SPP vice president of engineering, said during the July 17 meeting. Staff are currently producing solutions for the 2025 Integrated Transmission Planning assessment, which will be shared with stakeholders in October.

The ITP portfolio is expected to be another large one, possibly double that of the record 2024 assessment. That one produced 89 projects expected to cost $7.65 billion. (See *SPP Stakeholders Endorse Record $7.65B Tx Plan*.)

"We still have some work to do to solidify and optimize that total final portfolio, but we're still looking at a multibillion-dollar portfolio," Cathey told the SPC. "It may be in the realm of $15 billion. And so there is a notion that anything that we can do between now and November, we should probably do, recognizing that expedited revision requests and all of the things moving so fast this year has been problematic."

Noted teen philosopher Ferris Bueller said, "*Life moves pretty fast*. If you don't stop and look around once in a while, you could miss it."

But Cathey can't afford to stop and look around.

"We have to accelerate everything. We need to accelerate load. We need to accelerate generation. And so today's topic is accelerating all things transmission," he said.

Cathey said while SPP has added about $1 billion in transmission annually over the last decade, the evolving generation mix and growing reliability needs demand a faster and more targeted response.

Staff have proposed a multiphase strategy that speeds up transmission capability by: accelerating issuance of notifications to construct and timelines for selecting transmission owners under the competitive process; increasing deployment of near-term solutions; improving the efficiency of project completions; and addressing a diverse range of stakeholder perspectives.

SPP's Casey Cathey says there is no time to waste in accelerating transmission capability. | © RTO Insider

Gaining and obtaining the SPC's endorsement and guidance was the first step.

Christy Walsh, with the Natural Resources Defense Council, said she loved the focus on capacity.

"We need to build more transmission. We need more. We need to upgrade the biggest existing system as much as we can," she said. "We keep hearing it's going to take three to five years to build transmission. But we're also hearing we need capacity now for the new loads and whatnot. If we can squeeze more capacity out of the existing system … we should be doing that now while we're waiting the optimistic three to five years for the new transmission, and that's three to five years on top of the planning process."

Cathey agreed, saying staff are evaluating internal procedural barriers and coordinating with state and federal agencies to streamline permitting and construction efforts. The upcoming work will incorporate the strategies into long-range planning efforts and potentially shape future policy proposals.

Forecasting Mitigation Process OK'd

The committee unanimously endorsed its *Load Forecasting Task Force*'s proposed strategy to mitigate forecast risk in the SPP footprint and its impact on system planning.

The team has proposed improving consistency between forecasts used for resource adequacy and transmission planning purposes to address growing concern about under-forecasting load due to rapid economic growth, electrification trends and data center expansions. It says traditional forecasting methods may not fully capture emerging demand risks.

Oklahoma Gas & Electric's Brad Cochran, the task force's chair, said the group has been meeting for a year. During that time, it had several conversations with other grid operators about their practices.

"What we were finding through discussions is there's variability and timing of when entities are completing their forecasts and when they're updating them," he said. "We've talked extensively … about large loads and how fast they're coming.

Those forecasts change and those numbers change often, so aligning those two so you have similar information in both of these planning processes is a big deal."

The team recommended continuing to use separate load-responsible entity forecasts for RA and Integrated Transmission Planning (ITP) but require an update to the ITP forecast during the RA submittal window. It also advocated that SPP assess whether to develop in-house forecasting expertise, but not conduct forecasts for individual LREs.

"Because of the diverse footprint of SPP and the diverse membership at this time, the task force didn't think that it makes sense for SPP to develop these forecasts for all 60-plus LREs," Cochran said.

He suggested SPP have some level of expertise and knowledge to give it "the ability to kind of build and evolve over time and look at these forecasts and communication."

STRP Task Force Created

The SPC agreed to form a task force to help develop guidelines and a framework for reforming the process for considering short-term reliability projects (STRPs).

Irene Dimitry, an independent member of SPP's Board of Directors, will chair the task force, which will report to the SPC. The effort comes after several attempts by staff resulted in a framework that she said was "too prescriptive."

"Given our role as independent board members, we need the ability to each apply our own judgment in making decisions about what's best for SPP and its members and all the customers that we serve," she said.

SPP CEO Lanny Nickell said the focus for the task force should be, "How do we make it faster?" It has a January 2026 deadline for delivering meaningful plans to the SPC.

"Ultimately, we need to do whatever is needed to produce reliability upgrades, to produce economic value and optimize all of that to consumers in the region," he said. "We just need to make sure we recognize the fact that speed is of the essence, particularly if there's a reliability need that's been addressed by any upgrade."

SPP's tariff defines STRPs as upgrades that meet the criteria for competitive projects but are needed in three years or less to address "identified reliability violations." In that case, STRPs are not considered competitive upgrades under the tariff and are awarded to the incumbent transmission owner.

SPC Increases Membership

The Corporate Governance Committee has approved 11 nominations to the SPC, raising the committee's sector membership to match that of the 23-person Members Committee. The nominations result from an April change to the bylaws. The SPP board will vote on the nominations during its August meeting.

The new members are:

Nick Abraham, ITC Great Plains; Rebecca Atkins, Missouri Joint Municipal EUC; Jarred Cooley, SPS/Xcel Energy; Mark Foreman, Tenaska Power Services; Steve Gaw, Advanced Power Alliance; Christopher Matos, Google; Kevin Noblet, Kansas Electric Power Cooperative; Robert Pick, Nebraska Public Power District; Sarah Ruen, Tri-State Generation & Transmission; Emily Shuart, OG&E; Christy Walsh, Natural Resources Defense Council.

SPP has since announced Shuart will be joining SPP in September as senior director of external affairs and stakeholder relations. (See *SPP Adds OG&E's Shuart to External Affairs Leadership*.) ■

— Tom Kleckner

EEI: Electric Companies Invested $178B in 2024

Planned Capital Spending Through 2029 Estimated at over $1.1T

By John Cropley

U.S. investor-owned electric companies invested $178 billion in 2024 and are projected to invest more than $1.1 trillion through 2029, their trade organization reported.

The Edison Electric Institute said July 23 in its annual *Financial Review* that this level of capital expenditure exceeds every other U.S. business sector and places electric companies at the forefront of a transformational time for the economy.

2024 was the 13th straight record-setting year for investment, EEI said. In just the past decade, annual capital outlay has jumped from $104 billion to $178.2 billion. The largest single jump was from $147.7 billion in 2022 to $168 billion in 2023.

The 2024 financials indicate the scale of the industry. The report shows that collectively, U.S. investor-owned electric companies had:

- $403.5 billion in 2024 operating income, down 0.1% from 2023;
- $54.6 billion in net income, up 4.5%;
- $34 billion in dividends paid on common stock, up 5.8%;
- $1.57 trillion in property, facilities and equipment, up 5.5 %; and
- $2.18 trillion in total assets, up 5.1%.

The industry's average credit rating remained at BBB+ for the 11th year in a row, EIA said, and 94% of EEI Index companies increased their dividend. At 62.2%, the dividend payout ratio is the highest of any U.S. business sector, EEI said.

On the regulatory front, 81 rate reviews were filed in 2024 and 78 decided; average awarded return on equity was 9.73%, up from 9.58% a year earlier. The 2024 ROE broke down to 9.84% for vertically integrated companies and 9.53% for distribution-only companies.

The data covers 38 investor-owned electric companies whose stock is publicly traded on major U.S. stock exchanges, plus five companies that provide regulated electric service in the United States but are not listed on the U.S. exchanges.

Why This Matters

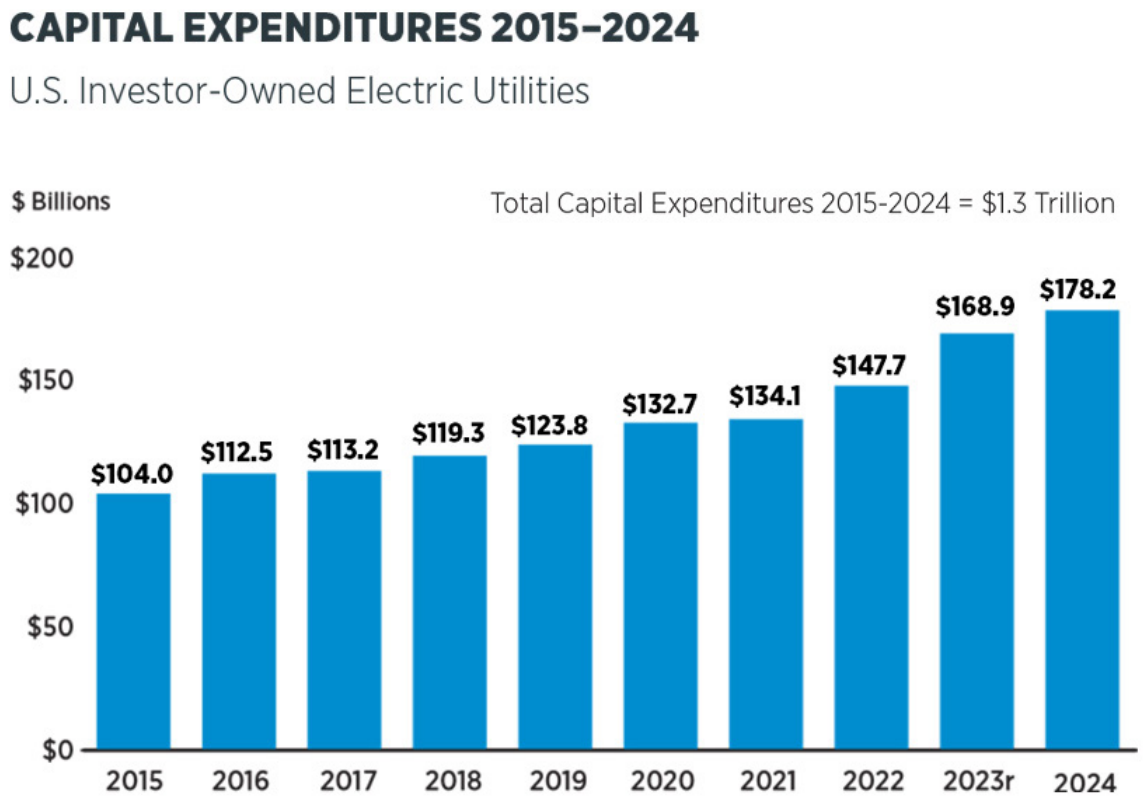
The data gives scale to the U.S. electric industry, and to the massive capital outlay it plans.

Stock prices for the 38 EEI Index companies ended 2024 19.1% higher, placing them well ahead of the Dow Jones Industrial Average, well short of the S&P 500, and far short of the Nasdaq. Interest rate changes in the fourth quarter stunted the EEI Index's full-year performance.

The index companies had a combined $1.02 trillion market capitalization at the end of 2024, with NextEra Energy the leader at $147.2 billion, Southern Co. a distant second at $90.3 billion and Unitil bringing up the rear at $900 million.

In a news release, EEI President Drew Maloney looked beyond the numbers to the significance of the financials: "America's electric companies are leading in this unique and critical moment for our nation. As demand for electricity continues to grow, we remain committed to making the investments needed to strengthen America's energy security while ensuring that our customers receive reliable, affordable energy."

EEI said these companies support more than 7 million jobs nationwide and account for 5% of the U.S. GDP. ■



The Edison Electric Institute's 2024 Financial Review shows a steadily rising level of investment by U.S. investor-owned electric companies. | *EEI*

NextEra Energy Puts Brave Face on Renewables' Prospects

CEO Says Company Positioned to Navigate New Federal Challenges

By John Cropley

The nation's largest renewable energy developer continues to present renewables as a bridge to the grid of the future and fashion itself as an "all-of-the-above" company in an optimal position to build that bridge.

But NextEra Energy's *July 23 financial report* came on the heels of potentially major roadblocks for wind and solar development being erected by the federal government.

The company's stock price took a hit in trading later in the day, despite solid second-quarter financials with year-over-year growth in revenue, earnings and order backlog.

Component company NextEra Energy Resources added more than 1 GW of commitments from hyperscalers to its backlog during the quarter, raising its total existing and planned service for data center and technology customers to more than 10.5 GW.

Its overall backlog is nearly 30 GW, the majority of it wind and solar generation, which is in a race to start or finish construction in time to qualify for sunsetting federal tax credits.

Tariffs, executive orders and agency rulemaking add uncertainty to the company's strategizing, NextEra CEO John Ketchum said during a *conference call* with financial analysts.

"While there are risks to be managed, we believe there also are significant opportunities, given the steps we've taken to prepare for this moment, as we expect a natural pull forward of demand," he said. "We are in a constant state of construction."

Work in progress at FPL's Sunshine Gateway Solar Energy Center in Columbia County, Fla. | *NextEra Energy*

No company is immune to all risks, Ketchum said, but NextEra has proved repeatedly it can navigate challenges.

He repeated a variation of the message that the renewables sector began broadcasting the day after Election Day 2024: America needs us.

That message seems not to have resonated with enough decision makers, given the details of the One Big Beautiful Bill Act that target wind and solar development.

But the company views OBBBA as a rule change, not a sunset or a cliff. "Tough, but constructive," Ketchum called it.

"We are firmly aligned with the administration's goal to unleash American energy dominance, and to do so, we need all of the electrons we can get on the grid. There's truly no time to wait," Ketchum said.

"As I've said many times, we're going to need all forms of energy to meet this moment. New gas and nuclear are on the way and will be critical to meeting demand over the long term. Renewables and storage can bridge the gap and will play an important role in an all-of-the-above future."

Ketchum said the leadership believes NextEra has begun construction of enough projects to reach its development expectations through 2029. They cannot, however, make any guarantees.

He added that if smaller companies not as well prepared as NextEra are unable to move forward in this environment, there would be opportunity for NextEra to pick up their projects and move them to completion.

Turning to the Duane Arnold nuclear plant in Iowa, Ketchum said engineering studies and site reviews are progressing favorably, and there are conversations with customers about offtake of the power it would produce if restarted.

NextEra reported second-quarter 2025 earnings per share of $1.05 on revenue of $6.7 billion and net income of $2.03 billion, up from 96 cents, $6.07 billion and $1.62 billion in the same period of 2024.

Its stock price dropped 6.1% in trading July 23 to close at $72.82, near the middle of its 52-week range. ■

Why This Matters

NextEra says it is ready to weather the oppositional new federal policies facing one of its core businesses.

GE Vernova's Gas Power Equipment Surge Continues

Company Expects Sustained Demand amid Federal Policy Shifts

By John Cropley

GE Vernova's gas power and electrification businesses continue to surge amid growing power demand.

The company on July 23 *reported second-quarter financials* that exceeded projections and offered an optimistic message that sent its stock price soaring to all-time highs.

CEO Scott Strazik said GE Vernova's backlog for gas-fired turbines grew from 50 GW of orders and manufacturing slot reservations to 55 GW in the second quarter, and he expects to end the year at 60 GW. The longer-term expectation is 80 to 100 GW of backlog.

The company's large heavy-duty gas turbines are in high demand, but there also is growing demand for its small aeroderivative gas turbine packages that leave the factory 95% preassembled.

Just a day earlier, *GE announced it would sell* 29 of these smaller units rated at 34 MW each — nearly 1 GW in total — to Crusoe for its AI data centers.

This technology — essentially a modified jet engine with emissions controls — is quick to deploy, quick to start up and can provide a bridge solution when the interconnection queue is moving more slowly than the customer wants to. Eventually, the aeroderivative turbines can become backup power sources for a facility or connect to the grid, Strazik said.

GE Vernova also has its name on a massive installed generation fleet built by General Electric and is seeing strong growth in its service business, Strazik said.

"Our services backlog also grew approximately $1 billion in the second quarter," he said. The company has been incrementally increasing its pricing on new equipment orders and will be doing so with its service business.

During an earnings call July 23, an analyst asked what effect sharp changes in federal energy policy are having on GE Vernova.

The reconciliation bill was finalized only a few weeks ago, Strazik said, so it is early to draw conclusions. However, GE Vernova has seen accelerated interest — but not yet orders — for grid equipment supporting wind and solar generation, he said. That is near- to mid-term interest, he said, which would match with the impending end of federal tax credits for wind and solar energy development.

"There also is very clear market sentiment that into the next decade, there's going to be a need for more gas," Strazik said. "I would say our pipeline of activity for gas demand is only growing, but it's growing at even more healthy levels for '29 deliveries, '30, '31 — periods of time where, maybe prior to the bill being signed, some of our traditional customers may have been intending more wind or solar."

GE Vernova's second-quarter results surpassed projections, pushing first-half 2025 revenue, earnings, free cash flow and backlog higher than year-ago levels. The company has increased its projections for the second half of 2025.

The price of GEV stock soared throughout the trading day, closing 14.6% higher than July 22 and 349.3% higher than on the close of its first day of trading in April 2024.

Also with its second-quarter financial results, GE said:

- Steam power service orders jumped on efforts to upgrade existing nuclear reactors and extend their operation.
- Even larger growth was seen in hydropower, again because of upgrades.
- Progress continues on development of the 300-MW small modular reactor that is the first SMR being built in North America; more customer announcements are expected in the second half.
- Demand for synchronous condensers, a longstanding but minor line for the company, is expected to grow with the need for grid-stabilizing technology, Strazik said. "We see this as a credible $5 billion market opportunity a year."
- Onshore orders in North America drove an increase in revenue for the wind business, offset by continued losses offshore; it may approach the breakeven point in the second half.
- The electrification business saw a $2 billion increase in backlog, driven by switchgear and transformers. ■

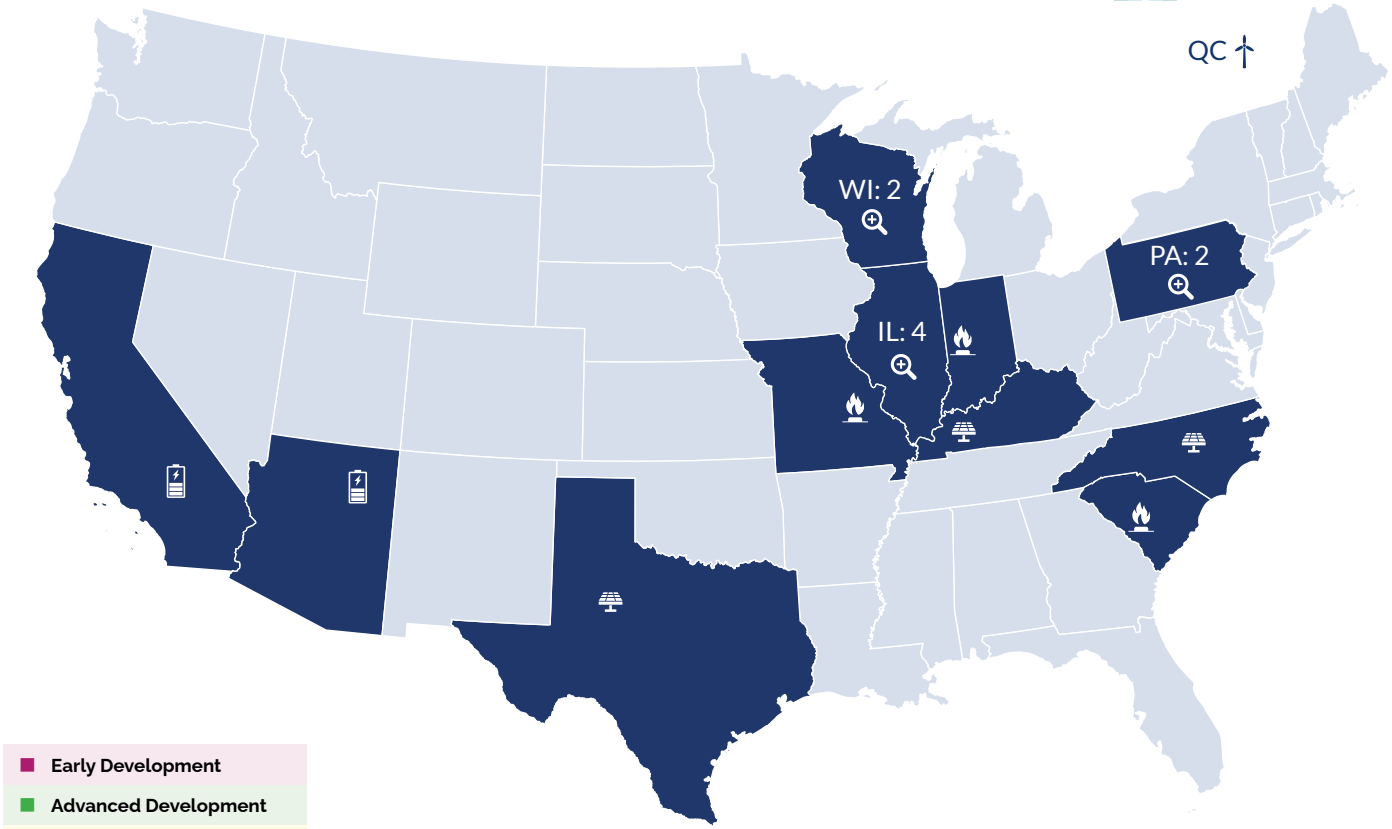
Why This Matters

The company is a major supplier of power equipment, and its order book can provide a preview of trends within the sector.

An employee moves a circuit breaker manufactured at GE Vernova's Grid Solutions facility in Charleroi, Pa. | *GE Vernova*

Generation Projects Added in the Past Week

YES ENERGY



- Early Development
- Advanced Development
- Under Construction

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
Painted Desert Solar BESS	AES Corp.	Energy Storage	AZ		2100
Key Storage C	NextEra Energy, Inc.	Energy Storage	CA	35	2027
Hawk-Attollo Solar	Ownership Undisclosed	Solar	IL	4	2100
Camp Creek Solar 2	Ownership Undisclosed	Solar	IL	5	2028
Dundas Solar 1	Ownership Undisclosed	Solar	IL	5	2033
Dundas Solar 2 & 3	Ownership Undisclosed	Solar	IL	8	2028
Cayuga Combined Cycle CC2	Duke Energy	Natural Gas	IN	738	2030
Paradise Solar	Edelen Renewables	Solar	KY	63	2100
Big Hollow Energy Center Natural Gas Plant	Ameren	Natural Gas	MO	800	2028
Ironbound Solar	Headwater Energy	Solar	NC	40	2026
Shippingport Power Station Phase I	The Frontier Group of Companies (FGC)	Natural Gas	PA	900	2026
Shippingport Power Station Phase II	The Frontier Group of Companies (FGC)	Natural Gas	PA	2,700	2029
Hydro-Quebec Nutinamu-Chauvin Wind Project	Hydro-Québec	Wind	Quebec	1,000	2100
Urquhart Power Station Expansion	Dominion Energy	Natural Gas	SC	200	2028
Maldives Solar (New)	NextEra Energy, Inc.	Solar	TX	184	2028
Foundry Ridge Energy Center	Invenergy	Natural Gas	WI	324	2028
Columbia Wind	Alliant Energy	Wind	WI	281	2028

Company Briefs

Amazon Pulls Virginia Data Center Proposal After Resistance

Amazon Web Services last week pulled an application for a 7.2 million-square-foot data center in Louisa County following a surge of resident opposition.

AWS' proposed third data center would have been one of the largest in the area by far. The 1,370-acre plot prompted concerns about construction near schools and how much water would be needed to cool the systems inside the building. After the latest application was filed, community members took to social media and local meetings to share worries and debate over possible sound pollution, loss of agricultural land and the rapid rate of development.

The letter from an AWS attorney didn't specify if the company would come back with a future application.

More: *Virginia Mercury*

Estuary Turns on Solar-plus-storage Project to Power Vegas Casinos

Estuary Power last week announced it has commenced operations of its 185-MW solar, 400-MW battery energy storage system project in Lincoln County, Nev.

The first phase of the Escape project, with 70 MW of solar capacity, began supplying power to Caesars Entertainment and Wynn Las Vegas. The second phase, consisting of 115 MW of solar and 400 MW of battery capacity, will begin supplying MGM Resorts International's hotel and casino resort later this year.

More: *Energy Storage News*

Enbridge to Invest $900M in Texas Solar Project

Enbridge last week announced it had reached a decision to invest $900 million on a 600-MW solar power project in Texas.

Meta Platforms has signed a long-term contract to purchase 100% of the project's output to help power its regional operations.

The Clear Fork project, located near San Antonio, is expected to become operational by 2027.

More: *Reuters*

Federal Briefs

Utilities to Invest $1T by 2030 to Meet Demand

Investor-owned utilities are projected to invest more than $1.1 trillion between 2025-2029 to meet growing demand, according to a report released from the Edison Electric Institute.

A majority of the investments are intended to meet rising data center demand, which is expected to rise about 20% annually from 2023 to 2030 to as much as 220 GW.

The sector brought 52 GW of new generating online in 2024, which was more than the 46.8 GW in 2023 and the 35.1 GW in 2022, according to the report.

More: *EEI*

NOAA Places 2 High-ranking Officials on Leave

The Trump administration last week placed two high-ranking officials at the National Oceanic and Atmospheric Administration on leave amid efforts to make cuts at the agency.

Deputy General Counsel Jeff Dillen and Stephen Volz, acting assistant secretary and assistant administrator for NOAA's Satellite and Information Service, were placed on administrative leave, spokesperson Kim Doster confirmed. Dillen was placed on leave "pending a review of performance issues over the past several weeks," while Volz was placed on leave "on an unrelated matter."

More: *The Hill*

State Briefs

FLORIDA

PSC Approves Duke Energy's 26.5-mile Tx Line

The Public Service Commission last week approved Duke Energy's proposed 26.5-mile, 230-kV transmission line.

The line will run through Lake, Volusia, Seminole and Orange counties, enhancing system reliability and increasing power transfer capabilities, according to the company.

The line is projected to cost $165 million and be in service by January 2030.

More: *WFTV*

IDAHO

State Pauses Work on Developing Sites for EV Charging Stations

The state has paused all work on the National Electric Vehicle Infrastructure (NEVI) program that was seeking to create a connected network of electric vehicle charging stations along every

50 miles of interstate highway, Office of Energy and Mineral Resources Administrator Cally Younger said.

The pause was implemented nearly six months ago after state transportation officials received a letter from the Federal Highway Administration. The letter informed officials that the new leadership of the Department of Transportation had rescinded all previous guidance for the program and was immediately suspending the approval of all state EV infrastructure development plans.

The state was set to receive about $29 million over five years for creating a network of connected EV charging stations.

More: *Idaho Capital Sun*

ILLINOIS

Pramaggiore Sentenced to 2 Years for Bribery Scheme

Former Commonwealth Edison CEO **Anne Pramaggiore** was sentenced to two years in prison for her role in a yearslong bribery scheme meant to influence ex-House Speaker Michael Madigan.

U.S. District Judge Manish Shah tossed most of the bribery counts earlier this year and based Pramaggiore's sentence and $750,000 fine only on guilty verdicts for cooking ComEd's books to mask the payments and an overarching conspiracy charge.

Pramaggiore is scheduled to report to prison Dec. 1 but vowed to appeal the verdict and the sentence.

More: *Capitol News Illinois*

KENTUCKY

DOE Selects Paducah for Future Energy, AI Infrastructure Site

The U.S. Department of Energy last week named Paducah's Gaseous Diffusion Plant as one of four federally owned sites selected for potential AI data center development and the clean energy infrastructure needed to power it.

According to DOE, the site is one of the nation's largest former uranium enrichment facilities and is undergoing extensive preparation for future redevelopment.

More: *Northern Kentucky Tribune*

NEW YORK

Federal Court Upholds State Gas Ban

The U.S. District Court for Northern New York last week upheld the state's "gas ban" legislation.

The plaintiffs' coalition, including the Nation Association of Home Builders and the New York State Builders Association, filed a complaint in October 2023 arguing the state's legislation is pre-empted by the Energy Policy and Conservation Act, which prevents state and local governments from setting their own standards concerning energy efficiency or energy use of appliances. However, the court ruled the state's prohibition on the installation of fossil-fuel equipment does not concern the "energy use" of covered products as defined by the act and is therefore not preempted.

More: *National Association of Home Builders*

Syracuse Municipal GHG Emissions Down 67% Since 2010

A new report found the city of Syracuse's municipal operations reduced their greenhouse gas emissions by 67% and the overall community posted an emissions reduction of 29%, both when compared to 2010 emissions.

The city's conversion to LED streetlights and traffic signals, implementation of a refrigerant management system, procurement of fuel-efficient vehicles, optimization of waste-collection routes and expansion of the urban forestry program all "played a role" in the reductions.

The findings from the 2010 Greenhouse Gas Emission Inventory provided information the city needed to set emissions-reduction targets of 40% for municipal operations and 7% for the community by 2020.

More: *Central New York Business Journal*

NORTH CAROLINA

Duke Energy Seeks Approval for Natural Gas Project

Duke Energy last week notified the Utilities Commission that it will be requesting permission to build two natural gas-powered combustion turbines at the former Buck Steam Station site.

The former coal plant is on Duke Energy-owned land. The new turbines, which would generate 850 MW, would be near the utility's existing 718-MW natural gas-fired combined-cycle plant.

Duke must now wait at least 120 days to submit a formal application for a certificate of public convenience and necessity.

More: *The Charlotte Observer*

RHODE ISLAND

Rhode Island Energy Proposes Lower Winter Rates

Rhode Island Energy last week proposed lower electricity prices for the upcoming winter season compared to last year's rates.

The utility said the new rate, covering Oct. 1 to March 31, would be 14.77 cents/kWh, about 9% lower than last winter.

The company also said it's pursuing additional steps to help customers. One proposal under review would credit electric customers $20–$30 per month and gas customers $40 to $50 per month during January, February and March of 2026 and 2027.

More: *WPRI*