ISSN 2377-8016 : Volume 2025/Issue 18 ▪ May 6, 2025

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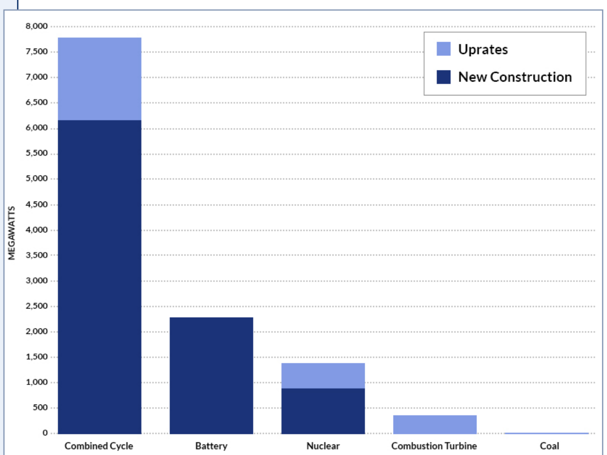
PJM FERC/FEDERAL

PJM Selects 51 Projects for Expedited Interconnection Studies



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PJM's Reliability Resource Initiative is meant to address a possible capacity shortfall in the 2029/30 delivery year by expediting interconnection studies on 51 projects that can rapidly add capacity to the grid.

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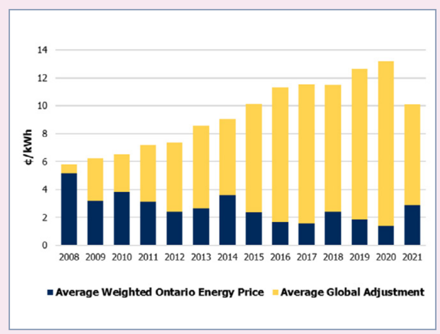

IESO

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RTO Insider
2415 Boston St.
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(301) 658-6885

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In this week's issue

Nobody Does Capacity Quite Like Ontario

Call It Whatever You Want, but Don't Call It 'Deregulated'

By Peter Kelly-Detwiler

Peter Kelly-Detwiler

Twenty-two years after it went live, Ontario's independent electric system operator, IESO, has launched its Market Renewal Program (MRP), instituting a nodal day-ahead market that covers more than 900 locations.

The revision appears to have *gone smoothly*, with the grid operator now joining the seven U.S. ISOs and RTOs that have day-ahead structures. Given that fact, it's an opportune time to look at the bigger picture of Ontario's structure and competitive electricity markets in general.

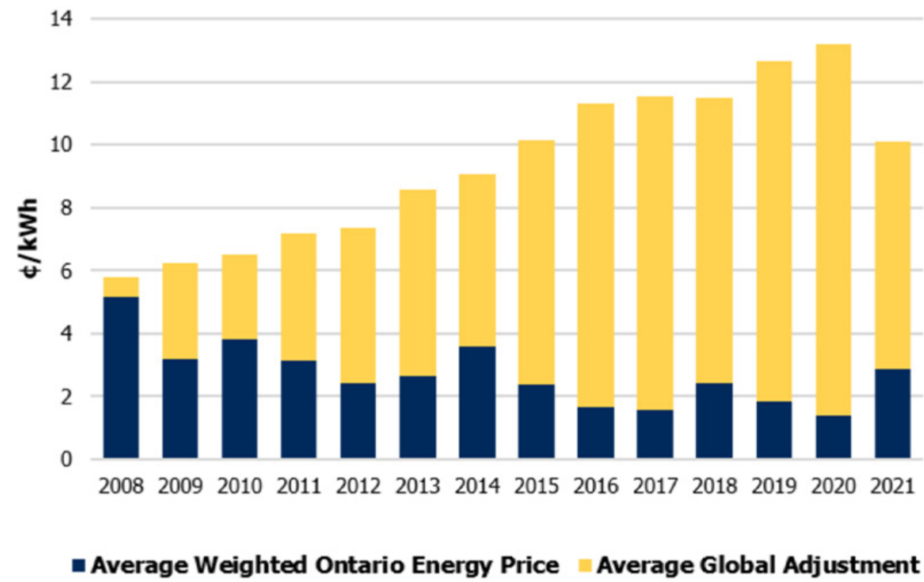
DA markets typically are where the largest volumes of electricity are transacted on a location-specific nodal basis, with varying levels of nodal granularity. Under its earlier approach, IESO had operated only a real-time market with a single price, irrespective of location or transmission constraints.

Generators could schedule their output the day prior, but commitments were not financially binding. Any inefficiencies or price discrepancies, including congestion, were settled through compensatory out-of-market payments, and discrepancies between expected generation and actual real time operations were not subject to penalty.

Under the new MRP, day-ahead market offers — which create financial obligations to deliver energy the following day — will be scheduled to match forecast demands. Prices will be bound by a floor of -$100/MWh and a ceiling of $2,000/MWh.

Why This Matters

Only time will tell whether capacity costs will decline as a total percentage of the entire wholesale bill. But if the history of many other grid operators is any guide, the rules-tweaking is far from over.



Ontario lacks a capacity market, choosing instead the Global Adjustment Charge to address generators' "missing money" shortfalls from energy market revenues. There is typically a strong inverse relationship between wholesale electric prices (the Ontario Energy Price) and the GAC. | *IESO*

In some ways, it's surprising the move took so long. Locational day-ahead markets create more market efficiency while also offering grid operators and market participants better foresight into what will happen the following day. They are more deliberately proactive and less reactive to real-time events.

The move was a big step for IESO and one of the biggest tweaks to its market design in years. And while it increases the overlap in the Venn diagram with other market operators, IESO's action and market redesign highlights a very curious fact about North America's restructured markets: Each "deregulated" market embraces the overriding concept of competition but then spikes the drink with its own highly local flavors.

Editorial pet peeve: It's not clear why people insist on calling this "deregulation." With highly complex competitive markets superimposed on regulatory supervision for distribution at the state or provincial level, there are far more — and more complex — rules than ever existed before the advent of competition. And operators keep tweaking them to respond to the latest perceived market shortcoming.

These market flavors also defy any attempt by generators, battery operators or demand response aggregators to achieve economies of scale — no, we have created a true Tower of Babel here.

To illustrate the nature of this multifaceted hydra, let's take the issue of capacity in a number of markets. Texas has no capacity market, letting energy scarcity prices offer the signals, although operating reserves are in the mix as well. Meanwhile, ISO-NE and PJM hold formal capacity market (FCM) auctions three years in advance — unless the regulatory conversation gets so muddled that they get delayed for years, *as has been the case for PJM*.

New York *long ago decided* the FCM approach was too potentially inefficient and risky, and opted for monthly options with the possibility of transacting seasonal strips. Meanwhile, on the West Coast, California's ISO tasks the utilities with procuring capacity resources.

In many markets, capacity represents a noticeable element on the wholesale power bill. Exhibit A is PJM, with its recent eye-watering 2025/26 auction results at *just under $270/MW-day*, and the just-formalized *floor and ceiling prices of $175 to $325/MW-day* for the coming two auctions. Exhibit B is *MISO's just released auction results* for this summer, coming in devilishly high at just over $666/MW-day and annually between $212 and $217/MW-day. They make PJM look tame by comparison.

But nobody does capacity quite like Ontario, and that hasn't changed with its Market Renewal.

Capacity and the Global Adjustment Charge (GAC)

As in other markets with capacity prices, the GAC — established in 2006 — is *intended to cover the cost* of building and maintaining supply infrastructure to ensure system resource adequacy. The initial MRP proposal intended to do away with the GAC and replace it with a formal capacity auction. However, pushback from various stakeholders resulted in this plan being abandoned.

Unlike the role of capacity pricing in other markets, though, the GAC specifically addresses the difference between the total compensation made to certain contracted generators and any offsetting market revenues. As such, there typically has been a *strong inverse relationship between wholesale electric energy prices and the GAC*. When wholesale energy prices are lower, the GAC is higher, and vice versa. And energy prices historically have been very low, with the result that the GAC typically is the largest single element on the average consumer's total wholesale power bill, often representing *up to 65% or more of the monthly costs*.

Ontario's GAC will continue under the new program, but its impact and interaction will change slightly. The greatest impact may simply be that it will reflect greater location-specific volatility resulting from a nodal pricing program that specifically integrates the impact of congestion.

Lower hourly energy prices will result in higher compensatory GACs, and higher prices will result in the opposite. Only time will tell whether capacity costs will decline as a total percentage of the entire wholesale bill. But if the history of many other grid operators is any guide, the rules-tweaking is far from over. Call it whatever you want, but don't call it "deregulated." ■

Around the Corner columnist Peter Kelly-Detwiler of NorthBridge Energy Partners is an industry expert in the complex interaction between power markets and evolving technologies on both sides of the meter.

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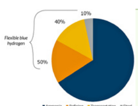

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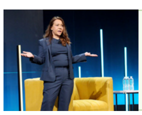

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FERC Approves $180M Annually for RMR Deals with Brandon Shores and Wagner Plants

By James Downing

FERC issued an order approving settlements on reliability-must-run (RMR) deals that will keep the Brandon Shores Generating Station and the H.A. Wagner Generating Station in Maryland running until May 31, 2029 (*ER24-1787 and ER24-1790*).

Talen Energy owns both plants, which are near Baltimore and had sought to retire this year. But PJM found that would have led to reliability issues. Brandon Shores is a 1,289-MW coal plant, and Wagner is an 843-MW oil-fired unit. Now they will run until transmission improvements are ready to replace them reliably.

Brandon Shores is getting $145 million a year and Wagner $35 million, which includes fixed-cost charges, a monthly investment tracker payment to recover spending that's needed to keep the plants running and a reimbursement mechanism to cover operations and maintenance costs.

Talen entered into settlements with Exelon, PJM, the Maryland Public Service Commission, the Southern Maryland Electric Cooperative and the Old Dominion Electric Cooperative on the RMR deals, which cut its initial annual cost from $175 million for Brandon Shores and $40 million for Wagner. Talen will credit market revenues the plants earn back to customers, and it agreed to limits on investments in the plants, which require PJM approval.

PJM said the settlements represent a significant achievement of consensus on issues between Talen and a broad coalition of load parties that will pay for the RMR deals.

The deal was opposed by PJM's Independent Market Monitor and the Maryland Office of People's Counsel, who took issue with how the plants determined their sunk costs. Talen was spun off from PPL in 2015, and at that point Brandon Shores was appraised at $648 million.

The Brandon Shores coal-fired power plant | *Talen Energy*

Why This Matters

The RMR agreements with the plants will help preserve reliability in the Baltimore area while grid upgrades are finished so they can reliably shut down.

But in 2012, the firm bought both plants for just $372.5 million. The people's counsel argued that using the higher number amounted to a windfall for Talen.

FERC trial staff countered that the sunk costs are within the just and reasonable range and will be offset by capacity revenues being credited back to customers. And costs would be greater if outages occurred in the area because the plants were retired too soon.

"Under this approach, the commission need not find that the rate is exactly the rate the commission would establish on the merits after litigation," the order said. "The commission need only find that the overall package, resulting from the give and take of the bargaining which led to the settlement, falls within a broad ambit of various rates which may be just and reasonable."

Precedent gives the commission a few legal rationales for approving settlements. The one it picked focuses on the end result of the deal and involves a balancing of the benefits with costs and the potential effect of continued litigation.

The deals provide a high degree of certainty to market participants that the units will be available, including a longer RMR (five months more than initially proposed) and fewer circumstances under which Wagner and Brandon Shores can terminate operations. It also gives PJM flexibility to end the RMR deals early if market conditions change.

"This certainty provides value to the settlements, especially in light of the serious reliability concerns at stake without the settlements that could lead to much greater costs overall," FERC said. ■

House Committee Weighs Bill to Let Dispatchable Resources Jump Queue

Skeptics Contend H.R. 1407 Overlooks Other Factors Needed for Interconnection

By Elaine Goodman

Why This Matters

The GRID Power Act's goal of allowing dispatchable resources to jump ahead in the interconnection queue could run counter to some states' plans to prioritize increased adoption of variable renewable resources.

A bill that would allow dispatchable energy projects to jump ahead in the interconnection queue under certain circumstances sparked debate during a House Energy and Commerce Subcommittee on Energy hearing April 30.

Subcommittee members grilled two panels of experts during the hearing to gather information related to 14 energy-related bills. One of those was H.R. 1047, the Guaranteeing Reliability through the Interconnection of Dispatchable (GRID) Power Act, introduced by Rep. Troy Balderson (R-Ohio) in February. (See *Bills Introduced in Congress to Speed up Queues for Dispatchable Power Plants*.)

The bill would direct FERC to launch a rulemaking that would allow transmission providers to file requests to move their dispatchable power projects up in the interconnection queue. Applicants would be required to show why the prioritization was needed and how it would improve grid reliance or resilience. Transmission providers also would need to conduct a stakeholder engagement and public comment process before submitting the applications.

FERC then would be required to issue a decision within 60 days.

Todd Snitchler, CEO of the Electric Power Supply Association, described the provisions of the GRID Power Act as "an emergency relief valve." EPSA has endorsed the legislation.

"What it seeks to do … is a very balanced approach to try and address a critical issue in a way that does not immediately advance any one project to the front of the line and in fact takes a measured approach to try and ensure reliability over time," Snitchler said in response to questioning from Balderson.

Snitchler compared the bill to PJM's Reliability Resource Initiative (RRI) that FERC approved in February. PJM described the initiative as a way to get shovel-ready projects connected faster by adding them to the final transition cycle of its reformed interconnection process, rather than waiting for the new cycle to be implemented next year. (See *FERC Approves PJM's One-time Fast-track Interconnection Process*.)

"This has a very similar flavor in trying to address the occasions as they arise in a way that will allow the emergency to be relieved, and then go back to business as usual," Snitchler said.

The GRID Power Act defines dispatchable power as "an electric energy generation resource capable of providing known and forecastable electric supply in time intervals necessary to ensure grid reliability."

Some lawmakers, including Rep. Jake Auchincloss (D-Mass.), said that instead of focusing solely on dispatchability, "the first [project] to get connected should be the first that's ready."

Rep. Troy Balderson (R-Ohio) questions witnesses about the GRID Power Act during a hearing of the House Energy and Commerce Subcommittee on Energy. | *House Energy and Commerce Committee*

Rep. Robert Menendez (D-N.J.) said natural gas power plants may face lengthy delays in receiving new turbines.

"We want to get projects on the grid. The interconnection process is absolutely a part of that," Menendez said. "But getting projects on the grid also includes financing, local permitting and supply chain issues that all must be addressed as well."

Witness Kim Smaczniak, a partner at energy law firm Roselle LLP, said the GRID Power Act would make it easier to create an interconnection queue that "picks winners and losers among resources." Smaczniak was a special counsel at FERC, where she helped develop the commission's Order 2023 interconnection reforms.

In written comments, Smaczniak said that because of the limited transmission capacity, the bill would increase uncertainty and costs for power projects seeking to connect to the grid.

"Timely, certain, cost-effective interconnection can make or break whether a project is commercially viable," she said.

No action was taken on the GRID Power Act or other legislation during the hearing. Lawmakers have 10 business days to submit additional questions on the bills. ■

Demand Growth and Carbon Targets Prompt New Interest in Nuclear

By James Downing

Duke's Harris nuclear plant outside Raleigh, N.C. | *Duke Energy*

Past talk about a nuclear renaissance has mostly produced aborted projects. But with demand growing and some in the industry still focused on climate change, utilities again are considering the resource for their long-term plans.

After the Fukushima accident in Japan — and the advent of cheap shale gas — the only two nuclear projects to move forward were the Tennessee Valley Authority's Watts Bar Unit 2, completed in 2015, and Southern Co.'s Plant Vogtle Units 3 and 4, completed in 2023 and 2024.

A neighboring utility, Duke Energy, recently submitted a *report* to the North Carolina Utilities Commission outlining what reactors have been developed and built around the world recently, as well as detailing its own plants and where it could build new ones. The firm is not moving ahead with any major investments yet, but its integrated resource plans contemplate adding more than 11,000 MW of new nuclear capacity in the Carolinas by 2050, Duke spokesperson Anne McGovern said.

"The deployment of any new technology will be contingent on ensuring safety, affordability and reliability," McGovern said. "To move forward with a decision on new nuclear generation, we will need to address several key items: the maturity of the technology and the supply chain to support it; cost overrun protection to protect our customers; federal tax credit certainty; and the ability to recover costs on a more timely basis to lower the overall costs of these projects for customers. We will have an opportunity to update state commissions on our progress regarding the potential for future new nuclear investments later this year."

Why This Matters

Duke Energy is among the utilities looking at expanding nuclear in their long-term plans. While the near term is going to be dominated by other generation technologies, nuclear could be a much bigger part of the mix in several decades.

Duke has selected a 1,000-acre site near the Belews Creek Steam Station in North Carolina for a potential advanced nuclear deployment, and it could submit an early site permit application to the Nuclear Regulatory Commission in late 2025. The utility also has kept its combined license from the NRC for its canceled W.S. Lee III plant in Cherokee County, S.C., which gives it the option to build two Westinghouse AP1000 units (the kind used at Vogtle 3 and 4) at the site, McGovern said.

The Lee plant, first proposed in 2007, was part of the last wave of interest in nuclear energy. Around the same time, Progress Energy Carolinas asked the NRC to approve a combined operating license application for additional reactors at the Shearon Harris Nuclear Plant site in North Carolina. Duke merged with Progress several years later, and it has kept the permit request effectively on life support, where it could advance it in the future, according to the report filed with the NCUC.

Even at the Lee site, the report notes, the license would need to be revised to update it for lessons learned from the construction of Vogtle Units 3 and 4.

Plant Vogtle's initial price tag of $14 billion already was high, but the final bill was more than $30 billion, which helped scare other utilities away from building nuclear plants as natural gas and renewables are far cheaper. The experience there has many who watch the industry focused on small modular reactors for the next wave of nuclear development.

"We've seen that it's very expensive right now," Brattle Group Principal Dean Murphy said in an interview. "The promise for SMRs is that they're small enough that we'll be able to build them in a factory and deliver them on a barge or a rail car and install them. And maybe that's true, and maybe that's the pathway to get the cost down by a lot."

In the long term, Murphy is bullish on nuclear energy's future, but he predicted it would take decades for it to ramp up to where it is being installed at scales similar to gas plants, solar or wind today. The next plant built is likely to be expensive, but if it works out, more will follow and costs should drop. That, however, could take until the second half of the century to ramp up in a major way.

Part of the reason Vogtle cost so much was that it was starting construction after a 30-year pause in the U.S., Georgia Public Service Commissioner Tricia Pridemore told the Electric Power Supply Association's Competitive Power Summit in early April.

"Please, can we get more nuclear before that workforce and that supply chain that we struggled and bled for to bring up for Vogtle Units 3 and 4 atrophies?" Pridemore said.

Murphy said the rest of the industry would need to see a new nuclear plant — or two or three — successfully developed and then run for a while before it is confident enough to move ahead with others. That might lead to a second wave that is five times as many as the first small batch.

"Then those are going to have to go pretty well before people jump in and commit on a broad scale," Murphy said. "And that gets you out to sort of midcentury before we're really engaging heavily in building a whole bunch of nuclear."

Vogtle was planned well before artificial intelligence moved from the pages of science fiction novels to the business press, but its completion came just as demand growth started to take off.

Demand growth helps when you are making big, lumpy investments in new generation such as nuclear because it almost always is overbuilt somewhat, Murphy said.

"If demand is growing faster, you're going to catch up much sooner, and you're not hanging out with an excess of capacity for nearly as long," he added.

Both Southern Co. and Duke are vertically integrated firms, which Murphy said could help them in their efforts. A large investment in infrastructure needs some guarantees on its future revenue, and state regulators in those states can push costs, including overruns, through to ratepayers.

"But then, even in a vertically integrated market, regulators might put some limits on how much cost you can pass through, and if you overrun that limit, then that can come back to bite you," Murphy added.

North Carolina also has another key policy Murphy sees as important for nuclear development: a climate law, HB 951, that requires net-zero emissions by midcentury.

"A greater focus on clean energy and climate change could increase the value of nuclear, because it's about the only thing that can provide clean energy and provide firm capacity," Murphy said.

Even states like California and New York could turn to nuclear in the future to meet their midcentury climate targets, which also include meeting new demand from electrifying heating and the growth in electric vehicles, Murphy said. While much of that work can be done with technologies that are cost competitive today, the industry needs some kind of dispatchable, emissions-free resource to get to a 100% clean grid, he said. ■

State Attorneys General Sue Trump for Executive Order Halting Wind Approvals

By James Downing

A group of 18 Democratic state attorneys general filed *suit* May 5 against President Donald Trump's executive order that halted wind energy projects' federal approvals.

The lawsuit, filed in the U.S. District Court for Massachusetts, seeks an injunction against the order so federal agencies can resume working on projects as the litigation is pending. The complainants include states that were banking on major offshore wind projects that have been interrupted, like New Jersey and New York, as well as many that were impacted by the order's impact on onshore wind, such as California and New Mexico.

"This administration is devastating one of our nation's fastest-growing sources of clean, reliable and affordable energy," New York Attorney General Letitia James said in a statement. "This arbitrary and unnecessary directive threatens the loss of thousands of good-paying jobs and billions in investments, and it is delaying our transition away from the fossil fuels that harm our health and our planet."

The order, which Trump issued on the first day of his new term, categorically halted all federal approvals needed for offshore and onshore wind energy, pending an "amorphous" and "extra-statutory" multiagency review of unknown duration. The order cited past, unspecified legal deficiencies and directed relevant federal agencies to stop issuing new or renewed approvals, rights of way, permits, leases or loans for onshore and offshore wind pending the review. (See *Critics Slam Trump's Freeze on New OSW Leases*.)

Why This Matters

The lawsuit may determine whether the president can stop implementation of laws for one targeted energy source, and if the court grants the requested injunction, then such activity could resume shortly.

Agencies have implemented the executive order, with the Department of the Interior even issuing a stop-work order on Empire Wind 1 off New York, which had begun early construction activities. (See *Feds Move to Halt Construction of Empire Wind 1*.)

The federal stoppage has harmed states' efforts to secure reliable, diversified and affordable sources of energy to meet increasing demand, preventing the economic benefits associated with development and the environmental benefits of more clean energy.

"The various actions taken by agency defendants to implement the wind directive are arbitrary and capricious under the Administrative Procedure Act," the lawsuit says. "First, the wind directive was issued with no reasoned explanation for its categorical and indefinite halt of wind energy development. Second, neither the wind directive nor agency defendants have offered any detailed justification to explain the abrupt change in longstanding federal policy supporting the development of wind energy."

Numerous laws require federal agencies to consider and issue decisions on applications for wind energy projects, including the Outer Continental Shelf Lands Act, the Clean Water Act, the Clean Air Act, the National Environmental Policy Act and the Endangered Species Act.

"Under these authorities, agency defendants must comprehensively, but promptly, review, approve, deny or otherwise act on applications to construct and operate wind energy facilities, following specific procedures and standards," the lawsuit says.

Previous presidential administrations, including Trump's first, implemented those laws faithfully and often celebrated the growth in wind energy that resulted. In Trump's first term, seven offshore wind lease auctions were conducted, multiple leases to offshore wind energy developers were issued, and the administration processed environmental reviews of many projects.

Agencies have already looked into wind projects' impact on fisheries, tourism and the environment and found that their impacts were at least acceptable for projects to move forward. Courts have reviewed some of those projects and come down on the side of the agencies.

"The wind directive reverses the robust federal support for wind energy that had spanned decades and multiple administrations, does not account for agency defendants' extensive past federal review of wind development, and conflicts with President Trump and agency defendants' concurrent promotion of domestic energy production, both as a general matter and specifically in several of our states," the lawsuit says.

The order calls on the secretary of the Interior to run the review in consultation with secretaries of the Treasury, Agriculture, Commerce and Energy, and the EPA administrator.

"Despite the extensive past reviews of wind energy projects by agency defendants — indeed, ignoring the existence of these reviews — the directive orders that the assessment consider anew 'the environmental impact of onshore and offshore wind projects upon wildlife' and the 'economic costs associated with the intermittent generation of electricity,'" the complaint says.

The directive was one of several Trump issued on his first day in office this January, which also included one addressing an "energy emergency." (See *Trump Will Need More than Executive Orders for US to Meet Rising Power Demand*.)

Other executive actions since then have emphasized the need for more energy, but the wind order goes against all of them, the lawsuit says.

The order takes a low-cost, clean and abundant energy option off the table at a time when Americans need more affordable electricity, said Environmental Defense Fund Lead Counsel for U.S. Clean Energy Ted Kelly.

"Instead of tapping into America's vast wind resources and growing this industry, the administration is blocking energy progress," Kelly said in a statement. "These attorneys general are right to challenge the Trump administration's illegal attempts to obstruct wind energy." ■

State Officials Discuss Interregional Transmission Plan

By Vincent Gabrielle

Officials from members of the Northeast States Collaborative on Interregional Transmission expounded the group's strategic action plan, released in April.

"There are certain basic truths that apply to transmission planning and development today," Katie Dykes, commissioner of the Connecticut Department of Energy and Environmental Protection, said to an audience of 300 people during a teleconference April 29.

She said the collaborative's nine states — Connecticut, Delaware, Maine, Maryland, Massachusetts, New Jersey, New York, Rhode Island and Vermont — saw a benefit to working together to ease the complications of transmission development as much as possible. "It's imperative that we do so, and we've certainly made a lot of progress over the past two years."

Dykes said numerous studies had found that interregional transmission connections could help stabilize the grid and drive down energy costs. With tariffs and long-term supply chain uncertainties looming, it was more important than ever that states work together to ease the barriers to interregional transmission development as much as they could.

"To achieve this, we need to agree on common standards for transmission technologies so that investment across the system are compatible and consistent," Dykes said, citing the example of an HVDC multi-terminal platform for offshore wind. "Such standardization could lead to more certainty in the supply chain and reduce costs for ratepayers."

The plan, released by the Brattle Group, recommended the states work with the three grid operators in the Northeast to find interregional "low-hanging fruit" that could be developed. (See *Plan Lays out Steps for State-led Interregional Transmission in Northeast*.)

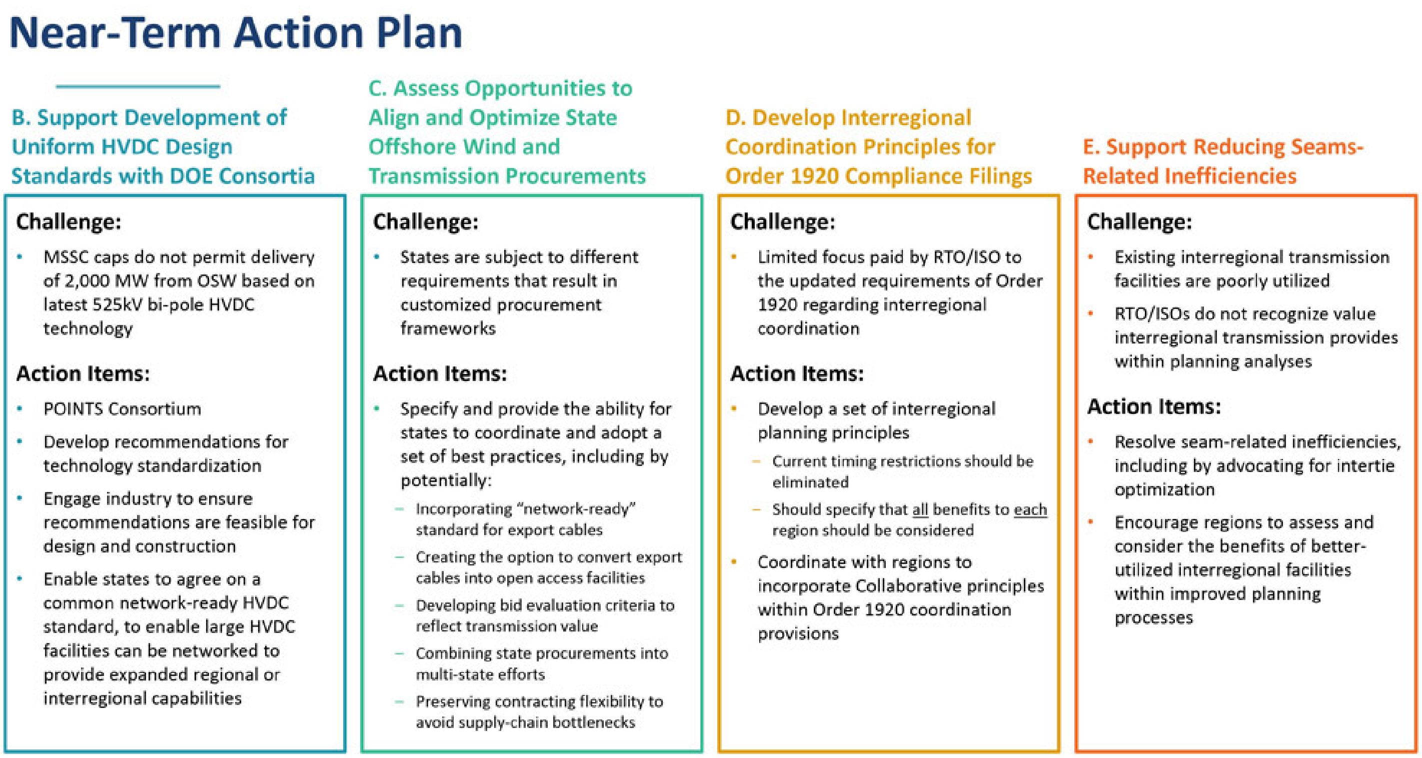
"PJM continues to support working with our neighbors on interregional planning," PJM spokesperson Jeff Shields said in response to *RTO Insider*.

"Transmission planning is an integral part of planning the future power system, as is working collaboratively with the New England states and neighboring regions," ISO-NE spokesperson Randy Burlingame said. He cited ISO-NE's Interregional Planning Stakeholder Advisory Committee and a recent *request for proposals* on interregional transmission. "We look forward to continued collaboration with the states and our counterparts to ensure a reliable grid today and in the future." (See *ISO-NE Releases Longer-term Transmission Planning RFP*.)

NYISO declined to comment.

"No process currently exists for a group of states spanning different transmission planning regions to take the steps necessary to identify, evaluate and ultimately agree to share the cost of beneficial interregional transmission projects," said Joe DeLosa III, a manager and consultant for Brattle.

He presented more *specifics* on the action items outlined by the plan. In the near term, these include working to standardize transmission technology to permit the delivery of 2,000 MW from offshore wind on 525-kV lines, harmonizing state regulations and procurements, and directing the grid operators to implement interregional planning principals in line with FERC Order 1920. They also include reevaluating the benefits that could be provided by the extant interregional connections.



Objectives for the Northeast States Collaborative on Interregional Transmission in the next year | *The Brattle Group*

Over the next few years, the states would expand their efforts via midterm action items, including reevaluating whether tariffs need updating for interregional transmission and exploring the formation of a buying pool for transmission equipment.

A panel of state officials including John Bernecker, director of the Transmission Center of Excellence at the New York State Energy Research and Development Authority; Kira Lawrence, senior policy adviser for the New Jersey Board of Public Utilities; and Jason Marshall, deputy secretary and special counsel in the Massachusetts Executive Office of Energy and Environmental Affairs, addressed questions from spectators. The panel was moderated by Suzanne Glatz, a consultant and former director of interregional planning for PJM.

"One of the critical activities is breaking down silos that have existed within transmission planning, both across the regions but really, across the ways that the benefits of transmission have been assessed," Bernecker said. He said transmission has typically been assessed for market efficiency, reliability or for public policy. "In reality, a given transmission project will have benefits across different areas."


| © RTO Insider

The panel was asked why the plan seemed to have a specific focus on offshore wind given the opposition from the Trump administration.

"While wind power is mentioned, that's more from the perspective of specific technical barriers that need to be addressed in order to fully integrate those resources in the long term," Bernecker said. "But that's not the focus of the plan in its entirety." ■

NWPCC Initial Demand Forecast Sees Sharp Growth for Northwest

Data Centers, EVs to be Biggest Drivers of Increased Electricity Use

By Henrik Nilsson

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Annual energy demand in the Pacific Northwest could reach between 31,000 and 44,000 average megawatts (aMW) by 2046, according to the Northwest Power and Conservation Council's (NWPCC) initial 20-year forecast.

The initial 20-year *demand forecast*, released April 29, does not account for cost-effective efficiency, rooftop solar or demand response that could reduce electricity demand. Council staff intends to release the final forecast by the end of 2026 after deciding how much of those resources they should include, according to a news release.

The council is required under the Northwest Power Act "to develop a plan to ensure an adequate, efficient, economical and reliable power supply for the region." NWPCC publishes a plan every five years, according to the council's website. (See *NWPCC Considers Trump, Data Centers in Regional Power Plan*.)

"Thanks to many months of work by Power Division staff, collaboration with regional partners and our new computer modeling capabilities, we now have a deep understanding of the potential future energy needs of our region," Jennifer Light, power planning director at NWPCC, said in a statement.

"This will help us develop the cost-effective resource strategy that will be robust across future load growth trajectories, while ensuring the Pacific Northwest's power grid continues to be adequate, efficient, economical and reliable over the next two decades," Light added. "We won't take on this task alone. We invite and encourage public participation and collaboration from across the Northwest as we plan for the future of our power system throughout 2025 and 2026."

Why This Matters

The initial forecast comes as the council prepares to release its next power plan, called the Ninth Power Plan, which it is required to publish under the Northwest Power Act.

Since 2010, energy consumption in the Pacific Northwest region has hovered "around 20,000 aMW to 22,000 aMW," Steven Simmons, senior energy forecasting analyst at NWPCC, said during a presentation of the initial forecast.

The region experienced a winter peak of approximately 35,500 MW in February 2025, an increase over the previous winter peak of 35,100 MW in 2023. The region reached a summer peak of 33,300 MW in July 2024, according to the news release.

Demand and peaks are showing no signs of slowing down.

The council tested five scenarios, and energy growth increases under all scenarios, according to the council.

The annual energy demand is projected to reach between 31,000 and 44,000 aMW by 2046, depending on the scenario, and peak demands will range between 47,000 and 60,000 MW, the council stated.

Though there is a mix of winter and summer peaking, historically the Pacific Northwest region is winter peaking.

"However, in our forecast, we're starting to see more summer peaks creep in, for sure, and definitely in some of the specific futures," Simmons said.

But the largest growth is expected from electric vehicles and data centers, according to the forecast.

A major driver of the electric vehicle forecast is transportation policies in Oregon and Washington, said Tomás Morrissey, senior analyst with the council.

"Probably the biggest driver in the model is the 100% new light-duty vehicle standards in Oregon and Washington that stipulate that light-duty vehicles starting in 2035 have to be electric," Morrissey said. "And as you can imagine, that increases load across the system leading into 2035 as sales are ramping up and then continuing past 2035 as the vehicle stock turns over and becomes more and more electrified." ■

California Lawmakers Seek to Trump-proof Pathways Initiative Bill

Proposed Amendments Follow TURN's Opposition to Bill

By Henrik Nilsson

New amendments to California's proposed Pathways bill will include protections against possible attempts by President Donald Trump to influence the state's energy markets, such as pushing it to buy power from coal-fired generators.

Democratic State Sen. Josh Becker presented the proposed amendments during a California Senate Judiciary Committee hearing April 29. The committee unanimously approved all the changes in a late-night vote, sending the bill on to the Appropriations Committee.

The changes follow concerns from consumer advocacy groups like The Utility Reform Network (TURN) that handing over governance of CAISO's energy markets to a proposed independent regional organization (RO) could undermine the Golden State's clean energy goals. (See *California Lawmakers to Discuss Amendment Requests to Pathways Bill*.)

"Some opponents have raised reasonable concerns … and I appreciate those and will continue discussion," Becker said. "I believe the committee amendments not only address these concerns but further strengthen the protections in this bill."

Senate Bill 540, *or Pathways*, is the product of the work of the West-Wide Governance Pathways Initiative, an effort to support the expansion of CAISO's Western Energy Imbalance Market (WEIM) and soon-to-be-implemented Extended Day-Ahead Market (EDAM) to entities outside California by creating a new independent RO to govern rules for CAISO's markets while leaving key elements of the ISO's balancing authority area intact.

Under the bill's first iteration, California could not join the RO market before mid-2027. But with amendments, the timeline would be pushed to January 2028, according to Becker.

This gives stakeholders "a full three years of watching the new administration, seeing what it does and what it attempts to do regarding California's energy markets" before any final decision is made, Becker said.

CAISO headquarters in Folsom, Calif. | © *RTO Insider*

Why This Matters

The amendments seek to assure worried stakeholders that California can move forward with green energy goals under an expanded market.

The amendments also clarify that the RO cannot establish capacity markets. This is to prevent the Trump administration from forcing California to buy coal, Becker said. He added that the strategy to use capacity markets to incentivize coal "is outlined by Project 2025."

"We cannot establish capacity markets under this bill or establish any mandatory reserve or resource adequacy requirements," Becker said.

Additionally, the tariff filed with FERC "cannot assess any cost of fossil fuel generation resources to California participants. E.g. can't force California to pay for coal generated in Wyoming," according to Becker.

Becker also said electrical corporations must leave the RO if one of three things happen: market rules or public policies turn out to be "detrimental to California consumers"; renewable portfolio standards are "held invalid by reviewing court on claims of impermissible discrimination"; or Trump or future presidents use emergency powers to require California to subsidize fossil fuels.

"We now have it in the bill, if any of those things happen, automatic required withdrawal," Becker said.

Other amendments include:

- Require the RO's governing documents and tariff approved by FERC to respect the authority of each state and manage energy markets consistent with existing California protections.
- Allow participants to withdraw without penalties.

• CAISO must provide testimony and receive feedback from the state Senate and Assembly energy committees before adopting the resolution.

• CAISO must conduct a jobs study.

Praise, Concerns, Fear

In calling the amendments "substantial," Becker also said some opponents "are falsely evoking public fear" that the market initiative exposes California to "federal meddling."

"If FERC wants to interfere with our markets today or our climate policies via our energy markets, they can do that today. Just to be extremely clear," Becker said.

Speaking in support of the bill, Marc Joseph, an attorney representing the International Brotherhood of Electrical Workers (IBEW), also noted that Trump already poses a threat to energy markets in the West.

"This bill does not give FERC any more jurisdiction over our policies than it has today," Joseph said. "In any case, as Sen. Becker said, the decision to participate won't come before 2028, so we have plenty of time to evaluate whether this remains a good idea. If it's not, we just don't do it."

Still, former California Public Utilities Commission President Loretta Lynch, an outspoken opponent of SB 540, argued that federal challenges will likely ensue should the bill become law. (See *Calif. Senate Committee Backs Pathways Initiative Bill*.)

"Two major legal concerns that arise from this bill, according to the committee analysis, are based on the federal pre-emption doctrine and the dormant Commerce Clause," Lynch said.

"While the proposed amendments attempt to close the legal deficiencies that make California vulnerable, and I applaud the author for considering proposed amendments, they do not go far enough to protect California," Lynch said. "And most importantly, they change the law now, today, and provide too much of California's current legal authority, giving it over to the FERC and to the new RO."

In an email to *RTO Insider*, Matthew Freedman, staff attorney for TURN, wrote: "TURN appreciates the amendments taken today in the Judiciary Committee to address many of the concerns outlined in our letter. We are continuing to evaluate the bill and are working with Sen. Becker to minimize the risks to California's consumers, environmental protections and clean energy leadership."

Advanced Energy United has supported the bill. In an email, the organization's managing director, Leah Rubin Shen, said, "We are encouraged to see lawmakers engaging constructively and balancing the priorities of a wide range of stakeholder interests."

"This bill will strengthen California and the West's position by building a broader market that protects state interests and fosters regional collaboration," Shen added. ■

CalCCA Study Touts Benefits of RA Trading at Hourly Level

Report Shows $60M in Potential Savings in Summer 2025

By David Krause

The cost of electricity in California could be lowered if energy providers were allowed to trade their resource adequacy products by the hour, a new *study* by the California Community Choice Association (CalCCA) says.

Currently, load-serving entities submit annual and monthly RA reports to the California Public Utilities Commission. In the reports, each LSE must demonstrate that it has procured 90% of its system RA obligation for the five summer months of the coming compliance year and that it meets 90% of its flexible RA obligation for all 12 months. Under existing regulations, California LSEs are limited to trading RA products that cover an entire month.

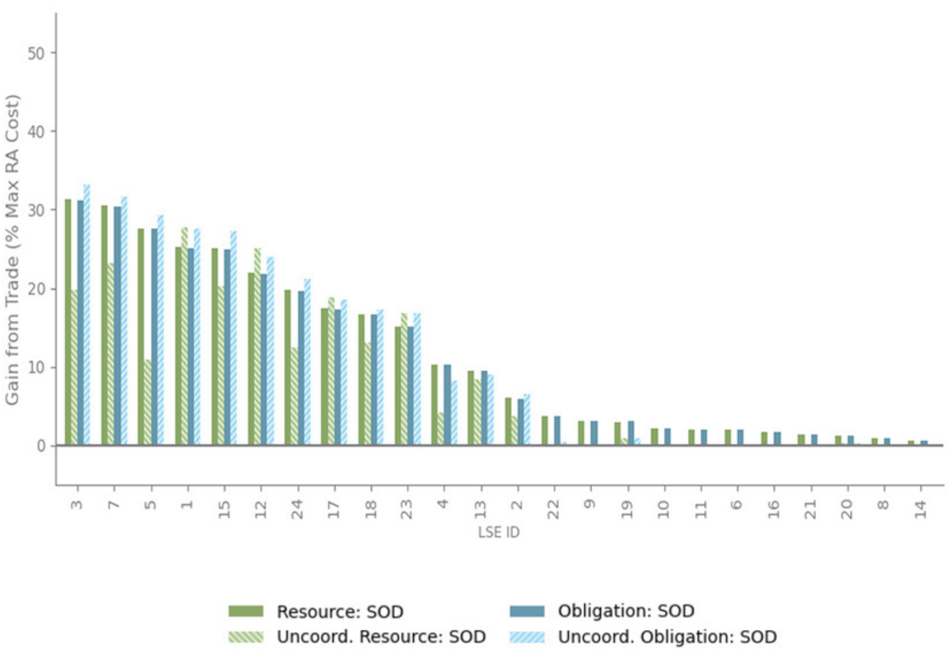
In 2024, CPUC started the first "*Slice of Day*" (SOD) RA program in the U.S. The program requires each LSE to demonstrate sufficient capacity in all 24 hours on CAISO's "worst day" in a month, i.e., the day of the month that has the highest forecast peak load.

However, in the SOD program's first year, many LSEs had more resources than needed, while other LSEs did not have enough, CalCCA's paper says. This outcome "suggests there are additional opportunities for trade that are currently unrealized due to regulatory barriers," it says. It therefore argues for an hourly obligation trading model in order to reduce costs to consumers.

"This is about fairness and common sense," CalCCA CEO Beth Vaughan said in a press release. "Let's stop making energy providers buy more capacity than they need, and let's stop making Californians foot the bill."

CalCAA estimated that average RA prices could decrease by $1/kW-month for every 1-GW demand reduction in the new hourly model. The reduced demand for RA products on the market lowers the price of RA and the cost of meeting RA obligations for all California LSEs.

Reducing the cost of RA in California has grown in importance in recent years following the rapid increase in RA prices, the paper says. For example, the weighted-average RA price was $2.77/kW-month in 2019 but increased by a factor of nine to $26.26/kW-month in 2024, according to the paper.



CCA aggregate direct benefits across May to September 2025. | *CalCAA*

Why This Matters

CalCCA's proposal is aimed at increasing the flexibility of meeting obligations in California's resource adequacy framework, which is unlike any other in the U.S.

Policymakers should support the development of effective trading mechanisms that go hand in hand with the transition to SOD, CalCCA's paper says. Otherwise, the SOD program will drive up costs for consumers with no direct benefit to reliability.

But CalCCA noted that its study is based on simulations and that a "real-world" implementation would require a much more in-depth investigation.

"Implementing an effective trading mechanism with the SOD program will not be easy," the paper says. "Trading in the SOD policy environment is six to nine times more complex than that of the legacy monthly RA product and will require a greater volume of trades, more transactions and more trading partners."

A key principle of CPUC's current RA program is balancing addressing hourly energy sufficiency with advancing California's clean energy, greenhouse gas emissions-reduction and air pollution-reduction goals, spokesperson Terrie Prosper told *RTO Insider*. With increasing penetration of renewable resources, CPUC sought to construct the SOD framework to better manage reliance on use-limited resources in meeting reliability needs, Prosper said.

Trading RA obligations at the hourly level would not influence natural gas generation in California, Prosper said. The RA framework — both the previous structure and the SOD — is a planning construct and does not directly determine how much gas generation will be dispatched in the energy markets. ■

ERCOT's TAC Endorses Congestion Management Plan

By Tom Kleckner

ERCOT stakeholders have endorsed a protocol change (*NPRR1229*) that creates a process to compensate market participants when a constrained management plan or ERCOT-directed switching instruction trips a generator that otherwise would have stayed online.

The revision request passed over objections from consumer groups during the Technical Advisory Committee's April 23 meeting. They said the NPRR shifts costs and deviates from previous market rules for the direct assignment of congestion costs.

"The whole point is that parties are supposed to deal with the direct assignment of congestion costs," said Lyondell Chemical's Eric Schubert, one of the Consumer segment's six members who all voted against the measure. "In other words, you're supposed to have a backstop in case something comes up online, the generator trips. … It seems to us that this is a problematic NPRR and continues down the path of socializing costs that should be directly assigned."

The Lower Colorado River Authority's Blake Holt said the need for compensation will be "extremely rare."

"When a resource is instructed to operate in a risky condition to benefit the grid reliably and is subsequently tripped offline, we believe it is reasonable to cover the cost of the trip," he said. "There's going to be lots of rigor in approving a dispute."

The proposed change passed 20-8, with one abstention. Electric retailers Rhythm Ops and Demand Control 2 joined the Consumer segment in voting against the measure.

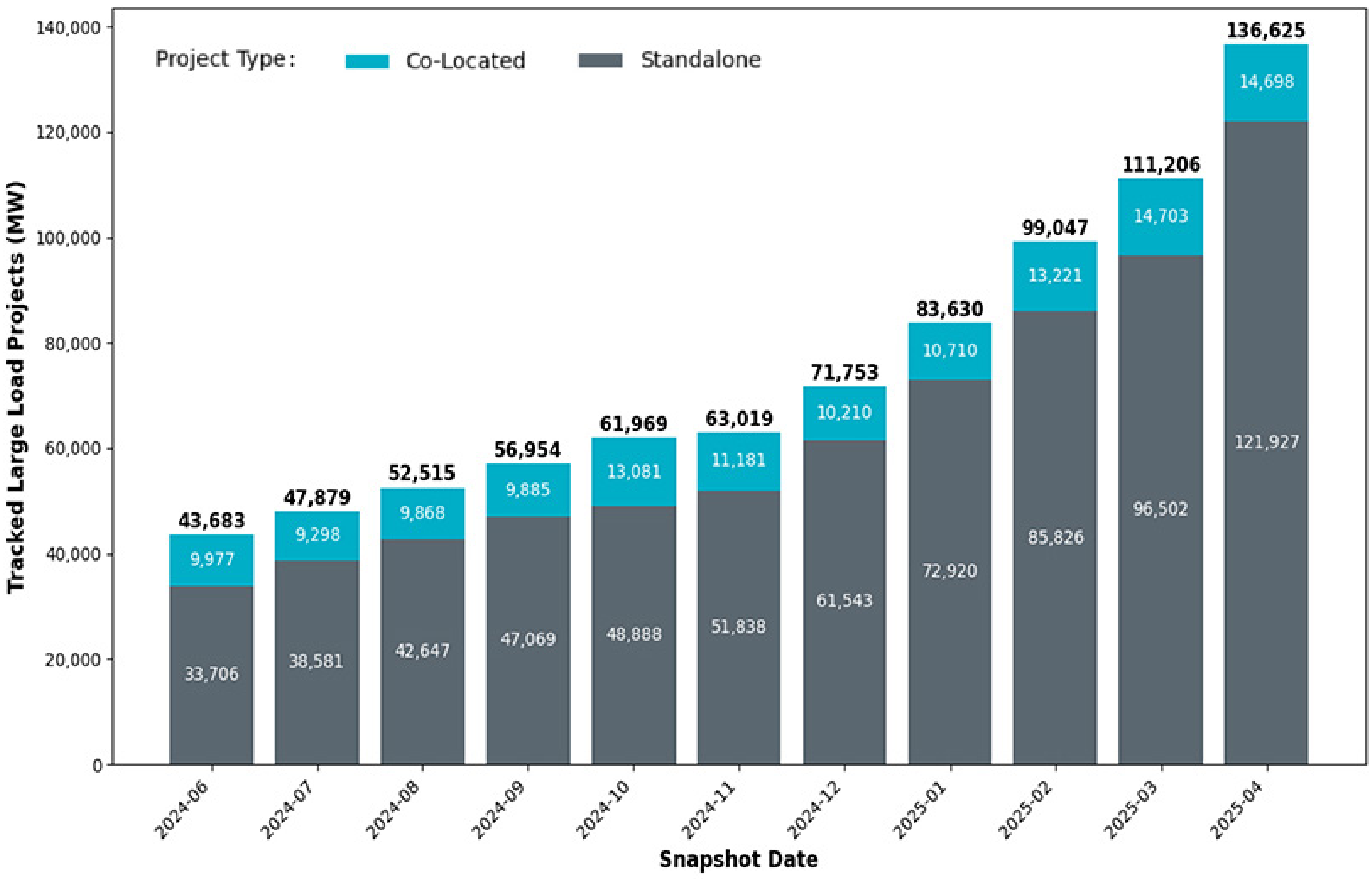
TAC also discussed *NPRR1275* but took no action on it. The *protocol change*, tabled at the Protocol Revision Subcommittee, would expand the qualifying pipeline definition for firm fuel supply service (FFSS) by including contractual natural gas storage in addition to on-site fuel storage.

FFSS was created by the Texas Legislature in 2021 after Winter Storm Uri nearly brought the ERCOT grid to its knees. Renewable resources took much of the blame in Texas, but FERC and NERC found the greatest share of fuel outages during the storm occurred among natural gas facilities. (See *FERC, NERC Release Final Texas Storm Report*.)

The Public Utility Commission also has a docket (*56000*) on FFSS. The commission agreed with staff's recommendation during its April 24 open meeting to delay FFSS' first procurement until the 2026/27 winter season.

Large Load Working Group OK'd

TAC agreed to sunset the Large Flexible Load Task Force and approved a charter that transitions the body into the *Large Load Working Group*, reporting to the com-



ERCOT's large-load interconnection queue continues to balloon. | *ERCOT* mittee. Members placed the motion on TAC's combination ballot, which passes for its consent agenda.

The task force's leadership asked for the changes during the committee's March meeting. The working group will be responsible for developing and recommending policies to facilitate the "reliable and efficient integration" of large loads into the ERCOT system. (See "Large Load Task Force to Remove 'Flexible,'" *ERCOT Technical Advisory Committee Briefs: March 26, 2025*.)

"There's enough activity going on with all the large loads that we don't see an end to the task force. There's a lot of activities that will probably be operations focused," said ERCOT's Bill Blevins, who chaired the task force.

Blevins said the group will return to TAC's May meeting with nominations for its leadership.

The working group is open to ERCOT stakeholders and representatives from the Public Utility Commission, the Independent Market Monitor, the Office of Public Utility Counsel and the grid operator's staff. It will address interconnection study processes and modeling requirements for large loads (75 MW and above) along with standalone considerations and issues related to co-locating the loads with on-site generation or other resources.

Staff told members that new standalone and co-located projects, as well as several project cancellations, resulted in a net increase of more than 25 GW in the large-load queue, as of March. The queue contains more than 136 GW of study requests, but a little more than 4.5 GW have been energized since 2022.

TAC Endorses $119M Oncor Project

TAC members endorsed a $119 million, 138-kV project in West Texas by placing it on the combo ballot. The Oncor project entails upgrading a 29-mile transmission line and updating other facilities and infrastructure to address reliability issues.

ERCOT's Regional Planning Group selected the project's route from among two other alternatives. One option came in at $247 million and the other at $81 million. With the cost exceeding $1 million, the grid operator's staff must bring the project to the Board of Directors for final approval.

Oncor expects to finish the project by December. As an upgrade, it does not require a certificate of convenience and necessity.

The combo ballot also included the approval of strategic objectives for TAC's Protocol Revision and Reliability and Operations subcommittees, and an NPRR and a system change request (SCR) that, pending board approval, would:

- *NPRR1271*: allow Mexico's state-owned electric utility, Comision Federal de Electricidad (CFE), to opt out of a requirement to designate a user security administrator and receive digital certificates. CFE is registered with ERCOT as a transmission and/or distribution service provider, a load-serving entity and a resource entity.
- *SCR830*: implement a machine-to-machine client credentials authentication flow using OAuth 2.0, allowing for certain read-only endpoints of the GINR Rest Application Programming Interface to be exposed for authorized use. ■

IESO Nodal Market Launch Successful

By Rich Heidorn Jr.

IESO successfully launched its nodal market May 1, reporting few glitches during its rollout.

The Ontario ISO added nearly 1,000 generation, load and intertie pricing nodes to replace its province-wide price while also creating a financially binding day-ahead market.

Nodal real-time prices ranged from $100 to $367/MWh as of mid-afternoon.

"It seems like everything kicked off without a hitch," said Portia Gilman, market monitoring manager for Yes Energy. The company's systems began receiving pre-dispatch data at 2 a.m. EPT and real-time pricing data about 4 a.m.

The *Market Renewal Program* is intended to improve the way IESO supplies, schedules and prices power. The ISO says the new market will save Ontario $700 million over the next decade through reduced out-of-market payments and increased efficiency.

IESO suspended the real-time market at 10 p.m. April 30 to begin the transition to the new market. It also temporarily stopped the use of its Prudential collateral system, implementing an alternative monitoring procedure until the system resumes on May 8.

The day-ahead market will not run on May 1 or May 2, subject to IESO's market failure rules (Chapter 7, section 4.3.2).

The ISO suspended automated electronic dispatches in the lead-up to the launch, announcing at 2:01 a.m. that HE03 pre-dispatch results would be published for the HE04 look-ahead period and used going forward. It said it would issue dispatch instructions verbally during the transition period.

At 3:07 a.m., the ISO acknowledged that market participants were having trouble accessing public and private reports from the HE02 pre-dispatch run, a problem it reported had been resolved by 8:25 a.m.

It said planned maintenance between 6:15 and 6:30 a.m. could cause three five-minute dispatches to be missed, and verbal dispatch instructions would be issued as needed.

Posting in the ISO's Power Data section should resume by the end of May 4, and static market content will be updated on the public website after the market suspension is lifted May 2.

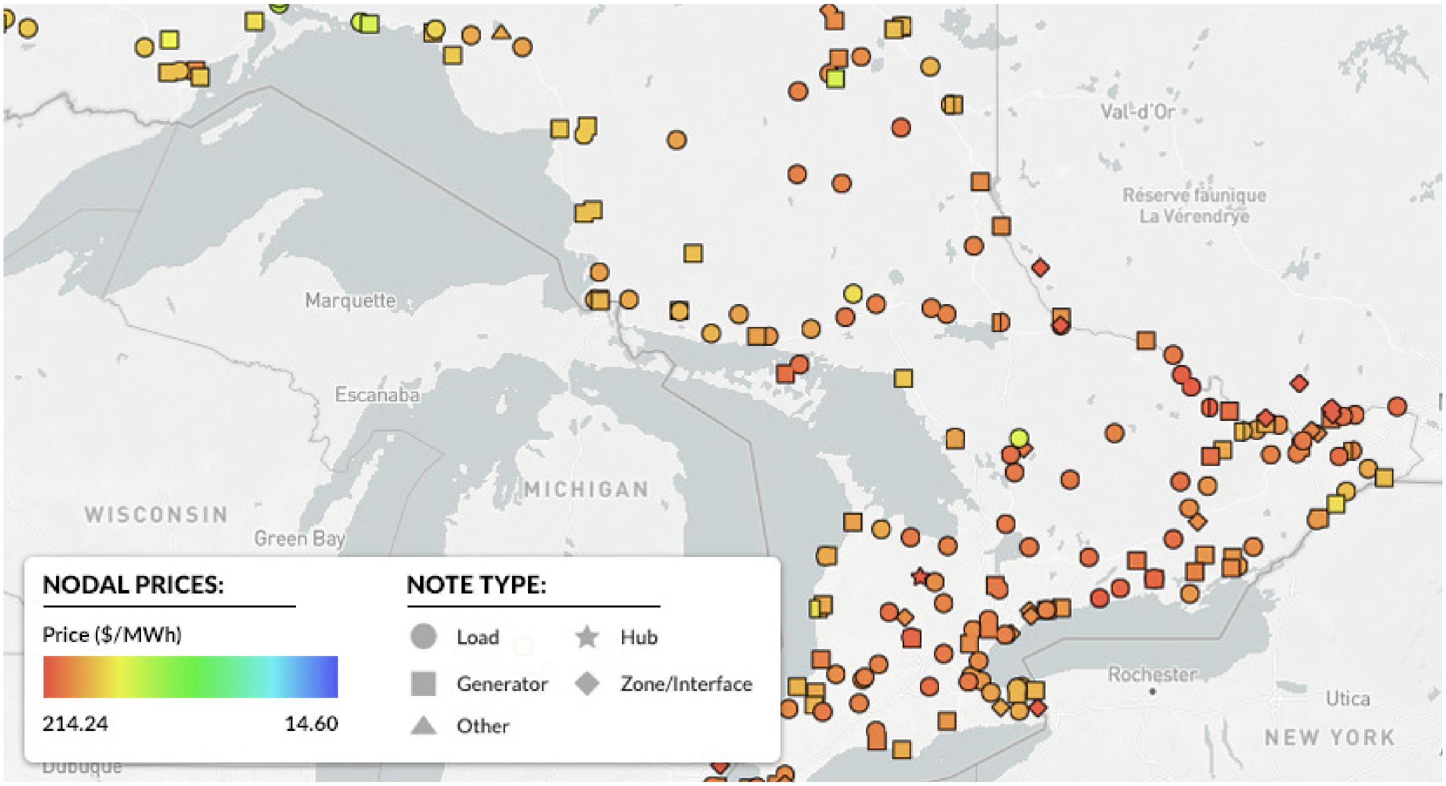
IESO says nodal pricing — which is used in all seven U.S. RTOs and ISOs — is crucial to efficiently dispatching and providing market signals to renewables and new resource types such as distributed energy resources, storage and hybrids.

Another milestone will come on May 8, when the ISO begins virtual trading in nine zones. (See *Ontario Introducing Nodal Market May 1*.) ■

[Note: *RTO Insider* is a wholly owned subsidiary of Yes Energy.]

Why This Matters

IESO's successful launch of its nodal market is the culmination of almost a decade of development and brings it into line with all seven U.S. RTOs and ISOs.



IESO real-time prices ranged from less than $15/MWh to more than $200/MWh as of 2:45 p.m. on the first day of the nodal market, May 1. | *Yes Energy*

IESO Opens Day-ahead Market in Nodal Rollout

ISO Proclaims Successful Transition to Nodal Market

By Rich Heidorn

IESO continued a smooth rollout of its nodal market, opening day-ahead trading for Ontario on Friday, May 2.

IESO's *Market Renewal Program* is intended to improve the way IESO supplies, schedules and prices power by creating a financially binding day-ahead market (DAM) and adding about 1,000 locational marginal pricing (LMP) nodes. The previous day-ahead commitment process was not financially binding, resulting in uncertainty for generators.

"The market transition has succeeded," the ISO declared Friday, calling an end to the market suspension it had issued during the transition to the new market. "The IESO confirms that there will be no rollback to the legacy market."

Day-ahead zonal prices for Ontario ranged from zero to $14.35 on Saturday, May 3, the first day of DA trading, rising only as high as $6.54/MWh on Sunday, May 4. With the return of the work week, DA prices topped out at $51.20 for 8 p.m. Monday and $58.61 for 7 p.m. Tuesday.

DA LMPs since May 3 have ranged from $0/MWh to $85.60 — at hour ending 21:00 May 6 from an intertie in the Northwest zone.

Real-time prices for the Ontario zone have ranged from near zero to a high of $389/MWh at 3:25 p.m. May 5.

Peak demand for the first five days of the nodal market ranged from less than 15.1 GW (May 3) to almost 16.3 GW (May 1) with a projected peak of 16.4 GW for May 6.

On May 5, RT prices in the West electrical zone north of Lake Erie hit the $2,000/MWh price ceiling for intervals ending 7:40 a.m. EPT to 7:55 a.m. EPT.

The cause of the spike is unclear, partly because Ontario publishes much of its constraint data on a six-day lag.

On Saturday, the ISO announced its Commercial Reconciliation System had been updated and was fully operational, meaning the ISO's rules for settlement of the renewed market were in effect.

The ISO experienced a couple technical glitches, reporting on Saturday that its day-ahead market phone line was not working and referring urgent issues to its real-time operations.

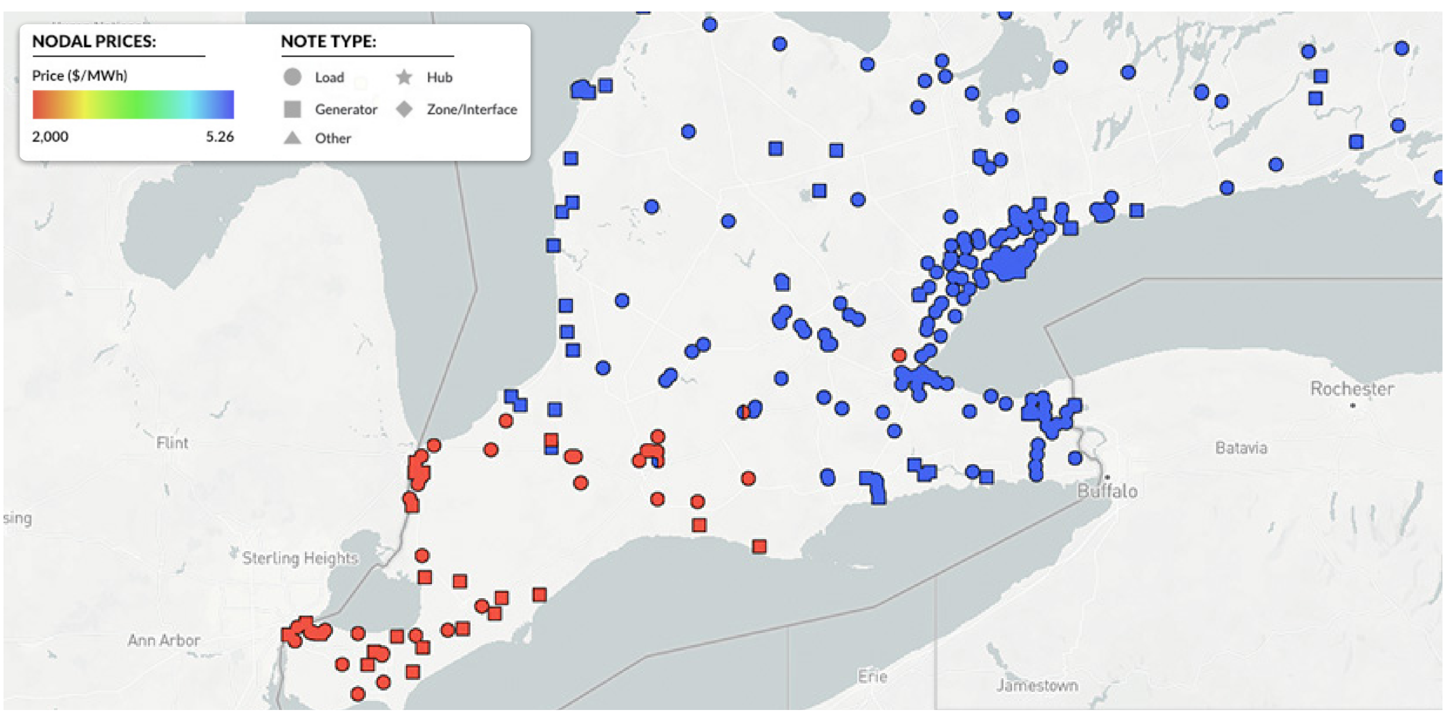
Why This Matters

The successful rollout of the IESO's day-ahead market came just days after launch of its nodal market, prompting the ISO to confirm "there will be no rollback to the legacy market."

On Sunday, it reported that an "unplanned tool outage" had made its Energy Market Interface (EMI) and Energy Market Administration Tool (EMAT) inaccessible.

As of late Monday, May 5, IESO had not posted any subsequent notices saying the problems had been corrected. IESO did not respond to a request for comment.

The nodal market launched May 1 should save Ontario $700 million over the next decade through reduced out-of-market payments and increased efficiency, according to IESO. ■



Nodal real-time prices in the West electrical zone north of Lake Erie hit the $2,000/MWh ceiling (red nodes) for about 15 minutes on the morning of May 5, at a time when prices elsewhere in Ontario were in the $15/MWh range (blue nodes). | *Yes Energy*

IESO Tweaks Modeling for Outage Management

By Rich Heidorn Jr.

Why This Matters

IESO's changes to its Reliability Outlook will improve its alignment with other forecast reports and make it slightly easier to schedule summer outages.

IESO is incorporating a wider range of risks in its *Reliability Outlook* (RO), an 18-month forecast used to manage generator and transmission outages, a move it says will make it slightly easier to schedule summer outages.

The new probabilistic approach departs from the outlook's deterministic focus on "normal" and "extreme" weather scenarios. The new methodology also changes how the ISO projects hydro and wind output and how it accounts for imports and planned loads.

The changes will bring the RO in line with best-practice forecasting methodologies and is a better fit for the evolving supply mix, with increased solar, storage and other distributed energy resources, IESO officials said during a recent *briefing*.

The ISO uses the RO to comply with NERC and Northeast Power Coordinating Council reliability standards. Bonnie Chan, manager of planning assessments, said the ISO completed its shift with the publication of its RO *methodology* in late March.

The changes "will make sure that resource planning decisions are based on the most accurate, data-driven insights possible, helping us better align planning efforts with what's happening in the market," said Fatema Khatun, a stakeholder engagement adviser.

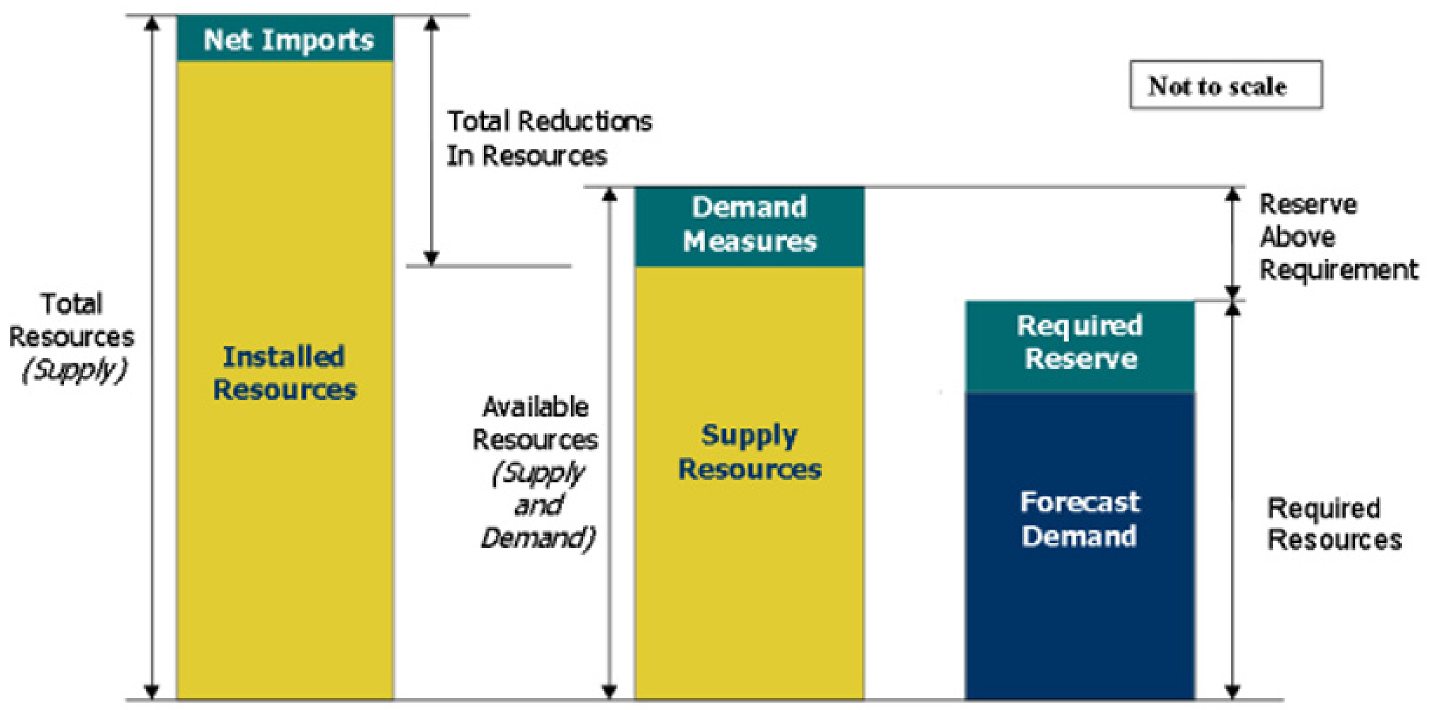
The new approach is a response to stakeholder feedback and a recommendation from the Market Surveillance Panel that the ISO improve the RO's alignment with two other forecasts: the *Adequacy Report*, which focuses on Ontario's electricity requirements for the next 34 days, and its *Annual Planning Outlook*, a 20-plus-year look used for evaluating long-term investment decisions and resource acquisitions.

IESO's metric for determining resource adequacy is called the Reserve Above Requirement (RAR). The ISO begins its evaluation by derating its installed resources and imports based on factors such as effective forced outage rates. The resulting "available" resources are measured against the projected demand forecast and required reserves. If there is excess capacity, the ISO has a positive RAR.

Weather Scenarios

The RO previously used a deterministic approach to calculating resource adequacy based on an "extreme" weather scenario and the assumption it would be able to rely on up to 2,000 MW of imports year-round.

The outlook used 31 years of weather history — dry bulb temperature, dew point, wind speed and cloud cover — from



IESO begins its resource adequacy evaluation by derating its installed resources and imports (left column) based on factors such as effective forced outage rates. The resulting "available" resource stack (middle column) is measured against the projected demand forecast and required reserves. If there is excess capacity (right column), the ISO has a positive Reserve Above Requirement (RAR). | *IESO* six weather stations between Windsor, Ottawa, Toronto and Thunder Bay to generate normal (50/50 probability) and extreme (maximum) demand forecasts. The approach was limited in its simplified output projections for embedded wind and solar.

IESO will continue to use 31 years of weather history but add a new data source for predicting production from its 2,000 MW of embedded solar capacity: *Global Horizontal Irradiance* (GHI), which measures the total solar radiation received on horizontal surfaces.

"Cloud cover is not necessarily the most accurate input for our solar models," said Andrew Trachsell, senior demand forecaster. "Unlike the previous methodology, where you're looking at cloud cover at [a weather station] that could be 50 km away [from a solar farm], this [GHI] data is at a very granular level — at 2 by 2 km — so it is a much more detailed or accurate input."

Demand Scenarios

IESO is also changing how it accounts for new demand in the province, which has been increasingly targeted by large loads seeking low-carbon power.

It will use a "planned" scenario to account for loads that are less certain to reach commercial operation during the forecast period but large enough to warrant consideration because of their potential impact on grid operations. Its "firm" demand scenario will be limited to loads with a high probability of going into operation during the forecast horizon.

The former approach, which used a monthly normalization, resulted in higher demand peaks, particularly in the summer.

"The previous methodology attempted to put a monthly peak — which is a peak at a higher level with certainty, and less uncertainty above it — into the forecast, and then apportion that monthly peak across the week," Trachsell said. "Now we've moved to just strictly the weeks, and that means that you're going to get a lower peak with certainty, but much more … variability above it."

Wind and Hydro

IESO also has begun using probabilistic distributions to model wind and hydro production instead of using a median value for each week. That allows it to capture a broader range of risks, including the tail ends of low and high hydro and wind conditions.

In the past, modelers used a monthly median of production plus scheduled operating reserves. 2012 was the proxy for the driest year, with 800 MW of hydro subtracted for the summer months.

"Before we looked at it more deterministically, we had the normal and extreme, and that was kind of like the bookends and we used the extreme weather scenario to do outage management and decision making," said Emanuel Moldovan, senior planner. "There's no more bookends. It's just one scenario."

Trachsell said the ISO's previous method also "forced everything into a normal distribution, with an assessment of what the uncertainty around that normal was that had to be calculated. And once again, this was a fixed approach that was not necessarily as robust as it could be."

The new methodology models wind on a *Weibull distribution* in all months, which the ISO says is more accurate in accounting for low wind periods. A Weibull distribution is also more flexible than the normal distribution and can be used to model a wider range of data shapes, including skewed and non-normal data.

LOLE Allocation

As the region's Planning Coordinator, IESO is charged with ensuring the loss-of-load expectation (LOLE) averages no more than one day every 10 years, the limit set by NPCC.

Going forward — "pending ongoing monitoring of the situation," Moldovan said — the ISO will allocate 30% of the LOLE risk to the summer (May to October) and 70% in the winter (November to April).

The new approach will reduce the RAR in the winter and increase it in the summer, making it slightly easier to approve outages in the summer. "Although the winter RAR is decreasing, current system conditions do not indicate a need to reschedule outages due to resource adequacy concerns in the winter months," IESO said.

Imports

Assumed imports will be reduced from 2,000 MW to 1,000 MW in winter in both the RO and the Adequacy Report to account for IESO's capacity agreement with Hydro-Quebec, which needs firm capacity from Ontario during those months.

Overall, while the new methodology considers a wider range of risks, "the results are similar to the previous approach and should result in minimal changes for outage management," IESO said. ■

FERC-NARUC Collaborative Examines Ongoing Issues with Gas-electric Coordination

Both Sectors Still Grappling with Disconnects Between Business Models

By James Downing

Why This Matters

As other firm resources continue to retire, gas-fired generation is only growing in importance on the grid, partly because its operating characteristics help to balance the variability of renewables.

It's been more than a decade since participants in the natural gas and power sectors identified the lack of gas-electric coordination as a key risk for the operations of both industries.

And while there's been progress since then, the steady growth of gas-fired generation and continued disconnect between the sectors' business models gave the Federal-State Current Issues Collaborative plenty to discuss on the subject during an April 30 meeting at FERC headquarters.

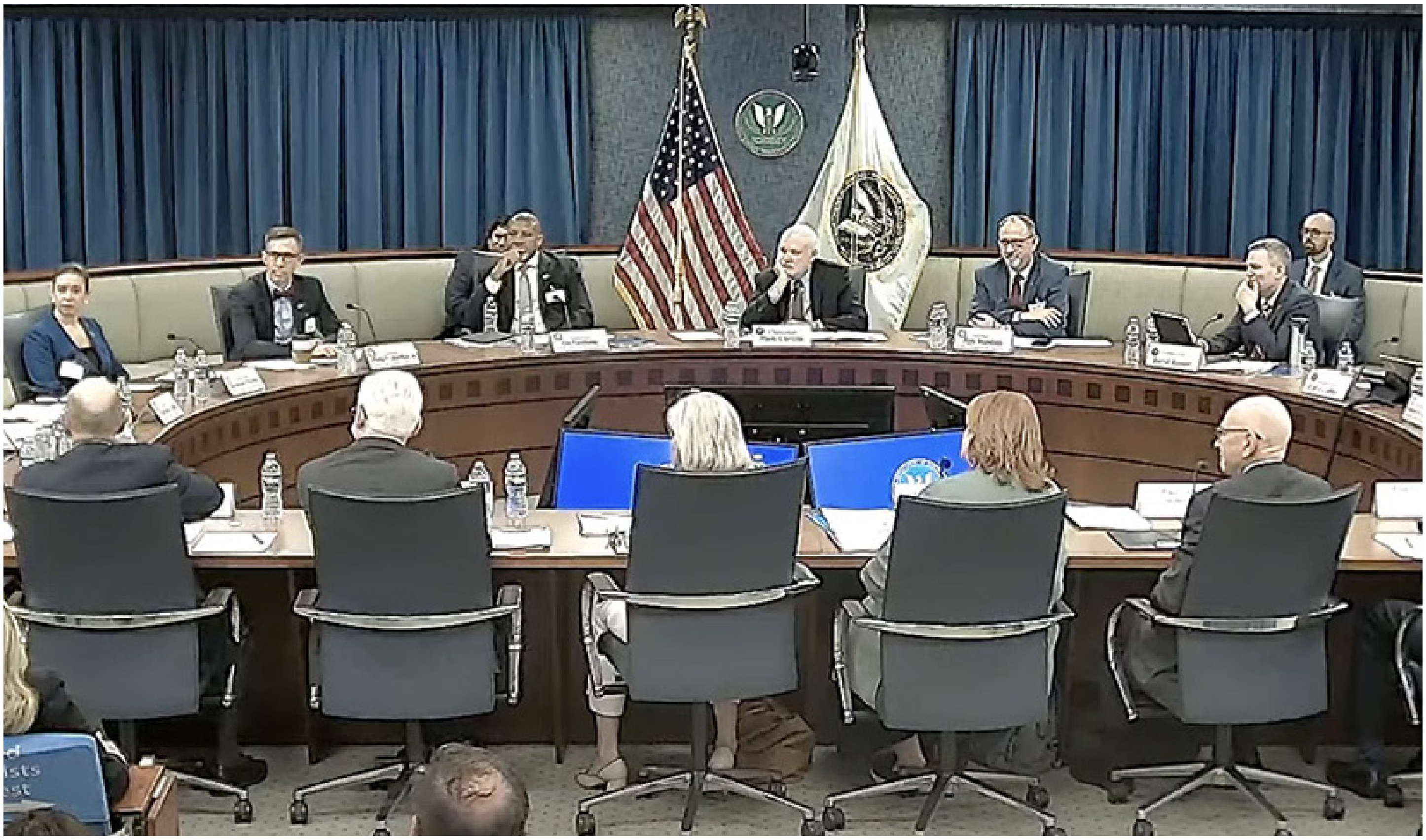
"I think I saw a number that 47% of all power gen in America now is gas," FERC Chair Mark Christie said at the meeting, which brought together representatives of FERC and the National Association of Regulatory Utility Commissioners (NARUC). "So, gas has become just absolutely critical to our to our electric system's reliability."

But gas also is important to manufacturers, as well as residential and other end-use customers who rely on the fuel to stay warm in winter, he added.

Gas generation is important to the grid not only for the huge volume of power it produces, but also because its operational characteristics enable it to balance intermittent resources, which have been growing rapidly, NERC CEO Jim Robb said.

"I've also been a very outspoken critic of the state of natural gas-electric industry coordination since my time as the CEO of WECC in the Western Interconnection and over the past seven years in my time as the CEO of NERC. I've described these challenges as the most admired problem in the energy sector, and it's time to stop admiring them," Robb said.

The electricity industry has experienced five well-publicized winter reliability events over the past 14 years that implicated gas-electric coordination, though changes made in response to those events bore fruit this past winter as industry participants made it through several weeks of arctic cold without incident, he added. (See *FERC, NERC Say Grid Winter Recommendations Working*.)



The Federal-State Current Issues Collaborative meeting on electric-gas coordination on April 30 at FERC headquarters. | FERC

But more work is needed, as highlighted by the massive April 28 blackouts on the Iberian Peninsula. It will take some time for the industry in Spain and Portugal to determine the cause of the outages, and it could be weeks before the true causes are known, Robb said.

"There are, however, a couple of observations that do seem clear," he said. "By all open-source reports, there was very little traditional generation in operation at the time of the cascade. While other factors may play a role, the lack of spinning generation and the inherent inertia it creates undoubtedly allowed the situation to spiral out of control more quickly than had those plants been operating."

Lack of Inertia

Inverter-based resources such as wind and solar do not offer the grid the same levels of inertia that a large spinning mass provides, which means when grid frequency deviates from a stable level, there are fewer resources capable of absorbing that change, allowing outages to cascade more broadly, Robb said. Some new inverters could address that issue, but the technology has not been proven, he said.

Largely islanded systems, like those in ERCOT and the U.K., already are running into inertia issues today, said ISO-NE CEO Gordon van Welie. But those problems are not expected to be felt in the Eastern Interconnection for another decade or so, he said.

Van Welie contended that gas-electric coordination issues are still relevant today because the gas system and electric grid are really one system aimed at delivering energy. ISO-NE's position at the end of the gas pipeline network, without any local supplies of the fuel, makes those issues more acute for New England.

"Fundamental differences between the gas and electric markets require acknowledgment and specific actions to mitigate and/or account for those differences," van Welie said. "The electric system is planned and built on forecast mode, while the gas system relies on ad hoc, long-term customer contracts. This makes it difficult for the gas and electric systems to function efficiently as interdependent systems."

He pointed out that gas pipelines are built based on firm contracts signed with demand, and that there is no central planning to meet peak demand plus a reserve margin like on the power grid.

Ohio Public Utilities Commissioner Dennis Deters asked what can be done with large data centers that are "bringing their own generation" to get to market quickly and what impact that could have on the gas system.

That development illustrates the possibility that the gas industry is not planning for new demand, van Welie said.

'Intense' Planning

But natural gas utilities do have to plan to meet demand on the coldest day of the year, when the gas system delivers three times as much energy as the grid does on the hottest day, American Gas Association CEO Karen Harbert said.

"We do have intense resource planning, and we do have long-term contracts so that the people that have contracted for the gas get the gas — full stop," Harbert said.

She said data center operators used to start their development process at offices of state governors, seeking to get the best tax treatment possible.

"And then the last place they would go would be the utility. Where's the first place they are going now? It's the utility," she said.

That allows the utilities to explain how much headroom is available on their system and how long it could take to connect major new demand, she added. Those questions increasingly are driving where data centers go, and Harbert said it's important to keep those facilities in the U.S.

Harbert expressed agreement with many in the electric sector that new pipelines and other infrastructure — especially storage — will be needed to ensure reliability for both systems. The politics of expanding pipelines in New England have for years been fraught, but van Welie said an increased focus on affordability in the region could start to change that.

"I think the real gap, though, is that there was an unintended consequence when we restructured the industries, particularly the electric industry, 25 years ago," van Welie said. "So, in a place like [Dominion Energy's Virginia territory] or in Florida, when you build a new gas power station today … you bring the package along to the state regulator and you get approval for the whole thing — the power plant, plus the firm gas transportation contracts, which then results in infrastructure. So, when we unbundled the industry 25 years ago, we broke those linkages."

Contributing to the problem is the fact that local gas delivery companies must plan around firm load for their direct customers, but not for electric generators. Resolving that issue is important to both industries because extreme cold can cause issues on either the gas or electric system that then degrade the reliability of the other, as seen in Texas in February 2021 during Winter Storm Uri, van Welie said. (See *Texas Supremes Hear Arguments in Last Uri Case*.)

"It's not a criticism, it's a reality," van Welie said. "We're not planning it to meet the full demand that's being placed on that system, both the average demand that we placed on it over time as well as the instantaneous demand that is placed on it for purposes of balancing the electric system."

Expansion of gas storage represents one way to deal with the issue. On that front, the gas industry has increased the amount of LNG storage in the Northeast in recent years, since the region lacks the right geology for natural storage caverns, Harbert said.

But while that helps her members, the disconnect in the business models means the issues van Welie highlighted are still there.

Dominion Energy Virginia has faced nothing like the issues New England confronts around gas-electric coordination, but the fuel has become the backbone of its system in recent years, said Edward Baine, the company's president of utility operations. The utility won approval in February for its Brunswick-Greensville LNG storage facility to serve two of its gas plants that lacked alternative supplies.

"Between 2019 and 2023, these two power stations contributed more than 25% of the company's energy production and achieved a combined capacity factor of approximately 75%," Baine said. "Importantly, Brunswick and Greensville are two power stations in our fleet that do not presently have on-site backup fuel or access to multiple gas facilities." ■

NEPOOL Supports Timeline Revisions for ISO-NE Order 2023 Compliance

By Jon Lamson

The NEPOOL Participants Committee on May 1 voted to support an expedited filing adjusting several key dates in ISO-NE's compliance proposal for FERC Order 2023.

The commission approved ISO-NE's compliance filing on April 4, but several dates included in the filing are no longer viable (*ER24-2009, ER24-2007*). (See *FERC Approves ISO-NE Order 2023 Interconnection Proposal*.)

To preserve the general timeline of its proposal, ISO-NE intends to push back most dates and deadlines in its original filing by about a year. This would enable the RTO to run a group study for late-stage interconnection requests that lack capacity interconnection rights. The group study would precede the main transitional cluster study, which is likely to begin in October.

A proposed revision by RENEW Northeast failed to garner enough support to pass despite support from the NEPOOL Transmission Committee. RENEW proposed to let customers with late-stage interconnection studies continue their system impact studies (SISs) until Aug. 30, arguing this could help these developers avoid restarting their studies. ISO-NE stopped working on all in-progress SISs after FERC approved its compliance proposal. (See *ISO-NE Prepares Expedited Filing After Ruling on Order 2023 Compliance*.)

Prior to the meeting, NEPOOL Counsel Pat Gerity told members that the Participating Transmission Owners Administrative Committee did not support filing the changes with RENEW's revision. He wrote that, "because of the shared filing rights that are implicated, the ISO does not believe it will be in a position to file the TC-recommended Section II revisions."

The revision fell short of the two-thirds threshold required for PC support, with 59% of the committee voting in favor at the meeting May 1.

The PC also voted to support changes to a pair of definitions in the ISO-NE Financial Assurance Policy and approved minor changes to the operating procedures for transmission outage scheduling and metering and telemetering criteria.

Operations Report

Energy market revenues significantly increased in April compared to the same month last year, ISO-NE COO Vamsi Chadalavada told the PC.

Average day-ahead and real-time hub LMPs increased by more than 65% year-over-year. The revenue increase was largely driven by more-than-doubled natural gas costs.

EMC Enineering Services

ISO-NE's day-ahead ancillary services (DAAS) market, which the RTO launched at the beginning of March, had an average daily total value of about $15 million. Following a significant price spike after the market launch in early March, DAAS prices have remained relatively stable, but they did experience a smaller spike during a period of cold weather and elevated demand in early April.

The system did not experience any emergency conditions but did experience the lowest minimum load in ISO-NE history. (See *Growth of BTM Solar Drives Record-low Demand in ISO-NE*.) ■

FERC Accepts ISO-NE Compliance Filing on Interconnection O&M Costs

FERC on May 2 accepted a compliance filing by ISO-NE and New England transmission owners eliminating interconnection customers' responsibility to pay for the operations and maintenance costs of network upgrades (*ER25-1324*).

The commission ordered an additional filing to address potential issues regarding refunds for O&M costs incurred after its initial ruling in December 2024. (See *FERC Sides with New England Developers on Interconnection Complaint*.)

"The compliance filing largely complies with the [commission's] directive to remove from the tariff any language providing for the assignment of O&M costs for network upgrades to interconnection customers," FERC wrote.

The commission also accepted tariff changes broadening the definition of an "interested party" in the New England TOs' formula rate protocols, which should enable a wider range of groups to participate in proceedings.

NEPOOL, RENEW Northeast, Advanced Energy United and the Alliance for Climate Transition supported the filing, while the New England Power Generators Association and CPV Towantic expressed concern that it would inadvertently limit refunds to payments made after the December order, leaving out advance payments for costs incurred after.

FERC directed ISO-NE and the TOs to make an additional filing within 30 days "to clarify that network upgrade O&M costs accrued on or after Dec. 19, 2024, will be returned to the interconnection customer, regardless of whether the interconnection customer made advance payments prior to" that date. ■

— Jon Lamson

Massachusetts Lawmakers Focusing on Energy Affordability in 2025

By Jon Lamson

In the wake of skyrocketing energy costs over the past winter and the loss of federal support for state clean energy initiatives, Massachusetts policymakers are facing difficult questions about balancing decarbonization with energy affordability in the state's 2025/26 legislative session.

Lawmakers have passed major climate and energy bills in each of Massachusetts' past three sessions. Most recently the House and Senate agreed to compromise legislation after the conclusion of formal sessions in 2024, overhauling clean energy permitting and siting, updating utility regulations to enable gas pipe decommissioning and authorizing a sizeable procurement of energy storage resources. (See *Mass. Clean Energy Permitting, Gas Reform Bill Back on Track* and *Compromise Climate Bill Finally Approved by Mass. Legislature*.)

The two prior bills, passed in 2021 and 2022, included sector specific decarbonization targets, a new opt-in municipal building code, authorization for offshore wind procurements, electric vehicle rebates and EV sales mandates.

Sen. Mike Barrett (D), co-chair of the legislature's Joint Committee on Telecommunications, Utilities and Energy (TUE), told *RTO Insider* his "first priority is to make sure Massachusetts emerges from the Trump years with its climate capacity intact."

"We are basically trying to change over an entire economy," Barrett said. He added the state should avoid "unintentionally paralleling federal cutbacks with cutbacks of our own. We can't compensate literally for the missing federal dollars, but we want to sustain a very serious state effort, rather than throw up our hands."

What's Next

The administration of Gov. Maura Healey is preparing to file an affordability bill, which will likely serve as a starting point for negotiations over how to bring down energy costs in the state.

The Massachusetts State House in Boston | *Shutterstock*

If the Trump administration prevents additional offshore wind procurements, Massachusetts should consider focusing its efforts on rooftop solar, which does not rely on federal approvals, Barrett said. He added the state's decarbonization strategy is meant to be flexible, and the state could amend its clean energy procurement laws to readjust its strategy.

Barrett also emphasized the importance of maintaining sources of work for the state's clean energy workforce throughout President Donald Trump's second term, and that pivoting toward distributed energy resources could help provide these opportunities.

"You might concede that Trump can slow you down, but you don't want to give him the opportunity to destroy the effort altogether," Barrett said.

Rising Energy Costs

The winter of 2024/25 was the first since 2014 to feature sustained below-normal temperatures, driving a significant increase in natural gas prices and demand. On Feb. 1, gas supply rates increased 16 to 22% for customers of the state's investor-owned gas utilities. The supply rate increase coincided with increased delivery fees, which were caused in part by adjustments to the Mass Save efficiency program and continued investments to repair and replace leaky pipes.

High residential energy costs caused significant public pressure on state officials to provide ratepayer relief, and the Department of Public Utilities required temporary reductions in delivery fees and ordered $500 million in cuts from the 2025/27 plan for Mass Save "to protect ratepayers from excessive bill impacts." The Mass Save cuts drew some criticism from clean energy advocates, who argued the move would hurt ratepayers in the long run.

Meanwhile, Gov. Maura Healey (D) *announced* in March an "energy affordability agenda," returning to ratepayers $125 million in funds collected from alternative compliance payments for state clean electricity standards. Healey also committed to filing "an energy affordability and independence bill to explore new ways we can make Massachusetts more affordable."

Residential Competitive Supply Ban

Heightened attention on energy costs may boost efforts to ban competitive residential electricity suppliers, a proposal that fell short in the negotiations for the 2024 compromise bill. Healey, the Office of the Attorney General (AGO), the city of Boston and top senators all expressed support for a ban during the session, but the proposal ultimately was derailed by opposition in the House.

Competitive suppliers in the state currently are allowed to market directly to ratepayers, and the state has struggled to prevent predatory suppliers from locking customers into deceptive and expensive supply contracts. Supporters of the industry have argued that predatory practices can be addressed through reforms, while critics have argued that a ban is the best way to protect consumers.

"I don't think any of us are backing off on the determination to bar competitive suppliers from selling to low-income households door to door," Barrett said.

A *2024 report* by the AGO estimated that residential customers of competitive electricity suppliers paid over $577 million more than basic utility service customers over an eight-year period. The report also found that "low-income consumers and people of color continue to suffer a disproportionate amount of the consumer harm."

Larry Chretien, executive director of the Green Energy Consumers Alliance, said a ban is "is likely the easiest thing to do to make energy more affordable, because it doesn't require taking money from one account … it doesn't require tax dollars, and it doesn't require raising one person's rate to lower another person's rate."

"We're going to hope that the House takes an open-minded view of this," Chretien added.

Utility Reforms

While lawmakers and advocates are quick to support the idea of energy affordability, in practice, the concept can motivate widely ranging policies with varying effects on decarbonization efforts.

Kyle Murray, director of state program implementation at the Acadia Center, said he would like to see the energy affordability bill include limits on utilities' return on equity, potentially restricting ROE to an average of the surrounding Northeast states.

"Our position has long been that utility return on equity is really inflated and could serve to come down a few points," Murray said, while also acknowledging that passing ROE reforms would be challenging due to the complexity of utility ratemaking and likely opposition from investor-owned utilities.

Murray also said he hopes lawmakers will consider changing the funding mechanism for some programs currently funded through volumetric charges in electricity and gas rates. He said funding programs like low-income discounts, Mass Save and renewable energy charges through fixed bill charges or through the tax base could save most ratepayers money.

He also expressed interest in legislation limiting the expansion of the state's gas network, a priority shared by Mass Power Forward, a large coalition of climate and environmental justice groups.

One of the main *bills* backed by the coalition would prohibit the state Energy Facilities Siting Board from approving new fossil infrastructure within five miles of state-designated environmental justice communities. The group also is pushing for *legislation* to prevent utilities from using ratepayer funds to cover the costs of industry associations, lobbying activities and promotional advertising.

Mass Power Forward coordinator Claire-Karl Müller said lawmakers should address utility incentives that encourage expansion of the gas network and undermine Massachusetts' decarbonization mandates and long-term strategy to reduce gas reliance. (See *Massachusetts Moves to Limit New Gas Infrastructure*.)

"If you're in a hole, stop digging," Müller said. "We have to stop expanding the gas system immediately."

The coalition's other priorities include a *proposal* to make fossil fuel companies pay for the costs of climate resilience through a "climate change superfund," as well as new *outdoor* and *indoor* air pollution protections for vulnerable communities.

Looking Forward

The state is in the early stages of its 2025/26 legislative session, which will conclude at the end of July 2026. Lawmakers already have submitted nearly 250 bills to the TUE committee, which has yet to begin bill hearings.

The House TUE co-chair, Rep. Mark Cusack (D), is new to the committee this year, and it remains to be seen whether his priorities will differ from Rep. Jeff Roy (D), who served as the House co-chair from 2021 through 2024. Roy was not reappointed to the committee after the Boston Globe reported he had a romantic relationship with a lobbyist working for clients regulated by the committee, including a third-party electricity supplier.

While no longer serving on the TUE committee, Roy has been appointed to House leadership by speaker Ron Mariano (D) and could remain an influential voice in the House on energy issues. Neither Cusack nor Roy responded to requests for comment.

Meanwhile, the Healey administration is expected to file energy affordability legislation in the near future, which should help define the scope of the legislature's discussions and negotiations on climate and energy issues.

A spokesperson for the Massachusetts Executive Office of Energy & Environmental Affairs said Healey soon will "file an energy affordability and independence bill to explore new ways we can make Massachusetts more affordable," adding that the administration "will use every tool we have to help make sure families and businesses can afford to heat their homes and keep the lights on." ■

ISO-NE's Final 10-year Demand Forecast Tapers Expectations

RTO Scales Back Estimated Contributions from EVs, Electrification

By Jon Lamson

ISO-NE has significantly lowered the peak load and net energy estimates in its final 2025 *10-year load forecast* but still predicts the region's peak demand will grow by over 2 GW by 2034, the RTO told its Planning Advisory Committee on April 29.

The reduced demand growth expectations are largely driven by reductions in ISO-NE's adoption forecasts for heating and transportation electrification. The RTO cut its electrification forecasts in response to data indicating that its previous forecasts significantly overestimated the adoption of electric vehicles and heat pumps. (See *ISO-NE Scales Back Vehicle, Heating Electrification Forecasts*.)

The final forecast predicts the RTO's summer peak for an average year will grow from 24,803 MW in 2025 to 26,897 MW in 2034. It expects the winter peak to grow more rapidly — from 20,056 MW in 2025 to 26,020 MW in 2034. Compared with the 2024 10-year forecast, ISO-NE reduced its 2033 summer peak projection by 2.1% and its winter peak projection by 7.1%.

The RTO expects the winter peak to surpass the summer peak at some point in the 2030s due to heating electrification.

The model predicts that average winter and summer peaks will be about equal by 2035, though the winter peak could pass the summer peak earlier under more severe winter weather conditions.

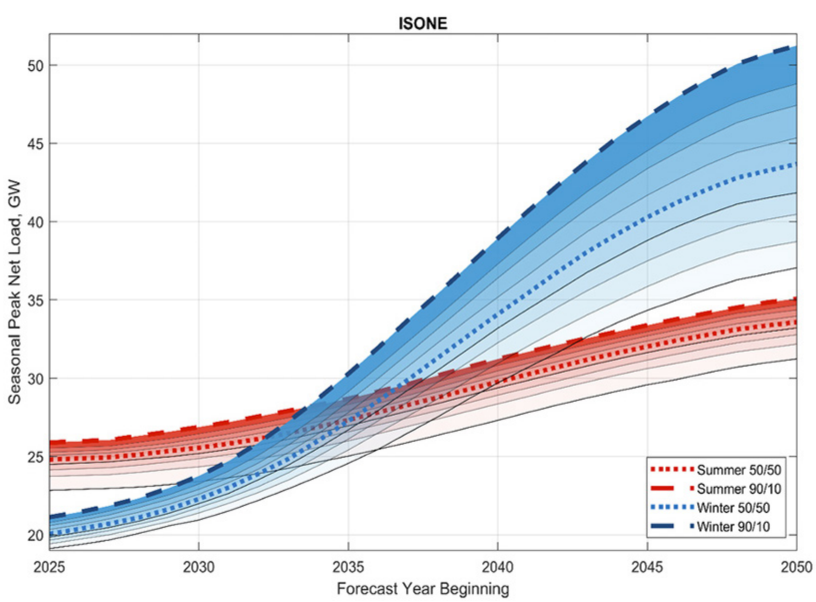
The projections also reflect major changes to ISO-NE's base modeling methodology, including the incorporation of hourly data, additional weather scenarios and climate change effects. (See *ISO-NE Cuts Winter, Summer Peak Load Forecasts for 2033*.)

Hourly modeling allows ISO-NE to evaluate "a wider variety of system conditions, not just peak loads," and capture peak loads that occur any time of day, not just in the evening, said Victoria Rojo, supervisor of load forecasting at ISO-NE. Rojo said ISO-NE expects morning winter peaks to become more common as load from heating electrification increases.

Based on an evaluation using the updated hourly forecasting, Pradip Vijayan, manager of transmission planning at ISO-NE, said the RTO *plans to* simplify its transmission planning studies to focus on just two scenarios: a midday peak high renewable scenario and an evening peak scenario.

"For transmission planning high net summer peak load analysis, the ISO proposes modeling 95% of the coincident gross peak load with 0% PV," Vijayan said, noting that, as the net summer peak load moves to later in the evening in the coming years due to rooftop solar, "this load level should cover both the coincident net peak load conditions in New England and non-coincident net peak loads for most load zones."

For the winter, he said ISO-NE plans to continue modeling the peak as "100% of the gross New England winter peak with 0% PV," noting the "significant variance in PV availability on high winter load days."



ISO-NE projected seasonal peaks through 2050 | *ISO-NE*

What's Next

ISO-NE plans to finalize and publish its 2025 Capacity, Energy, Loads and Transmission report on May 1.

Updated Interface Limits

Speaking also at the PAC meeting, Alex Rost, ISO-NE's director of transmission services, said the RTO will *increase* the Surowiec-South and the Maine-New Hampshire interface transfer limits to 2,200 MW because of network upgrades associated with the New England Clean Energy Connect (NECEC) transmission line. The Surowiec-South limit in Maine is currently set at 1,800 MW, while the Maine-New Hampshire limit is currently 2,000 MW.

Rost said the increase of the Surowiec-South interface will allow for the increase in the capacity import capability of the New Brunswick-New England interface from 980 MW to 1,000 MW.

The updated interface limits will be used in forward capacity market analyses, beginning with the overlapping interconnection impacts analysis for the 2025 interim reconfiguration auction qualification process, which will "determine whether there is sufficient capacity capability to qualify any proposed new capacity resources," Rost said. ■

Growth of BTM Solar Drives Record-low Demand in ISO-NE

By Jon Lamson

ISO-NE experienced record-low demand on Easter Sunday because of mild temperatures and high behind-the-meter solar output, making 2025 the fourth consecutive year the RTO has set a low-load record.

The 5,318-MW minimum load April 20 was a significant drop from the previous record low of 6,596 MW, set in April 2024. ISO-NE estimates that BTM solar production reduced systemwide demand by about 6,600 MW.

Steven Gould, director of operations at ISO-NE, said the RTO anticipated the low-load conditions days in advance and was able to forecast the minimum load with great accuracy.

"It was a very quiet day because we prepared and we communicated," Gould said. He added that the impact of declining minimum loads is "something that we are continuously looking at. We're fine now, but we want to be proactive, and that's what we're doing."

The region's solar boom has led to an increasing number of duck curve days, which are defined as days when daytime demand drops below nighttime demand. In 2024, New England experienced *100 duck curve days* for the first time in its history.

Largely driven by state policy, the region recently has added about 700 MW of BTM solar capacity per year, Gould said. Solar growth has been strongest in Massachusetts and Connecticut, which are home to about two-thirds of the BTM solar generation in the region.

Why This Matters

The rapid growth of behind-the-meter solar has caused a growing duck curve in New England. ISO-NE anticipates that energy storage, electric vehicles and heat pumps eventually will increase midday power demand in the region.

Gould said the "biggest concern at light loads" is the creation of high-voltage conditions on the transmission system. He said ISO-NE coordinates with the region's transmission owners ahead of forecasted light-load periods to ensure the system has resources available to reduce the voltage on the system.

Light-load conditions also create the need for significant ramping capabilities as solar production wanes in the evening. On April 20, natural gas generation dropped from over 4,700 MW in the early morning to about 1,800 MW between 10 a.m. and 3 p.m., before increasing in the evening to over 5,000 MW as the systemwide peak grew to about 11,800 MW.

"We have the resources to [ramp back up] at this point in time, and we're able to do it quite easily," Gould said.

Power system emissions, which are largely driven by natural gas generation, especially during warmer months, were cut roughly in half during this midday period, before increasing again in the evening.

Nuclear generation, which lacks the ability to quickly increase or decrease production, remained steady at 2,115 MW throughout the day. In the future, Gould said he does not expect low loads to create operational issues for nuclear resources because the region can export power to neighboring regions during extreme low-load conditions.

On April 20, ISO-NE went from importing about 1,500 MW in the morning to exporting power midday to NYISO as New England's real-time hub LMP dropped to as low as $31.7/MWh. Imports climbed back to about 1,000 MW in the evening.

Looking forward, Gould said he expects the growth of transportation electrification and electric storage to eventually drive up midday demand, helping to mitigate potential low-load concerns.

"We think battery storage and electric transportation and heat pumps will be able to curb the light load, because that will be the lowest energy price for those resources to charge their systems," Gould said. "If you look at Texas and California, they're very much ahead of us for battery storage, but that's what they're doing."

Steven Gould, ISO-NE | *ISO-NE*

Over the next decade, ISO-NE *anticipates* BTM solar production to nearly double, growing at a rate of about 570 GWh per year. ISO-NE expects this growth to push the system peak load later in the day but does not expect it to have a major impact on peak loads levels. By 2034, ISO-NE *expects* BTM solar growth to reduce the summer peak by an additional 140 MW and the winter peak by about 400 MW.

However, Gould emphasized the difficulty of forecasting system conditions years in advance, "especially when you go from one [federal] administration to a new administration," pointing to the struggles and uncertainties surrounding offshore wind development.

"Things are dynamically changing," Gould said. "We're doing lots of studies. … We're taking about light loads; we're looking at ramping; we're looking at intermittent resources; we're looking at forecasting irradiance; we're looking at forecasting wind and forecasting demographic behavior, and putting it all together to make sure we have adequate resources in our market on a daily basis." ■

MISO Petitions 8th Circuit in Dispute with SPP over Data Center-strained Flowgate

Proceeding Centers on Congestion Stemming from North Dakota Crypto-mining Facility

By Amanda Durish Cook

MISO is seeking judicial review of two related FERC decisions preventing the RTO from recouping costs or revising a joint procedure with SPP over a shared North Dakota transmission line that has become congested by a new cryptocurrency mining facility.

The RTO on May 1 filed a petition for review with the 8th U.S. Circuit Court of Appeals over the commission's previous orders declining a request that SPP refund MISO members or change procedures around the overworked 230-kV Charlie Creek flowgate (*ER24-1586, et al*).

The flowgate ran up tens of millions of dollars in congestion after the Atlas Power Data Center in Williston, N.D., activated on the SPP side of the line in 2023. MISO and its member Montana-Dakota Utilities maintain that associated market-to-market (M2M) settlements unfairly involved MISO in SPP's localized issue brought on by 200 MW of poorly planned data center growth.

FERC in March denied requests by both MISO and Montana-Dakota Utilities for rehearing to obtain refunds from SPP or cancel eligibility for the flowgate's ongoing M2M coordination. The commission said the Charlie Creek Flowgate passed the RTOs' flowgate eligibility studies for such coordination. (See *FERC Again Declines Changes, Refunds on Crypto-burdened MISO-SPP Flowgate*.)

The Atlas Power Data Center in Williston, N.D. | *KFYR TV*

Why This Matters

The 8th Circuit's decision could alter the process by which MISO and SPP designate M2M status of flowgates on the seam between the two RTOs.

According to the agreement between the RTOs, MISO must secure SPP's permission to remove M2M coordination from the flowgate.

MISO also unsuccessfully sought for FERC to alter the MISO-SPP interregional coordination process — which manages flowgates — to make it easier for one RTO to revoke M2M status on a line if it doesn't think the designation can assist with relieving a constraint. FERC decided that while a section of the two RTOs' interregional coordination process says M2M coordination should be reserved for issues that are regional — rather than local — that requirement is not an explicit prerequisite for a flowgate to hold an M2M designation.

MISO has claimed that unwarranted M2M coordination has cost its members $38 million in charges to manage congestion on the flowgate, even as its members can only offer less than 1 MW of relief. However, FERC said SPP's evidence shows that revoking Charlie Creek's M2M flowgate status might risk the RTO needing to resort to transmission loading relief or load shedding.

MISO did not return *RTO Insider*'s request for comment on how much the RTO estimates its members are owed in refunds or whether it believes growing data center load would produce more flowgate issues at its seam with SPP. ■

State Regulators Weigh Drafting Alternative to MISO Tx Cost Allocation

By Amanda Durish Cook

Regulators of MISO states are mulling whether they should work together to offer up an entirely new cost allocation for the RTO's long-range transmission projects.

The Organization of MISO States' leadership said it will hold meetings on whether regulatory staff think FERC's Order 1920 should open the door for a new cost-allocation design for MISO's regional transmission projects. OMS members contemplated the idea at an April 28 meeting of the OMS Cost Allocation Principles Committee (CAPCom), with MISO South regulators appearing more open to shedding MISO's current, 100% postage stamp allocation to load used for long-range transmission projects.

Order 1920 directs RTOs to involve states when developing or amending a long-term regional transmission cost allocation. It gives states the go-ahead to meet independently to negotiate and devise cost-allocation methods to offer to FERC in place of RTOs' methods.

Regulators of some MISO states at the meeting said they're ready to pursue something different, while others said MISO's postage stamp status quo remains the best answer.

Minnesota Public Utilities Commissioner Joe Sullivan said OMS extensively examined MISO's cost allocation when MISO began planning long-range transmission projects. (See *FERC OKs MISO's Bifurcated Cost-allocation Tx Design*.)

Why This Matters

With an opportunity presented by FERC's Order 1920, the Organization of MISO States is checking in on members' willingness to propose an alternative to MISO's 100% postage stamp allocation to load for long-range transmission projects.

© RTO Insider

He said he didn't think OMS could do better this time around. "We had a really long process that I thought was really good about *ex ante* cost-allocation alternatives. I think I'm on record that we didn't find anything better," Sullivan said.

But Louisiana Public Service Commission attorney Noel Darce said MISO South states want a new method of subregional cost allocation in MISO, "something other than the postage stamp."

MISO South never has been the site of construction for a regionally cost-shared transmission project.

While Order 1920 dictates that project costs are allocated *ex ante*, or before the projects are built, states also have the option to negotiate with one another for up to six months after RTOs approve transmission projects to devise an alternative cost-allocation agreement for select portfolios.

MISO would have to file with FERC any alternative, all-encompassing cost-allocation design from states or their one-off alternative cost-allocation agreements, even if the RTO disagrees with it and files its own alongside the states' preferred approach. MISO also must file a backstop cost-allocation method to use if state negotiations break down. FERC and federal courts ultimately would make calls on which cost-sharing plan is most appropriate.

New Orleans City Council attorney David Shaffer said OMS first should check in among members to see whether the postage-stamp allocation remains appropriate, or whether "positions have changed." He said OMS should tackle that first before devising the potential state agreement process or assisting MISO with creating a voluntary funding process for projects that may not meet the RTO's benefit-cost ratio threshold.

Under Order 1920, MISO also must create a voluntary funding rule set that allows state entities and transmission interconnection customers the option to voluntarily fund some or all of the costs of proposed projects.

Shaffer said it's worth checking whether the states still believe the current approach is relevant and see "if there could be consensus on an alternative."

"I think we probably should address them individually," Shaffer said of Order 1920's to-do list.

"I think the question for us is: Do we want to take run at something different?" said Michigan Public Service Commission Chair Dan Scripps, also chair of OMS's CAPCom.

OMS said it will conduct an internal poll among regulators to gauge interest in designing a new cost allocation to take to MISO, at the suggestion of Mikhaila Calice, a staffer at the Public Service Commission of Wisconsin.

Scripps said OMS likely will take advantage of MISO Board Week in Minneapolis in June to meet face to face and discuss allocation options versus MISO's status quo.

MISO Sticks with Postage Stamp

Regulators asked if MISO is open to considering a new method of cost allocation.

MISO's Jeremiah Doner said based on MISO's assessment of Order 1920, MISO believes its current, postage-stamp allocation is fitting.

Doner said MISO is "largely going to be leveraging and developing" compliance through its long-range transmission planning and that it plans to tell FERC the "story" of its planning philosophy.

MISO "would point to the entirety" of the current structure used in its long-range planning in its compliance, including its approved cost allocation for long-range transmission projects, Doner said.

Doner added that OMS would embark separately on its own evaluation of current cost sharing and alternatives.

Order 1920 prescribes RTOs open a six-month engagement period with states for allocation evaluation. MISO kicked off its state engagement period by sending a letter to the Organization of MISO States. Because it was granted an extension from FERC, MISO's state engagement period lasts from March 11, 2025, to March 11, 2026.

The Mississippi Public Service Commission and the Louisiana Public Service Commission filed a motion to extend the state engagement period between MISO and state regulators by another six months, through Sept. 11, 2026. The two have asked other MISO state regulators to consider joining them in the request and said that "more time is needed to allow for complex cost-allocation discussions and a meaningful, consensus-based, long-term cost-allocation method and/or state agreement process."

MISO South representatives pushing MISO to try alternate allocation methods isn't new.

Prior to Order 1920, MISO itself suggested using a tailored allocation plan that involved splitting costs 50-50 between the MISO South subregion and the footprint's smaller cost-allocation zones. (See *MISO Suggests Changing Cost Allocation for South Projects*.)

MISO South regulators and Entergy in early 2024 countered with a proposal that would assign 90% of costs based on adjusted production cost savings and avoided reliability projects; the remaining 10% would be divvied up among new generators interconnecting in MISO South using a flow-based methodology. (See *Clean Energy Orgs Push Entergy Players to Consider Broader Cost Allocation*.)

Doner said he expected the regional cost allocation directive of Order 1920 would be the most interesting portion of MISO's compliance.

MISO has until June 12, 2026, to comply with Order 1920. It plans to hold discussions on its Order 1920 compliance at upcoming Planning Advisory Committee meetings. ■

NYISO Details Proposed Metrics for IDing Poor Performers in Reserve Market

By Vincent Gabrielle

NYISO has *proposed* the metrics for identifying operating reserve suppliers that consistently underperform as part of its plan to remove them from the market.

The ISO first presented the proposal in January, but it had not yet specified the thresholds for determining whether a supplier was underperforming. (See *NYISO Explains How It Would Put Poorly Performing Resources in Time-out*.)

One metric is aimed at frequently called poor performers and examines how they performed during Reserve Pick-up (RPU) events — defined as when the area control error exceeds 100 MW — and audits.

The other targets those that are qualified to provide reserves but are rarely called to do so and examines their performance when dispatched in the energy market. "We're looking at their energy dispatch in the cases where they weren't picked up for an RPU but are still a provider," NYISO Associate Engineer Andy Bean told the Installed Capacity Working Group on April 24.

Bean explained that the first metric would be a snapshot of the last three months of RPU performance data. The ISO would divide the difference of the expected basepoint and energy provided by the total sum of the expected basepoints for the three months. Generators that fall below 70% of their expected performance would be subject to a rebuttable presumption of removal from the market.

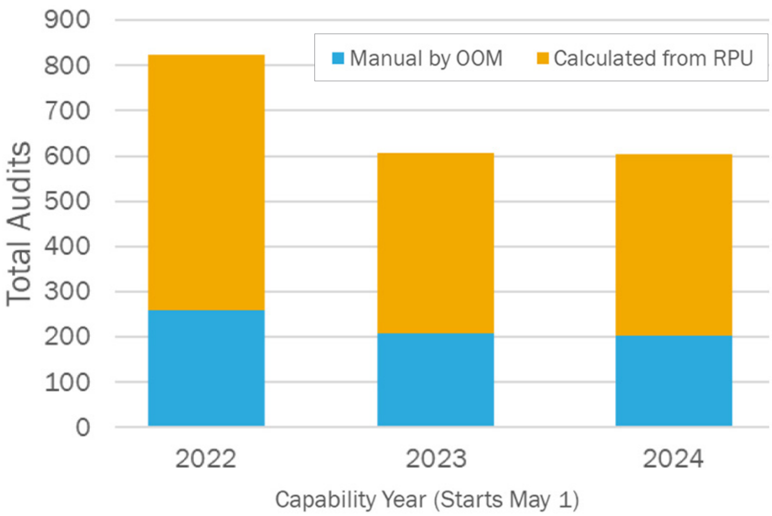
The metric would be applied any time a resource eligible to provide 10-minute operating reserves is dispatched during an RPU event and during manual audits of eligible resources.

The energy performance metric is structured similarly, but instead of comparing an expected basepoint to energy provided, it uses the same formula to compare energy requested to energy provided over the past three months. Bean said this metric would be assessed any time a resource in the operating reserves market is scheduled, but not when it is providing regulation. If energy performance falls below 50%, it would be subject to a rebuttable presumption of removal.

Resources that fail to meet these thresholds would be eligible for removal from the market for at least 30 days.

Richard Bratton, representing the Independent Power Producers of New York, asked how the ISO had come up with the thresholds.

Bean said NYISO staff had looked at historical data, and those percentages were where they saw "natural breaks" and the worst-performing units separating out. These units, Bean said, were also aligned with what the Market Monitoring Unit identified as the worst performers.



Operating reserve audits by capability year | *NYISO*

Why This Matters

The ISO has identified roughly 550 MW of operating reserves suppliers that would have failed to meet the ISO's proposed performance thresholds last year.

The ISO found that in 2024, roughly 550 MW of operating reserve suppliers would have failed one or both of the metrics and would have been subject to the threat of removal from the market. If all of them had been removed for three months, this would mean that operating reserves would be down 100 MW each month in 2024.

Bean presented a slide showing historical audit data, demonstrating that between the 2022 and 2024 capability years, there were about 80 audits stemming from RPU issues.

Resources may rebut the metrics by showing that the data are incorrect, they were in an outage or their basepoints are inconsistent with what they can provide. Extreme circumstances outside of operator control would also rebut the ISO's presumption that the resource was performing poorly.

If the resource is unable to rebut, they would be removed from the operating reserves market for 30 days in the first instance and 90 days in subsequent instances. The ISO would retest resources to allow them back on the market.

Mark Younger of Hudson Energy Economics, representing generators, asked whether there would be a mechanism for permanently removing a resource from the operating reserves market. Bean said that was currently not part of the proposal.

Bean said NYISO would consider stakeholder feedback before finalizing the metrics, mentioning several times that he had "starred" comments and questions in his notes over the course of the meeting. ■

NRECA Legislative Fly-in Focuses on Permitting, Meeting Demand

Co-op Execs Also Point to Tariff-driven Supply Chain Concerns

By James Downing

The National Rural Electric Cooperative Association (NRECA) has flown 2,000 member representatives to Washington, D.C., to lobby congressional leaders on key issues for the nation's co-ops, which this year include passage of permitting legislation and meeting rising energy demand.

"Our desire, as electric co-ops, is to make sure we have smart energy policies that help us meet this challenge, because it's a good challenge to me," NRECA CEO Jim Matheson said on a call with reporters kicking off the April 28-30 Legislative Conference. "I mean, growing electric demand is good news for our country. It shows our economy is growing, and that's what we want."

One of NRECA's key priorities is to get some changes to federal permitting passed, after a bipartisan effort to do so fell short in the last Congress. (See *Lame Duck Permitting Push Fails; Manchin Blames House GOP Leaders*.)

"I think there continues to be an understanding across a large segment of Congress, in a bipartisan way, that our permitting process is not functioning in the most efficient way, and so that's good," Matheson said. "On the other hand, we all know that [there's a] small margin in Congress and getting any type of legislation through can be a challenge."

One way the Republican majority is considering to get around the narrow margin is "reconciliation," since it avoids the Senate filibuster, but it can only be used to pass laws related to funding the government (Democrats used it to pass the Inflation Reduction Act in 2022).

But with so many laws implicated in federal permitting, Matheson said the issue will ultimately require a "multifactor effort from a legislative standpoint" to enact all the needed changes.

NRECA supports some of President Donald Trump's regulatory rollbacks at EPA because they will keep needed power plants running in a time of demand growth, but the administration's trade policies are presenting problems for that effort.

"The supply chain that serves the electricity sector in this country is a global supply chain. That's a fact," Matheson said. "And, so, the answer is, to the extent that the supply chain is disrupted or has additional costs associated with it based on tariffs, yes, that is going to have an impact on the electric sector in general, and on electric co-ops in particular."

The tariffs have proved to be moving targets, with President Trump often lowering or delaying them, but any disruptions or higher costs for needed equipment is ultimately going to impact the rural consumers NRECA members serve, he added.

The industry is still dealing with supply chain disruptions from the COVID-19 pandemic, and now any policy uncertainty is exacerbating the issue, said Keith Brooks, general manager of Douglas Electric Cooperative in Roseburg, Ore.

"We adjusted our inventory practices during COVID," Brooks said on the press call. "We're probably carrying twice as much inventory as we had in the past, just to ride out some of these supply chain ups and downs. But, you know, anything that makes the situation worse is a little scary for us."

However, the tariffs have not been in place long enough to have had a major impact on the power industry's supply chains yet, he added.

"We continue to be in a wait-and-see mode for any actual dollar impact to our members that will be the result of any tariffs that come through," said Annalisa Bloodworth, CEO of Oglethorpe Power, a 38-member co-op in Georgia. "We are starting to receive, from vendors across our supply chain, notices and alerts that their expectations are of increased costs and potential disruption."

That comes on top of a supply chain that is very much under pressure, not only from the supply side, but from the growing demand for power in the U.S. and around the world, Bloodworth added. ■

Why This Matters

The views expressed at the NRECA Legislative Conference represent the concerns of thousands of rural co-ops across the country.

The U.S. Capitol | *Shutterstock*

Coastal Virginia Offshore Wind Sees Costs Increase from Trump Tariffs

By James Downing

Dominion Energy's Coastal Virginia Offshore Wind (CVOW) project has weathered most of the issues facing offshore wind, but the company said during its first-quarter earnings call May 1 that the project faces risks from President Donald Trump's tariffs.

The project is 55% complete and months away from the first delivery of energy to customers in 2026, and it is still on track for 100% completion that year, Dominion CEO Robert Blue said.

"It represents the fastest and most economical way to deliver almost 3 GW of electricity to Virginia's grid to support America's AI and cyber preeminence and the largest data center market in the world; to support U.S. shipbuilding at customers like Huntington Ingalls — the largest military ship building company in the United States and one of our largest customers — and support some of the country's largest and most important military and defense installations," Blue said.

The project's components are being or already have been assembled, and Dominion has taken delivery on many already, with its Jones Act-compliant vessel, the *Charybdis*, nearly complete and heading to the construction site off the southern coast of Virginia in the next two months to support turbine installation this summer.

"It's difficult to fully assess the impact tariffs may have to the project's final cost, as actual costs incurred are dependent upon the tariff requirements and rates, if any, at the time of delivery of the specific component," Blue said.

So far, components have already cost an extra $4 million, of which Dominion is responsible for $1 million, but that could grow to as much as $510 million, with the firm responsible for $128 million. It has already filed updated costs with Virginia's State Corporation Commission that show a $123 million impact from tariffs and Dominion responsible for $31 million, with a final project cost estimate of $10.8 billion.

"The updated project cost of $10.8 billion is expected to increase residential customer bills by an average of 4 cents a month over the life of the project," Blue said.

Generally, the impact of tariffs on Dominion's business seems manageable, with Blue saying that it had already updated its supply-chain practices after the COVID-19 pandemic.

A picture from Dominion's earnings presentation of the nearly complete Jones Act-compliant ship Charybdis that will start working on CVOW this year. | *Dominion Energy*

Why This Matters

President Trump's tariffs are expected to cost Virginians 4 cents a month on their bills, as they have raised the prices for the components still being delivered for the Coastal Virginia Offshore Wind project.

"We think about increasing inventory and ordering thresholds to address longer lead times, ensure that we have multiple sources of supply where it's appropriate," Blue said. "We have been placing some orders ahead of tariff effective dates to mitigate cost increases where it's possible."

The other big issue facing Dominion is continued growth in Data Center Alley in Northern Virginia, the largest data center market in the world. Blue reported no slowdown of interest in adding new facilities to that market.

Dominion recently asked for a rate increase from the SCC, which also included a proposed new customer class for large loads like data centers that requires them to agree to pay for at least 14 years of power consumption, even if they use less. (See *Citing Inflation and Load Growth, Dominion asks Virginia for Higher Rates*.)

The new rate class applies to customers who use at least 25 MW, and it would apply to 139 separate consumers, of which 131 are data centers, Blue said. The changes are meant to ensure they pay their fair share and that other customers face less risks around stranded assets.

"We've talked with the data center customers," Blue said. "We talked with them in preparing this proposed new tariff. I'm sure there will be further conversations during the case, but I think I can say confidently they understand what we're looking to accomplish here, and the conversations have been very constructive." ■

PJM Selects 51 Projects for Expedited Interconnection Studies

Uprates Represent Largest Number, but New Projects Make up Greater Share of Capacity

By Devin Leith-Yessian

PJM has selected 51 projects to receive expedited interconnection studies through its Reliability Resource Initiative (RRI), adding 11,793 MW of nameplate capacity to the next study cycle.

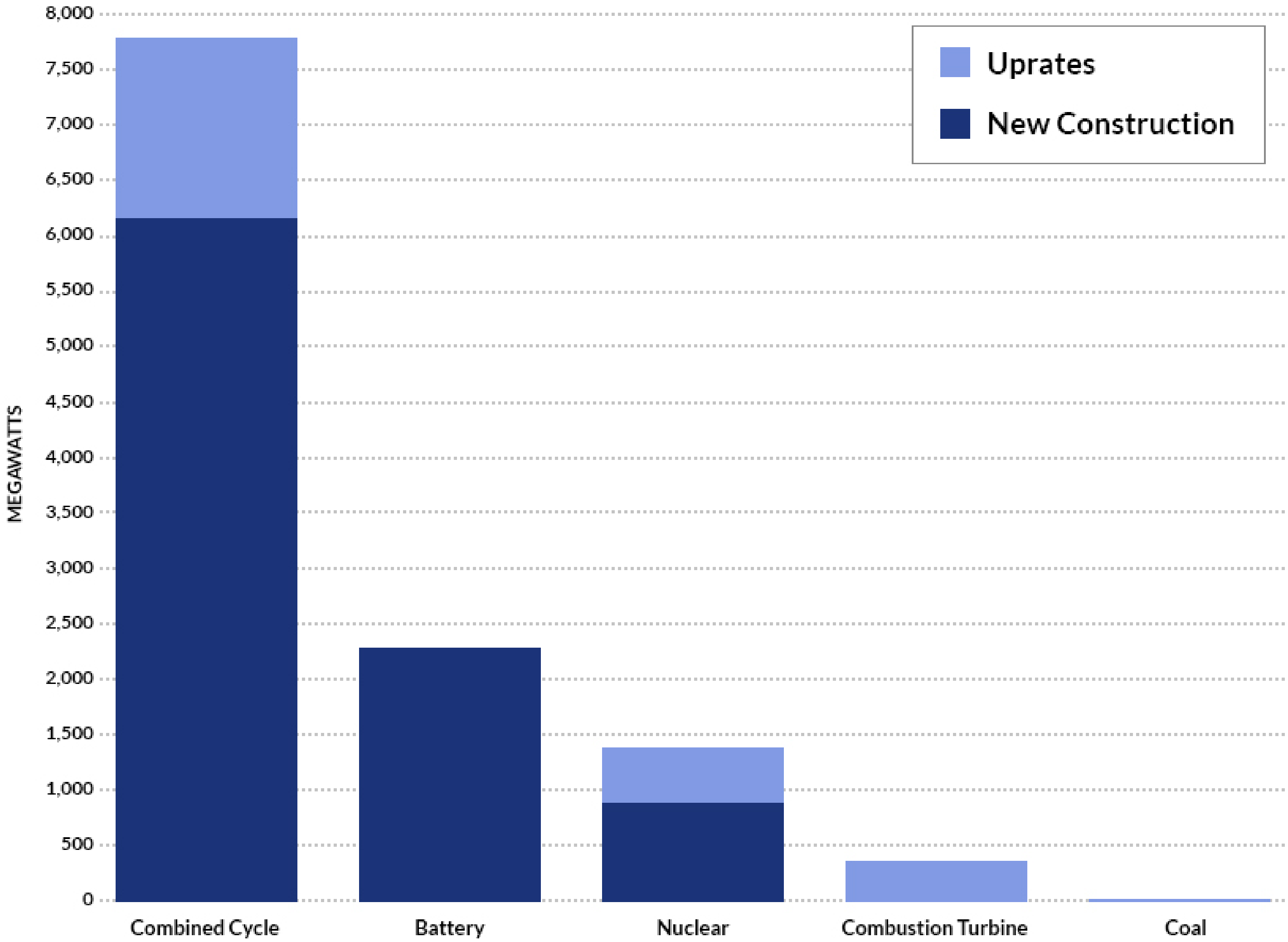
The RTO's May 2 *announcement* said 39 of the projects are uprates of existing units, amounting to 2,488 MW, while the bulk of the capacity comes from 12 "new construction" projects, which would bring 9,305 MW to market. That translates to 9,361 MW of unforced capacity (UCAP) split between 2,108 MW of uprates and 7,253 MW of new construction.

The majority of the additional nameplate comes from six new combined cycle gas generators and 20 uprates, which would together provide 7,756 MW if completed. An additional 2,275 MW of battery storage was selected, coming from five new projects. Four uprates to nuclear units would add 496 MW, while one new unit would carry 887 MW.

Thirteen combustion turbine uprates would provide 365 MW, and 14 MW would come from an uprate to a coal generator. One onshore wind project was selected to increase its capacity inter-

Why This Matters

PJM's Reliability Resource Initiative is meant to address a possible capacity shortfall in the 2029/30 delivery year by expediting interconnection studies on 51 projects that can rapidly add capacity to the grid.



PJM announced that it has selected nearly 12 GW of projects to receive expedited interconnection studies through its Reliability Resource Initiative, the majority of which would come from combined cycle gas generators. | © *RTO Insider* connection rights (CIRs) by around 20 MW.

FERC approved the initiative Feb. 11 to address a potential capacity deficiency PJM has identified in the 2029/30 delivery year. By ranking and selecting RRI applications according to their expected capacity contribution, in-service date and location, PJM argued that the one-time program could allow projects that could quickly bring additional capacity online to be added to Transition Cycle 2 (TC2).

By limiting the number of projects selected to 50, it said there would be no impact to other queue positions in the cycle; ultimately, 94 applications were received, amounting to 26.6 GW of nameplate. The May 2 announcement said 51 were selected due to a tie in the ranking. (See *PJM Receives 94 Applications for Expedited Interconnection Process*.)

PJM's announcement said 90% of the selected projects should begin service before 2030 and all should be able to come online by 2031.

'Thinly Veiled Effort'

Renewable developers and environmental organizations have objected to the RRI, characterizing it as allowing fossil fuel generation to jump a queue made up of mostly wind and solar projects.

"If PJM were serious about addressing reliability concerns, they would be complying with FERC's order to reform their interconnection process and speeding up their interconnection queue to get projects online that have been waiting for years. Instead, PJM has decided to let gas plants cut in line," Sierra Club Staff Attorney Megan Wachspress told *RTO Insider*.

Wachspress called RRI a "thinly veiled effort to move gas plants ahead of renewable resources" and said it is "beyond disappointing that more than 75% of the projects selected are methane gas projects when study after study [has] shown that renewable energy is more reliable, affordable and better for the environment."

She also said that winter storms Elliott and Uri showed that "gas plants underperform when families need electricity the most. Rather than follow FERC's direction to improve interconnection and transmission, PJM's short-sighted favoritism will put customers at risk and threaten our environment."

PJM highlighted several changes it's making to its interconnection study process, including the cluster-based study process, of which RRI is a part. Since being approved by FERC in 2022, PJM said, the process has completed studies on about 18 GW of projects, and studies on an additional 62 GW should be completed by the end of 2026.

The announcement also notes the commission has recently approved changes to PJM's surplus interconnection service (SIS), which allows expedited studies for new projects sharing a point of interconnection (POI) with an existing or planned resource not fully using its injection capability (*ER25-778*).

Another proposal before the commission would revise the process for transferring CIRs from a retiring generator to a replacement resource by allowing all resource classes to participate, most notably storage (*ER25-1128*). (See *PJM Stakeholders Approve SIS Manual Language*.)

Increased automation of studies could reduce the queue backlog by 60%, PJM said, pointing to a collaboration with Google announced April 10 to use AI tools to streamline the process. (See *PJM, Alphabet Partnering on AI Tools to Speed Interconnection*.)

In a statement, Constellation Energy said the Crane Clean Energy Center, formerly Three Mile Island, was among the projects selected. The company said the RRI allows high-reliability projects to respond to rising load forecasts fueled by burgeoning AI and manufacturing demand.

"In addition to Crane, PJM selected three Constellation 'uprate' projects that will increase output at three other nuclear plants in our fleet, bringing the total increase from the four projects to 1,150 MW of clean, firm electricity. We look forward to bringing these projects online to help support grid reliability and economic development throughout the region," the statement reads.

American Clean Power focused on the ability of storage developers to quickly install their selected projects, which improve grid reliability and reduce costs, ACP spokesperson Phil Sgro said in an email.

"The representation of energy storage in PJM's selection highlights these benefits, including favorable capacity accreditation and shorter development timelines," Sgro wrote. "To balance the strengths and weaknesses of all generation resources, a diversified grid that includes clean energy is the best way to achieve the most reliable and affordable grid. PJM has [forecast] annual demand growth of nearly 5% over the next 10 years. Renewable resources are quick to deploy and provide additional capacity for the grid, helping boost overall reliability and meet rising demand." ■

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ERO Insider

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SPP Addresses 3rd Load Shed Since March 31

By Tom Kleckner

OMAHA, Neb. — SPP staff have told its state regulators and board members that it will do better after three local load sheds since March 31.

The outages affected a combined 54,000 customers in northwestern Louisiana and mostly oil and gas facilities in southeastern New Mexico.

"They're concerning, and we are committed to analyzing what went wrong and what we need to do to get better," SPP CEO Lanny Nickell said May 5 during the Regional State Committee's quarterly meeting.

The most recent, and largest, load shed since Nickell became CEO came April 26 near Shreveport, La., in Southwestern Electric Power Co.'s (SWEPCO) service territory. SPP said it identified grid instability in the area and directed SWEPCO to immediately reduce its electricity use by 140 MW, resulting in a six-hour outage for about 30,000 residential customers in Caddo and Bossier Parish.

Bruce Rew, SPP | © RTO Insider

Bruce Rew, SPP's senior vice president of operations, told the RSC and stakeholders that temperatures came in higher than forecast, increasing load. With several generators and transmission lines out for planned maintenance, the grid operator didn't have enough generation to respond to voltage instability in the area.

Coming as it did three weeks after a similar event, the outage generated numerous headlines in the region:

- *La. Commissioner calls power outage 'unacceptable,' SWEPCO and SPP respond*
- *What caused SWEPCO's weekend power outage in Shreveport-Bossier and will it happen again?*
- *The unbelievable excuse for the Bossier Parish SWEPCO power outage: 'maintenance'*

Foster Campbell, the outspoken Louisiana commissioner who serves northern Louisiana and once ripped SPP for its "Taj Mahal" of a headquarters building, held a press conference in his office April 29. (See *Louisiana's Campbell Expands Beef with SPP*.)

Campbell called Nickell and SWEPCO President Brett Mattison and sat them alongside him, where they held court before the regional media for about an hour. One image from the press conference showed Nickell, his head bowed, listening to Campbell as the commissioner looked at the CEO and pointed to a document.

Nickell noted to the RSC that the event occurred during a pleasant spring afternoon.

"What I found is there's never a good time to take an outage. There's never a good time to interrupt service," he said. "It's important that we never take for granted what we do to keep the lights on."

Campbell has asked SPP and SWEPCO staff to attend the Public Service Commission's next meeting and discuss compensation for the outage's damage. SPP has said it will have representatives at the meeting.

"Let's see about how we can get together and how much money would be reasonable or fair," Campbell said during the press conference. "We're going to work this out and come up with a solution. We gotta figure out how you give these people their money back that lost its revenues while the power was down."

Why This Matters

SPP has been forced to drop load three times since March 31, affected a combined 54,000 customers in Northwest Louisiana and some industrial facilities in New Mexico. The grid operator says the outages are 'concerning' and that it is analyzing what went wrong and what it needs to do better.

SPP CEO Lanny Nickell (left) addresses the media as Louisiana Public Service Commissioner Foster Campbell listens. | *KSLA News 12*

The RTO has said it will work with SWEPCO to conduct a comprehensive analysis of the event to understand what happened and determine future actions.

"We will consider all possible solutions to issues that threaten real-time and long-term reliability across the region we serve," SPP said in a *statement*.

The Shreveport area also went through an emergency outage April 2 after a dangerous storm system swept across the Midwest. More than 24,000 customers were without power for several hours. SWEPCO said it was required by SPP to implement "emergency grid protection outages" to prevent "potentially catastrophic damage" to the grid.

A SWEPCO representative told one of the regional media outlets that emergency outages like the April 2 event are "incredibly rare" and not something that happens regularly.

The third load shed took place March 31 in Southwestern Public Service Co.'s (SPS) eastern New Mexico service territory, which has dealt with slim generation margins recently, Rew said. Several generators were out of service for planned maintenance or forced outages, and when there was a steep drop in wind production during the early morning, the reliability coordinator ordered SPS to drop 122 MW of load.

The outage affected primarily large industrial consumers and lasted less than three hours before offline generation could be deployed. ■

Company Briefs

Woodside Commits $17.5B to LNG Facility

Australian energy company Woodside last week announced it will spend $17.5 billion on a new LNG facility in Louisiana.

Once operational in 2029, Louisiana LNG will produce up to 16.5 million metric tons of LNG per year.

Climate advocates said the announcement will put further pressure on the company after a major rebuke from shareholders last year over its emissions plan. The facility would add about 1.6 billion tons of greenhouse emissions over its 40-year life.

More: *The Guardian*; *10/12 Industry Report*

Boviet Opens First U.S. Solar Factory in North Carolina

Vietnamese solar panel maker Boviet Solar has opened the doors to its first U.S. module plant in Greenville, North Carolina.

The company invested $294 million in the facility, which will produce Boviet's Gamma Series monofacial and Vega Series bifacial solar panels. The first phase is now online, with an annual PV module output capacity of 2 GW. For Phase 2, which is scheduled to come online in the second half of 2026, Boviet will invest another $100 million to add 600,000 square feet and ramp up to another 2 GW.

More: *Electrek*

EVP Moeller Leaving EEI

The Edison Electric Institute (EEI) last week announced that Executive Vice President Phil Moeller will step down later in May.

Moeller joined EEI after serving two terms as a FERC commissioner, where he was nominated by President George W. Bush and reappointed by President Barack Obama.

More: *EEI*

Southern Co. Reports $1.3B in Earnings in Q1

Southern Company last week reported first-quarter earnings of $1.3 billion in 2025, compared to $1.1 billion in the first quarter of 2024.

First-quarter 2025 operating revenues were $7.8 billion — an increase of 17% from last year.

More: *Southern Company*

Federal Briefs

House Votes to Overturn California Clean Truck Rules

The House of Representatives last week voted to overturn the Biden administration's approval of California's clean truck rules.

One of the truck rules the House voted to overturn explicitly seeks to make more trucks electric, while the other seeks to limit emissions of nitrogen oxides. The measures passed 231-191 and 225-196.

The House nixed the rules using the Congressional Review Act. The act allows Congress, with just a simple majority in both chambers and presidential approval, to reverse recent regulations.

More: *The Hill*

Senate Passes Bill to Repeal Biden-era Appliance Standards

The Senate last week voted 52-46 to pass a joint resolution repealing the Biden administration's rule for establishing energy conservation standards for appliances.

The resolution, which passed the House in March, would nullify the Energy Conservation Program for Appliance Standards' certification requirements. It would apply to 20 household and commercial products, including dishwashers, central air conditioners and washers.

More: *The Hill*

Senate Overturns EPA Rule on Toxic Air Pollutants

The Senate last week voted 52-46 to overturn an EPA rule limiting the seven most hazardous air pollutants emitted by chemical plants, oil refineries and other industrial facilities.

The rule dictates that once a facility emits any of the seven toxic air pollutants at unsafe levels, it must always maintain strict pollution controls, even if its emissions later drop to safe levels. According to analysis by Earthjustice, the regulation has compelled more than 1,800 facilities nationwide to curb their pollution.

It marks the first time in the Clean Air Act's 55-year history that Congress has scaled back protections under the law.

More: *The Washington Post*

EPA Canceling Nearly 800 Environmental Justice Grants

EPA plans to cancel 781 grants issued under President Joe Biden, EPA lawyers wrote in a court filing last week, almost twice the number previously reported.

The filing in *Woonasquatucket River Watershed Council v. Department of Agriculture* marks the first time the agency has publicly acknowledged the total number of grants set for termination, which includes all its environmental justice grants. The grants would have funded a range of projects aimed at helping communities cope with the effects of climate change.

More: *The Washington Post*

State Briefs

CONNECTICUT

House Approves Goal to Reach Net-zero Emissions by 2050

The state House of Representatives last week voted 98-47 to approve a bill that aims to have net-zero carbon emissions throughout the economy by 2050.

The legislation would strengthen the state's existing carbon-reduction goals and create a new "Clean Economy Council" to develop strategies and policies to help meet those targets. Under current law, Connecticut has pledged to reduce its greenhouse emissions by 80% between 2001 and 2050.

The bill now heads to the Senate.

More: *CT Mirror*

DELAWARE

Gov. Meyer Aims to Eliminate State's EV Mandate

Gov. **Matt Meyer** last week said he will eliminate the state's mandate to sell a certain number of EVs.

Former Gov. John Carney in 2023 enacted a mandate that required dealerships to offer increasing percentages of either fully electric or plug-in hybrid electric vehicles.

Meyer said he believes people "should have a choice over what they want to buy, and sellers should have a considerable choice on what they want to sell."

More: *WHYY*

MARYLAND

SmartEnergy Ordered to Pay $6.5M in Refunds

The Public Service Commission last week ordered $6.5 million in refunds to more than 32,000 former customers of SmartEnergy Holdings.

The decision came after the commission concluded that the New York City-based renewable energy supplier misled and deceived customers and violated a state law. The company has 90 days to refund its customers who enrolled by telephone between February 2017 and May 2019.

More: *The Baltimore Banner*

State Supreme Court to Hear Climate Change Cases

The state Supreme Court last week said it will decide whether three climate change lawsuits are preempted by federal law.

The high court granted review of Baltimore City, Annapolis and Anne Arundel County's lawsuits against more than two dozen fossil fuel companies, agreeing to hear issues in a consolidated appeal that was previously rejected by federal courts. The court will decide four issues from the appellants' petition, including whether the U.S. Constitution and federal law preempt and preclude state law claims seeking redress for injuries allegedly caused by the effects of out-of-state and international greenhouse gas emissions on the global climate.

More: *The Daily Record*

NORTH CAROLINA

Treasurer Names van der Vaart to Utilities Commission

Treasurer Brad Briner last week appointed Donald van der Vaart to the Utilities Commission.

Van der Vaart begin his career in state government in the Division of Air Quality and was promoted to secretary of the Department of Environmental Quality by Gov. Pat McCrory in 2015. He was a proponent of offshore drilling and fracking.

The appointment still must be approved by the state House and Senate.

More: *Inside Climate News*

OHIO

Lawmakers Pass Bill Ending Ratepayer Charges from HB6

State lawmakers last week voted to end the subsidy for two unprofitable coal plants that had cost ratepayers nearly $400,000 a day, after they were tucked into House Bill 6 at the center of the largest corruption scandal in state history.

The bill would put an immediate end to the "legacy generation rider" for the two Ohio Valley Electric Corp. plants contained in HB6. The bill also requires utilities to routinely come in for rate cases and justify how they spend ratepayer-collected money; creates a school energy efficiency loan program to reduce energy costs for public schools; and codifies that consumers must receive refunds for improper charges.

The bill goes to Gov. Mike DeWine.

More: *The Associated Press*

Supreme Court Approves Licking County Solar Project

The state Supreme Court last week affirmed the Power Siting Board's 2022 decision to grant the 350-MW Harvey Solar Project a certificate of environmental compatibility and public need.

Citizens group Save Hartford Township argued the developer didn't evaluate the "economic disadvantage" of solar and didn't conduct a proper study on possible night noise generated by the project, among other allegations. However, the justices ruled that the residents opposing the facility failed to prove the board acted unlawfully or unreasonably.

The project is expected to take 18 to 24 months to build.

More: *WOSU*

SOUTH CAROLINA

Santee Cooper Enacts Higher Rates for Data Centers, Large Users

Santee Cooper's governing board voted unanimously to implement a new rate for large, incoming customers on an "experimental" four-year basis.

The special rate would apply to any customer requiring 50 MW or more. The rates will also go into effect no matter what the state Legislature decides on incentives for data centers.

More: *South Carolina Daily Gazette*

VIRGINIA

Dominion Seeks Approval for Data Center Infrastructure

Dominion Energy last week filed a plan with the State Corporation Commission to build high-voltage lines to support a data center.

Dominion said it wants to build the lines in western Chesterfield County in large part to serve a planned hyperscale data center, along with the substations and safety equipment needed to direct the right voltages to the right places. The cost of the plan is an estimated $121 million.

The company hopes to begin construction in February 2027, if the SCC approves the project, and complete the project by June 2028.

More: *Richmond Times-Dispatch*

Mecklenburg Rejects Antlers Road Solar Project Again

The Mecklenburg County Planning Commission last week voted 11-1 to reject the proposed 90-MW Antlers Road Solar project for a second time.

RWE Renewables Americas previously sought the county's approval for the project in 2022 but was told it was not in compliance with the county's comprehensive plan. This time the commission said the project was not in compliance with the county's plan because it would destroy prime farmland and threaten the nearby watershed.

A final decision will be made by the county Board of Supervisors.

More: *Mecklenburg Sun*

WEST VIRGINIA

Appalachian Power Requests $71M for Fuel Costs

Appalachian Power and Wheeling Power last week submitted their annual Expanded Net Energy Cost (ENEC) to the Public Service Commission.

Within the filing, the company requested $71.6 million to pay for fuel for customers at cost. It said if the amount is included in the currently pending securitization filing and approved, a need for an ENEC increase would be reduced significantly.

The average residential bill would increase by $5.31 in September if the ENEC is approved as filed and not included in the securitization amount.

More: *WV Metro News*