ISSN 2377-8016 : Volume 2025/Issue 25 ▪ June 24, 2025

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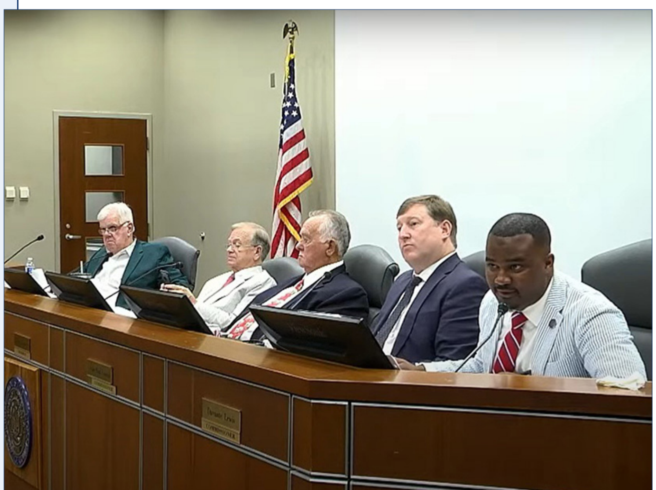
MISO

MISO Debates What-ifs, Vows Improvements in Front of La. PSC After Load Shed



La. PSC

Once again, MISO leadership said the late May blackouts in New Orleans are likely a catalyst for the RTO creating a transmission emergency warning system in addition to its existing capacity emergency warnings. Louisiana state commissioners rebuked MISO for providing notice only mere minutes before directing load shed.

CONTINUED ON P.28

ISO-NE

ISO-NE

ISO-NE CEO Gordon van Welie Announces Retirement (p.24)

Van Welie's planned exit comes during a period of significant change at the RTO, and incoming CEO Vamsi Chadalavada will be tasked with juggling challenges related to load growth, the integration of renewables, and increasing conflicts between federal and state policy.

CAISO/WEST

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Industry Sees Challenges as BPA Considers 'Radical' Updates to Transmission Planning (p.6)

With 65 GW of transmission service requests, BPA has said the region needs 'radical' reforms in order to keep up.

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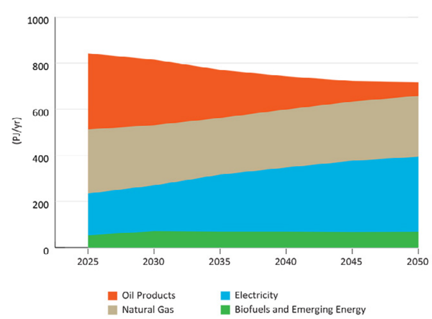

Ontario Ministry of Energy & Mines

Ontario Integrated Energy Plan Boosts Gas, Nukes (p.17)

The province's first-ever integrated energy plan seeks to ensure sufficient capacity for a forecast 75% increase in electric demand over the next 25 years.

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In this week's issue

DOE's Wright Fields Senate Questions About Funded Project Reviews

Energy Secretary Claims Process Will not be 'Political'

By James Downing

Senators had a chance to ask Energy Secretary Chris Wright about project spending his department has put under review — or already cut — when he testified at the Senate Energy and Natural Resources Committee about the Trump administration's 2026 budget request.

"It is deeply concerning how many billions of dollars were rushed out the door without proper due diligence in the final days of the Biden administration," Wright said during his June 18 testimony. "DOE is undertaking a thorough review of financial assistance that identifies waste of taxpayer dollars, protects America's national security and advances President Trump's commitment to unleash American energy dominance."

He said that led DOE to terminate 24 projects totaling $3.7 billion in spending that failed to meet the economic, national security or energy security standards needed to sustain the agency's investment.

Ranking Member Martin Heinrich (D-N.M.) said those deals were canceled without notice or justification and that DOE crossed into "impoundment territory," which is when the executive branch cancels congressionally approved funds, an act only legal in narrow circumstances.

"Actions like these will severely damage our country's ability to lead in developing and commercializing next generation technologies while ceding ground to our competitors," Heinreich said.

Sen. Steve Daines (R-Mont.) asked about the North Plains Connector transmission project, which would run through his state and connect the Eastern and Western interconnections. Last summer it was awarded funds under the Grid Resilience and Innovation Partnership (GRIP). (See *DOE Announces $2.2B in Grid Resilience, Innovation Awards*.)

Why This Matters

Senators from both sides of the aisle expressed concern that Trump's DOE could cut funded projects considered valuable to their regions.

Energy Secretary Chris Wright | *DOE*

The project would open new markets to the Colstrip power plant, which currently is linked to utilities in Oregon and Washington, Daines said.

"This project would have the potential to diversify Montana's generation assets, unlocking billions in private investment and enhance our nation's energy security by connecting the Eastern and Western Electric grids," he said.

Wright said he has met with the North Plains Connector's developer previously and called the project — and the general idea of increasing transfer capability across the two interconnectors, a good idea.

"We are committed to following this project review process where a crew of people evaluate — not political, not biased for this or that," Wright said. "Just look at the math, look at the numbers, and is this thing viable and beneficial for America. You know, yes, no or adjustable — it's modifiable. So, we haven't finished that on that project yet, but I think you make a strong case for the project."

'Demand and Pressure'

Sen. Angus King (I-Maine) noted that GRIP funding was approved under the bipartisan Infrastructure Investment and Jobs Act, and not the Inflation Reduction Act, which is much more unpopular with Republicans. He asked whether the DOE's review of projects will be fair.

"We're evaluating the engineering, the science, the finance and just the viability of the projects," Wright said. "It is just a business review. Unfortunately, it wasn't done before when grants were given. But I would say, in the GRIP program, there's a lot of very good projects there."

King then asked about a major energy storage project being built north of Bangor, Maine, by Form Energy, which is under review by DOE currently. (See: *Form Energy to Develop First Multiday Storage Project in New England*.)

"We stood up this process a few weeks ago," Wright said, adding that the agency expects to do at least 20 reviews a week and telling King that he's "very interested" in storage as well. "My chief of staff here is here with me, and we'll make sure that in the next few weeks at most, we will get on to that project."

King additionally said he didn't understand why the Grid Deployment Office is facing a 75% cut in funding under DOE's budget request, given the "demand and pressure" on the grid.

Wright said he thinks DOE's most important grid-related offices are the Office of Electricity and the Office of Cybersecurity, Energy Security and Emergency Response. The budget cuts to GDO are part of a reorganization that will refocus its work in the Office of Electricity.

King said he hoped the funds earmarked to strengthen the grid are not slashed in the face of rising demand and more expensive power bills for consumers.

"One of the things I've noticed just in my career in energy is it used to be that the principal part of your electric bill was the cost of energy," King said. "Now, in many places, transmission and distribution is 50% or more, and that's only going to increase, unless we start to think about new technologies, what are called GETs, which I'm sure you're familiar with — grid enhancing technology, so that we're not simply rebuilding massive facilities that could be obviated by new technologies." ■

Lazard: Solar and Wind Retain Lowest LCOEs

Annual Report Backs Renewable Generation but Says Changes are Expected

By John Cropley

Lazard's latest analysis of the levelized costs of energy concludes that wind and solar are the least expensive new-build power generation for the 10th year in a row.

The LCOE of new gas-fired generation, meanwhile, has hit a 10-year high, and shortages of equipment are expected to drive further steep increases. However, existing baseload generation is increasingly competitive with new renewables, which have seen recent increases in their own LCOEs.

Still other factors have dropped the 2025 levelized cost of battery energy storage systems to their 2020 level.

Lazard issued the *18th edition* of its "*Levelized Cost of Energy+*" report June 16.

The financial advisory firm noted the report is a present-day snapshot based on the last 12 months in the U.S. power industry, rather than a prediction of future trends.

"Significant shifts expected" is what the report offers by way of predictions. Supply chain normalization and productivity enhancements could offset the rising LCOE of gas-fired generation over the longer term, for example, and expensive nuclear construction is poised to benefit from scale and development efficiencies.

Lazard also notes that other cost factors are shifting: Several grid operators are refining their capacity accreditation methodologies to incorporate the seasonal adjustments and diversity benefits of the increasing amount of renewable generation. This could significantly impact future firming costs, the report said.

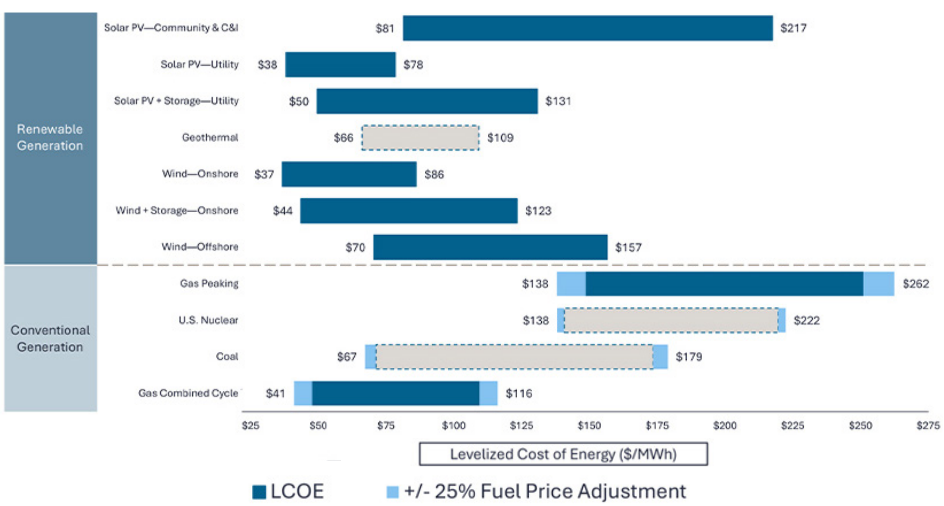
There is no single cost offered for a given type of generation — the LCOEs sprawl across a wide range that grows even wider as variables are factored in.

Utility-scale photovoltaics, for example, run $38/MWh to $78/MWh. That falls to $20-$45/MWh if investment tax credits, production tax credits and economic community adders are factored in, and it jumps to $50-$131/MWh if storage is added and there are no tax credits — a scenario that may come to pass soon. (See *Senate Finance Committee Looks to Eliminate Energy Tax Credits in 2028*.)

New onshore wind without storage and without tax credits would have an LCOE estimated at $37-$86/MWh.

By comparison, a combined-cycle gas-burning plant runs $48-$107/MWh, or $41-$116/MWh factoring in 25% fuel price adjustments lower and higher. Adding a carbon price of $40-$60/ton, as some policymakers have proposed, would bump its LCOE to $63-$132/MWh.

Cost of capital is another key factor, and here again there is no single formula, because each type of generation has a different risk vs. return profile, and their costs rise or fall at different rates.



Lazard's 2025 report on the levelized cost of energy breaks down the economics of multiple forms of power generation under various scenarios. | *Lazard*

Why This Matters

The cost of building and operating new generation assets is rising as the expected need for electricity grows.

One unsurprising detail: Existing paid-for assets have a lower LCOE than newly built assets. The marginal cost of operation can drop as low as $24/MWh for a fully depreciated combined-cycle gas plant, for example, or just half the lowest calculated LCOE of a new gas plant.

The report calculates the most expensive type of generation would be a newly built peaker plant burning gas at a cost of $3.45/MMBtu. With a capacity factor of 10-15%, its LCOE would be in the range of $149-$251/MWh.

Lazard notes that renewables have grown into an established industry constituting 20% of the U.S. electrical system in the time it has been compiling its LCOE reports.

Data from its current and past reports show concurrent changes in LCOE: Utility-scale solar dropped from $359/MWh in the 2009 report to $58/MWh in 2025, while onshore wind dropped from $135/MWh to $61/MWh.

The data also show those 2025 LCOEs are significantly higher than in the 2021 report, when utility-scale solar and onshore wind bottomed out at just $36/MWh and $38/MWh, respectively.

Battery energy storage system prices are moving slightly in the opposite direction. Lazard places the 2025 levelized cost of storage for a 100-MW four-hour utility-scale standalone BESS at $115-$254/MWh, sharply lower than 2024 and slightly lower than 2020.

It attributes this to market factors, such as slower than expected electric vehicle demand and a resulting oversupply of cells, as well as to advances in technology like increased cell capacity and energy density. ■

FERC Issues Guidance to Comply with Trump Order on Criminal Referrals

By James Downing

FERC issued a notice saying it would coordinate with the attorney general on what crimes it would refer to the Department of Justice for criminal prosecution (*AD25-12*).

The commission said June 16 it will work with DOJ to file a report with the White House's Office of Management and Budget that lists all criminal regulatory offenses enforceable by the two, along with the range of potential criminal penalties and the applicable *mens rea* (guilty mind) standard for a violation. The report is due by May 9, 2026.

The notice was in response to President Donald Trump's *executive order* May 9 called "Fighting Overcriminalization in Federal Regulations." The order said that many of the regulations issued by the federal government carried criminal risk for violations.

"The situation has become so dire that no one — likely including those charged with enforcing our criminal laws at the Department of Justice — knows how many separate criminal offenses are contained in the Code of Federal Regulations, with at least one source estimating hundreds of thousands of such crimes," Trump said. "Many of these regulatory crimes are 'strict liability' offenses, meaning that citizens need not have a guilty mental state to be convicted of a crime."

FERC said its current policy is largely already in line with what Trump ordered. The commission only has authority for civil fines when companies or individuals violate its rules, but since gaining its enforcement powers under the Energy Policy Act of 2005, it *has said* it would refer activity to the department if the misconduct were serious enough and if parties exhibit "evidence of willful behavior."

The notice also announced a general policy that when FERC does make criminal referrals, it will consider the risk of harm caused by the offense, the potential gain to the defendant, whether the defendant had specialized knowledge or was licensed in the industry at issue, and what evidence is available of the defendant's general awareness of the lawfulness as well as their knowledge of the regulation at issue.

Trump directed agencies to work with the attorney general to determine whether they have the authority to establish a *mens rea* standard for its regulations.

"If consistent with the statutory authorities identified pursuant to the review described in subsection (a) of this section, the report should present a plan for changing the applicable *mens rea* standards and adopting a generally applicable background *mens rea* standard, and provide a justification for each criminal regulatory offense for which the agency proposes to deviate from its default *mens rea* standard," the order said. ■

FERC headquarters in D.C. | © RTO Insider

Industry Sees Challenges as BPA Considers 'Radical' Updates to Transmission Planning

By Henrik Nilsson

Why This Matters

With 65 GW of transmission service requests, BPA has said the region needs 'radical' reforms in order to keep up.

The Bonneville Power Administration faces monumental challenges in implementing actions to meet the Pacific Northwest's needs once it lifts its pause on transmission planning, multiple stakeholders told *RTO Insider*.

BPA issued the pause in February to consider new "reforms" in light of "exponential growth" of transmission service requests. The agency's 2025 transmission cluster study includes over 65 GW of requests, compared with 5.9 GW in 2021. The requests exceed the total regional load projected for the Pacific Northwest in 2034, according to the agency. (See *BPA Halts Some Tx Planning Processes Amid Surge of Service Requests*.)

To deal with the demand, BPA Administrator John Hairston has set ambitious goals for the agency. In a recent keynote address at the Western Conference of Public Service Commissioners' annual meeting, Hairston noted that much of the challenge stems from planning "around prospective data centers or generators that may never come to fruition."

Hairston said the agency sees the need for a "new planning paradigm." It is "rethinking" its transmission planning processes and working with its utility customers to identify new approaches by the end of the year. (See *Industry Needs 'New Planning Paradigm,' BPA Chief Tells Regulators*.) Ultimately, Hairston wants to reduce the time from transmission request to service to five to six years.

In an email to *RTO Insider*, BPA spokesperson Nick Quinata said the agency "has committed to considering radical new methods to reduce the time it takes to enhance infrastructure to accommodate its customers' needs."

BPA will provide more information on its timeline and proposed solutions at a workshop in July.

A New Approach

But analyzing 65 GW is "impossible," Randy Hardy, the agency's administrator from 1991 to 1997, told *RTO Insider*.

"They've got to somehow define a set of rules that will give them a more realistic ability to analyze whatever subset of the 65 GW they deem appropriate," Hardy said.

Much of the issue stems from aggressive clean energy legislation passed in Washington and Oregon in 2019 and 2021, respectively. The laws set strict standards for greenhouse gas emissions and ushered the region into a "gold rush" among developers, eventually leading to today's situation, according to Hardy. (See *Clean Energy, Equity Goals to Reshape Oregon IRP Process* and *Washington Agencies Adopt New Rules to Implement CETA*.)

Even though not every project will be completed, BPA must assume the opposite when analyzing them, Hardy said.

"The cumulative costs associated with building all that transmission means that the expenses of any particular transmission service request are enormous," he added.

He noted the 2023 cluster study included approximately 17 GW. The challenges with 65 GW are greater, and "even if you could analyze it, the cost would be so ridiculously high that nobody would sign up for anything."

BPA must depart from the principle of first come, first serve when taking on requests, Hardy said.

The agency is "not regulated technically by FERC … but they've made a policy commitment to align themselves as closely as they can to the FERC *pro forma* tariff," Hardy said. "They're probably going to have to loosen that to some extent, because first come, first serve is not going to allow them to resolve this. They've got to be able to exercise some engineering judgment of the transmission service requests that are filed as to which ones look the most promising."

Because FERC does not regulate BPA, the agency can and should take "bold steps" to clear up the transmission queue, Nicole Hughes, executive director at Renewable Northwest, told *RTO Insider*.

BPA should use its power to "wean out" speculative projects that are unlikely to get built. The challenge is to clear the queue equitably, Hughes said.

"We want to make sure that generation and load are being treated equitably and that load doesn't take a higher priority here," according to Hughes. "We want to make sure that the point-to-point customers are being treated equitably and the network customers aren't being prioritized here."

BPA has allowed other issues to take priority, like long-term contracts and its day-ahead market process, and the agency is now in "panic mode," Hughes said. (See *BPA Flooded with Comments on Draft Day-ahead Market Decision*.)

Proactivity

Renewable Northwest has been a supporter of BPA taking a more proactive approach to transmission planning, Hughes said. She pointed to the Western Transmission Expansion Coalition (WestTEC), which is jointly facilitated by the Western Power Pool and WECC, as an example. (See *WestTEC Tx Study on Track Despite Delays*.)

WestTEC's goal is to produce an actionable study to inform Western grid planning over 10- and 20-year planning horizons. Hughes said it's unclear what BPA will do with the information coming out of the WestTEC process, saying "that's still to be decided."

Henry Tilghman, a consultant whose clients include Renewable Northwest and the Northwest & Intermountain Power Producers Coalition (NIPPC), said there is a disconnect between the development time frames for different types of facilities that need to be addressed. (Tilghman spoke with *RTO Insider* on his own behalf, not that of his clients.)

"You can bring a new gas plant or renewable generator online in 18 months once you have all of your permits and the financing in place," Tilghman said. "The construction time can be a year and a half. Same for a data center. But if you're looking at a new transmission expansion with all of the siting and permitting and everything, that … takes at least 10 years to do. …

"I think a lot of the problems that the region is facing that Bonneville is attempting to solve stem from really just sort of an inadequate regional planning process," Tilghman added. "Even if we get it fixed … through Order 1920 compliance, we're still catching up on all that planning work that could have been done and hasn't been done."

According to Lauren Tenney Denison, director of market policy and grid strategy at the Public Power Council (PPC), BPA is considering moving toward proactive planning as a possible solution.

"The cost and risk discussion is going to be a really important one throughout this process," Denison said. "Building ahead of time, doing this proactive building that BPA is talking about, it has the ability to get us ready for future needs. But there is a cost to that, and so it's just a challenging issue that we will need to address with the region as we work through this."

Other challenges include the time it takes to build new transmission, a scarce labor pool and an arduous permitting process, PPC CEO Scott Simms said. For example, crossing state lines and different jurisdictions and federal agencies bring a host of bureaucratic headaches for developers, he said.

"We've seen proposals where segments of a line are approved and then they have a window, but there's approval pending somewhere else, and then the original approval expires while the new ones being granted," Simms said. "That's just paperwork that can be easily revamped and removed."

With a Little Help from Customers

There are opportunities for BPA customers to assist in developing transmission infrastructure, something Simms hopes will get fast tracked as the agency considers planning changes.

He said BPA appears willing to "engage or explore some disruptive elements that we haven't done before."

"We think that category includes the element of how customers of BPA can help shoulder some of that burden in order to make the regional objectives get achieved more quickly," he added.

The PPC has support for this idea from NIPPC Executive Director Spencer Gray, among others.

"Bonneville has had, and does have, a pretty restrictive approach to outsourcing some of the grid upgrade work to customers," Gray said. "We're hoping that that can change. That feels like really low-hanging fruit. I think the place that's most relevant is for network upgrades for interconnection customers. Both generators and load."

There is an opportunity to leave more of the building to customers in the *pro forma* Open Access Transmission Tariff, according to Gray.

"We really think there's room to liberalize that self-build option in the Northwest on Bonneville's grid," Gray said. Allowing a customer to either build themselves or contract out some of the work "would alleviate a lot of the burden on Bonneville itself to pull off some of these upgrades" and let the agency focus on "transmission service-driven upgrades rather than interconnection."

Aaron Tinjum, vice president of energy for the Data Center Coalition, told *RTO Insider* in a statement that data center companies "are leaning in as engaged partners across the country to ensure we meet this moment in a way that supports both data center development and an affordable, reliable electricity grid for all customers."

The industry is "committed to paying the full cost of service for the energy it uses, including transmission costs," he said.

Workforce Challenges

Other reforms are needed to meet Hairston's five-to-six-year timeline. A crucial one is allowing BPA to competitively pay staff. There's a big pay gap between BPA and consumer- and investor-owned utilities, Gray said.

"Any entity of comparable size to Bonneville in terms of asset, ownership, operating revenue, circuit miles of transmission

Bonneville Dam | © *RTO Insider*

… they just pay more," Gray added. "And if we're going to keep good staff, new talented ones, we really need to get [BPA] competitive pay authority so [BPA] can compete in the market for personnel."

The bipartisan Reliability for Ratepayers Act, passed by the U.S. House of Representatives on Jan. 15, aims to address this issue. Still, stakeholders told *RTO Insider* recent federal staffing cuts and "deferred resignation" buyout offers from President Donald Trump's unofficial Department of Government Efficiency have caused significant disruptions and risk shaking morale at BPA.

About 200 agency employees — or 6% of the workforce — accepted the buyout offer, while 90 job offers had been rescinded following a federal hiring freeze announced Jan. 20, according to BPA.

U.S. Energy Secretary Chris Wright has said BPA will not undergo more staffing cuts as part of Trump's quest to slim down the federal government. BPA's federal workforce now stands at around 3,150 employees, Hairston said during the agency's quarterly business review May 15. (See *BPA Exempted from Federal Staffing Cuts, Hairston Says*.)

Whether BPA can meet the five- to six-year goal hinges on a sufficient workforce and the lifting of the federal hiring freeze, former Administrator Hardy said. He put the odds of accomplishing the goal at 50/50.

"They're stuck with being down 200 positions when they actually need more than the 200 positions to be able to have sufficient staff to get them to a 90% or 80% level of confidence that they can accomplish all this stuff," according to Hardy. "So can it be done? Maybe, but it is a huge, huge challenge given the staffing restrictions that they're now subject to under the Trump administration." ■

Panel Ponders Impacts, Priorities Around Western Market Seams

Regional Issues Forum Touches on Risks of Breaking up CAISO's WEIM

By Elaine Goodman

RENO, Nev. — The formation of two competing day-ahead markets will create seams across the West, but at least one utility representative is more worried about seams resulting from the fracture of CAISO's real-time Western Energy Imbalance Market.

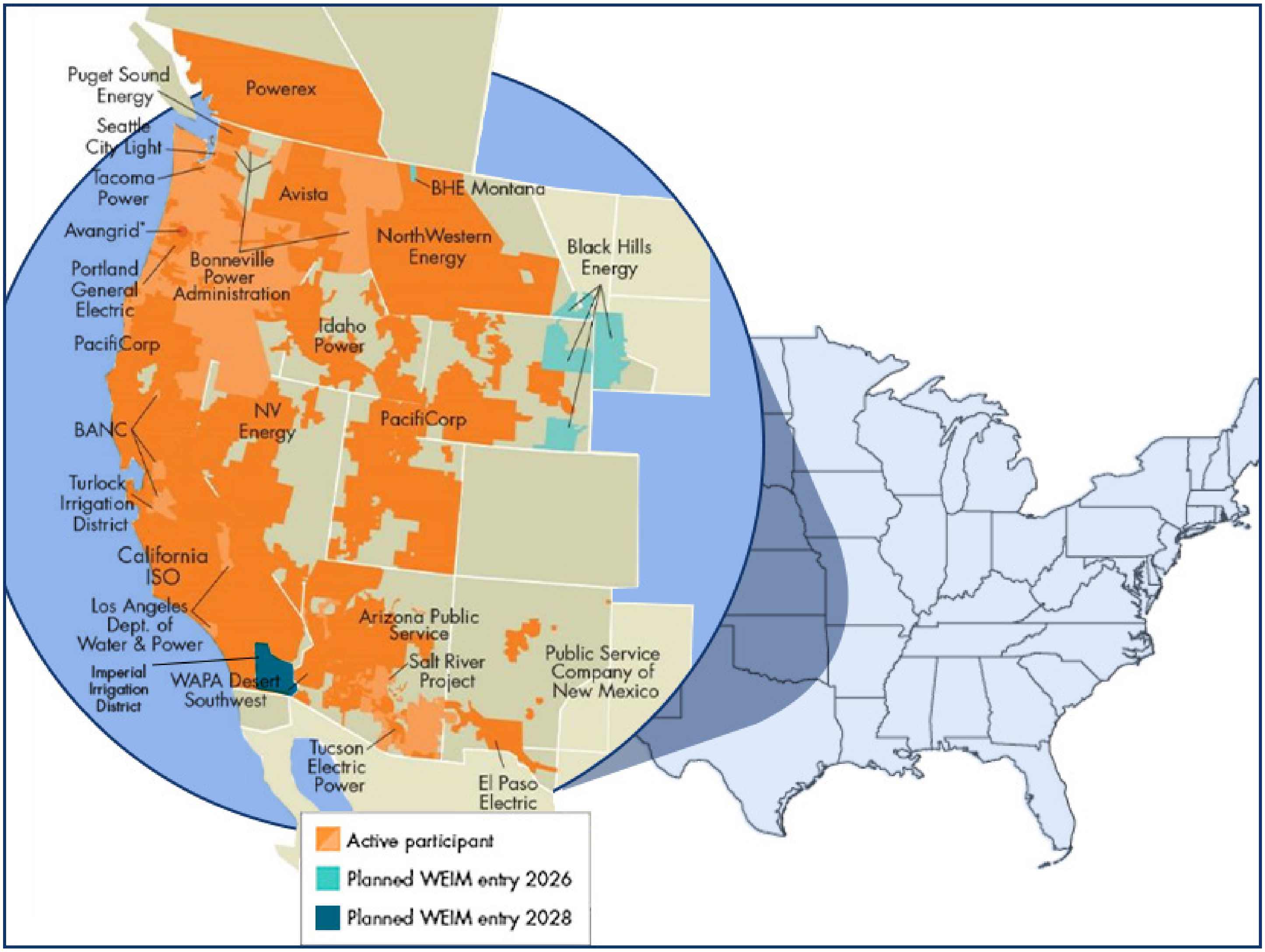
"My biggest concerns are definitely not the seams created by the day-ahead market, but by the breakup of the EIM footprint," said Kelsey Martinez, director of regional markets and transmission strategy for Public Service Company of New Mexico (PNM).

Her comments came during a panel discussion on seams as part of a Western Energy Markets Regional Issues Forum meeting June 17 in Reno, Nev.

Since CAISO launched the WEIM in November 2014, it has grown to include 22 market participants representing about 80% of the electricity demand in the Western Interconnection. As of April 30, WEIM's cumulative gross benefits totaled $6.99 billion, the ISO has estimated.

Why This Matters

The panel discussion at the Western Energy Markets Regional Issues Forum offered additional insight into how complicated market seams issues are going to become as the West splits between CAISO's EDAM and SPP's Markets+.



The anticipated breakup of the real-time Western Energy Imbalance Market as the West forms two day-ahead markets has raised concerns about reliability. | *CAISO*

But participants who choose to join SPP's Markets+ rather than CAISO's Extended Day Ahead Market (EDAM) will leave the WEIM for an SPP day-ahead market.

For PNM, WEIM has helped relieve congestion that comes from "overbuilt" intermittent resources such as solar and wind, Martinez said.

"The EIM footprint has allowed us to integrate most of our renewables," she said. "And we will be faced with a completely new problem when we have the same renewable mix but we don't have the same connectivity through EIM that we used to."

Martinez called for a focus on real-time seams "because those are the ones creating a reliability problem."

Seams Road Map

Panelist Mark Rothleder, CAISO's chief operating officer, said the seams that should be addressed first are those that are needed for the launch of EDAM in 2026.

PacifiCorp is scheduled to go live with EDAM in spring 2026, followed by Portland General Electric (PGE) in the fall. (See *CAISO EDAM Pioneers Share Implementation Details*.)

"Launching EDAM is our main focus and resolving any of those immediate seams issues, especially as they relate to reliability but also market efficiency for EDAM to go live," Rothleder said.

Rothleder said it would be preferable to avoid creating new seams. He proposed "as a concept" learning from the experience with WEIM "to mitigate and not create a real-time seam, especially where one does not exist today."

"The EIM works very efficiently over a wide footprint," he said. "How do you maintain that, even if markets may fragment? We should look for those opportunities and explore them and be open to them."

Pam Sporborg, PGE's director of transmission and markets, said PGE's top focus is for EDAM to go live. She said EDAM is a key strategic goal for PGE that will help address affordability challenges for customers.

"Conversations that distract from the ISO's focus on EDAM go-live or on our focus on EDAM go-live are just non-starters," Sporborg said.

Sporborg proposed the creation of a seams "road map" giving a timeline for when particular seams — such as those between the two markets, or even between EDAM and WEIM — would be addressed. Other panelists liked the idea.

"For me, the value of the road map is it gives us a collaboration point with those who are also looking at Markets+," said Kathy Anderson, transmission and markets senior manager at Idaho Power. "We all are customers of each other. So regardless of what market you're going to be going to, you're likely going to be participating in some way in that other market."

Idaho Power has said it is leaning toward EDAM as its day-ahead market choice.

Rothleder said CAISO hoped to develop a seams road map that it would release to stakeholders for feedback.

Communications Seam

With the competition between EDAM and Markets+ becoming heated at times between proponents of each option, Sporborg called for work on what she called a communications seam. Rather than continuing with the divisive language that's sometimes been used, she said, "We have to be nice to each other."

"As those market footprints are aligning and coming into focus, I think we have an opportunity to step back and reset the way we are communicating with each other and recogniz[e] that we all have common interests at heart," Sporborg said.

"We all want reliability, we all want affordability. We are all making choices that are in the best interest of our customers," she said. ■

Oregon Governor Signs Bill to Create Data Center Rate Class

Law Aims to Prevent Residents from Shouldering Grid Costs for Large Data Facilities

By Robert Mullin

Why This Matters

Oregon's new law could represent the leading edge of state efforts to prevent residential ratepayers from footing the growing costs expected for interconnecting new data centers that consume huge amounts of electricity.

Oregon Gov. Tina Kotek on June 16 signed a bill designed to ensure that operators of large data centers pay for grid upgrades needed to supply them with electricity, avoiding shifting those costs to residential ratepayers as the facilities proliferate across the state.

The Oregon Senate on June 3 voted 18-12 to approve an amended version of *House Bill 3546*, dubbed the POWER Act, followed two days later by the House of Representatives' concurrence and passage 37-17.

The bill directs the Oregon Public Utility Commission to create a new retail rate class for big electricity consumers such as hyperscale data centers and cryptocurrency miners in order to allocate grid upgrade costs "in a manner that is equal or proportional to the costs of serving the class." (See *Oregon House Passes Bill to Shift Energy Costs onto Data Centers*.)

Rep. Pam Marsh (D) sponsored the bill to insulate residential ratepayers from the infrastructure costs associated with serving the burgeoning number of high-consuming data centers in the state, saying the "explosion of huge technology facilities has upended" the traditional process for allocating energy-related costs proportionally among consumers.

The new law, which applies only to the investor-owned utilities overseen by the PUC, stipulates that the new class "must be separate and distinct" from existing rate classes for other commercial or industrial retail electricity consumers and have its own tariff schedule.

The law creates a new class of consumer — "large energy use facility" — to identify electricity customers who are equipped to use 20 MW or more of energy and provide computing services, data processing, web hosting or other related services.

Under the law, the tariff schedule adopted by the PUC must require a large data center to foot the bill for a proportionate share of the grid upgrade costs a utility incurs to serve the facility.

The data center operator would additionally be required to enter a service contract with its utility for a minimum of 10 years and be obligated "to pay a minimum amount or percentage, as determined by the [PUC], based on the retail electricity consumer's projected electricity usage for the electricity services the electric company is contracted to provide for the duration of the contract."

The law does not restrict large data centers from using Oregon's "*direct access*" program, which allows nonresidential consumers to purchase electricity from a PUC-certified electricity service supplier rather than a utility.

'The Whole Freaking Point'

The bill won the support of groups like the NW Energy Coalition, BlueGreen Alliance, Sierra Club and the Oregon Citizens' Utility Board, along with utilities such as PacifiCorp.

However, data center companies voiced their opposition, with the Data Center Coalition in March filing testimony saying that, while it supported the intent of HB 3546, it believed "no customer, industry or class should be singled out for differential or disparate rate treatment unless that approach is backed by verifiable cost-based reasoning."

Ellen Zuckerman, Google's head of energy market development for North and South America, echoed that view during a June 3 panel discussion at the Western Conference of Public Service Commissioners' annual meeting in Portland, Ore.

"If you create a discriminatory rate class for data centers, what signal are you potentially sending to them? Are you telling them then to go off-system and invest in behind-the-meter resources?" Zuckerman said. "You're losing that opportunity to invest their capital in your grid."

Zuckerman asked whether that could create "a system of balkanized planning" and "a paradigm where certain large customers can say 'these resources are only for us'" and not offer them to the broader grid when other generating resources are set to retire.

"These questions are really complicated; they warrant really deep stakeholder conversation," she said.

Speaking on the same panel, CUB Executive Director Bob Jenks said the data center operators are right to call the new rate class "discriminatory." But "that's the whole freaking point of a rate class: discrimination. You're discriminating based on attributes and costs that are being put on the system and allocating them," Jenks said.

"We have a residential rate class because residential customers require a larger distribution network. We have an irrigator rate class because irrigators put unique costs on the system because of their summer usage pattern," he said. "Because of their size, [and] the speed at which they can be built, their growth rate and their inflexibility, data centers have their own attributes that deserve their own rate class." ■


Meta data center in Prineville, Ore. | *Meta*

CAISO Approves New EDAM Congestion Revenue Allocation Design

But Some Uneasy Feelings Linger

By David Krause

CAISO has approved the final proposal in its highest-priority initiative in 2025.

On June 19, the CAISO Board of Governors and Western Energy Markets (WEM) Governing Body at a joint meeting approved a new method for allocating certain congestion revenues in the ISO's Extended Day-Ahead Market (EDAM), set to launch in 2026.

CAISO began the initiative to address a paper by Powerex that said the current EDAM model contains a "design flaw" with potentially $1 billion in unjustifiable charges at stake. (See *Powerex Paper Sparks Dispute over EDAM 'Design Flaw'*.)

Since then, CAISO has issued multiple proposals on the subject and has held stakeholder workshops to resolve potential congestion revenue allocation issues that could arise under EDAM — some of which continue to exist in the final design, certain stakeholders contend. (See *CAISO EDAM Congestion Revenue Proposal Gains Support*.)

"I think it would be an understatement to say that this initiative and proposal seem to be the most intense and engaged issue since the approval of EDAM," Governing Body Chair Robert Kondziolka said at the June 19 meeting. "Although painful at times, the stakeholder process works."

"It's clear that we are in territory that other ISOs haven't navigated, so we are learning as we go," CAISO board Chair Severin Borenstein added.

The proposal is intended to address the fact that congestion revenues, or rents, will occur when a transmission constraint in one EDAM balancing area affects the locational marginal prices in neighboring balancing areas. In these cases, the market operator pays less to suppliers than to market participants.

Under the current EDAM model, congestion revenues would be allocated to the balancing authority area that contains the transmission constraint that is causing congestion on the system. This design is currently in effect in the WEIM and has been approved by FERC.

Under the new design, certain congestion revenues would be allocated to the BA where the energy is scheduled, rather than where the constraint is located. The new design applies in cases of parallel flow — or loop flow — on the system. In these parallel flow situations, congestion revenues will be allocated to an EDAM BA where congestion revenues are collected by using eligible firm Open Access Transmission Tariff transmission rights submitted and cleared as day-ahead balanced self-schedules, CAISO said in a June 12 *memo* on the matter.

The purpose of the new design is to improve congestion cost protections for transmission customers exercising eligible firm transmission rights under the terms of the EDAM entity's OATT, CAISO said in the memo. The design applies only to the day-ahead market, not congestion revenue allocations in the Western Energy Imbalance Market (WEIM).

Most stakeholders support the final design, CAISO staff said at the meeting. However, two primary concerns remain among many stakeholders: one, that the design is 'transitional'; and two, that the design could create economic incentives to self-schedule energy resources.

The Unknowns

For transitional concerns, stakeholders want the ISO to "ensure there is a forum for consideration of a long-term design for congestion revenue allocation as the EDAM footprint grows," CAISO said in its memo. CAISO will therefore hold working groups with stakeholders before EDAM begins in 2026.

After these working groups, CASIO said it will propose a long-term design within the next two years. CAISO will also monitor the performance and impacts of this transitional change using certain metrics that will be shared with stakeholders.

The primary concern of CAISO's Market Surveillance Committee (MSC) is about the new design's potential to create self-scheduling incentives, which potentially reduce the benefits of coordinating unit commitment and dispatch across multiple balancing areas that EDAM is intended to provide, and potentially result in unintended cost shifts, MSC committee members said in a June 16 *memo*.

"We do want to avoid those self-scheduling incentives," consultant Scott Harvey, MSC member, said at the meeting. MSC member, at the meeting. "On the other hand, they might be small … and there is not going to be a lot of self-scheduling in response to these incentives. But we think that is not a given and these are things CAISO needs to look at."

"EDAM is not an off-the-shelf product," Harvey added. "When you're doing something for the first time, you should never assume everything is going to work right."

The ISO's Department of Market Monitor (DMM) agreed the new design is likely to create economic incentives for some inefficient self-scheduling of resources. However, while this will reduce the efficiency benefits from managing congestion over an expanded EDAM footprint relative to the currently approved design, there would still be significant benefits from an expanded market relative to the current pre-EDAM market, Eric Hildebrandt, DMM Executive Director, said in a June 12 *memo*.

The ISO has provided data showing there is reasonable hope that the potential for inefficient self-scheduling would be limited in the PacifiCorp balancing areas, Hildebrandt said. ■

Why This Matters

Addressing congestion revenue allocation has been a critical issue for CAISO before it launches EDAM in 2026.

NWPCC Appoints Former BPA Official as New Executive Director

By Henrik Nilsson

The Northwest Power and Conservation Council has hired Peter Cogswell, the former director of intergovernmental affairs at the Bonneville Power Administration, as its next executive director.

Cogswell will assume the position on July 7, succeeding Bill Edmonds, who stepped down as executive director in April after serving for five years with the council, according to a June 23 news release.

Council Chair Mike Milburn said in a statement that Cogswell "is an experienced leader with an impressive energy policy background who is deeply connected to the region."

"We're confident that Peter will be able to hit the ground running at this critical time as we ramp up our work on the next Columbia River Basin Fish and Wildlife Program and Ninth Northwest Regional Power Plan," Milburn added.

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, with the next plan slated for release in 2026, according to the council's website.

Cogswell will oversee the development of the plan amid an expected sharp increase in energy demand and shifting energy priorities under President Donald Trump. (See *NWPCC's Initial Demand Forecast Sees Sharp Growth for Northwest* and *NWPCC Considers Trump, Data Centers in Regional Power Plan*.)

Why This Matters

Cogswell joins the council as it navigates several challenges in developing its regional power plan, including load growth and shifting energy policies.

The Northwest Power and Conservation Council has appointed Peter Cogswell to the role of executive director. | *NW Council*

For example, the council's initial 20-year forecast found that electric vehicles and data centers could bring annual energy demand in the Pacific Northwest to 31,000 and 44,000 aMW by 2046 — up from an average of approximately 22,000 aMW during the past several years.

The council also is considering updating models used in the 2021 power plan after Trump rescinded several clean energy initiatives implemented under former President Joe Biden.

Cogswell brings decades of experience from the energy industry to the council.

According to his LinkedIn profile, Cogswell joined BPA in October 2007 and served as council liaison and the agency's director of intergovernmental affairs until January 2022. During his time with BPA, Cogswell helped develop two of the council's power plans.

After leaving BPA, Cogswell assumed the role of director of government and external affairs at renewable energy developer Simply Blue.

The release also notes that Cogswell worked at PacifiCorp and as deputy chief of staff and policy adviser to former Oregon Gov. Ted Kulongoski. While in the governor's office, Cogswell "led efforts to adopt several early clean energy policies, including Oregon's first renewable energy standard," according to the release.

"I am very fortunate to have engaged extensively with the council over the course of my career," Cogswell said in a statement. "I am excited about the opportunity to build on that experience by working with members, staff and a broad group of partners, including tribes, states, utilities and advocates, to ensure the council continues its important work in the region."

The NWPCC is an interstate group with representatives from Idaho, Montana, Oregon and Washington, and works with regional partners, including the Bonneville Power Administration, the U.S. Army Corps of Engineers and the Bureau of Reclamation, as well as with FERC, to implement its plans and programs. ■

Inland Wind, Merchant Projects, WestTEC to Guide CAISO Interregional Planning

ISO's Base Case Scenarios Call for Tapping 9.1 GW of Out-of-state Wind Resources

By Elaine Goodman

RENO, Nev. — Out-of-state wind integration, merchant transmission development and the WestTEC planning effort are all factors influencing CAISO's interregional transmission planning.

Neil Millar, CAISO's vice president of infrastructure and operations planning, gave a briefing on the ISO's West-wide transmission activities during the June 18 meeting of the Western Energy Markets Governing Body in Reno, Nev.

As a starting point for interregional transmission planning, CAISO uses its regional transmission planning process, Millar said. The CAISO Board of Governors on May 22 approved the 2024/25 *transmission plan*, which includes 31 projects valued at a total of $4.8 billion. (See *CAISO Approves $4.8B Transmission Plan to Support 76 GW of New Capacity*.)

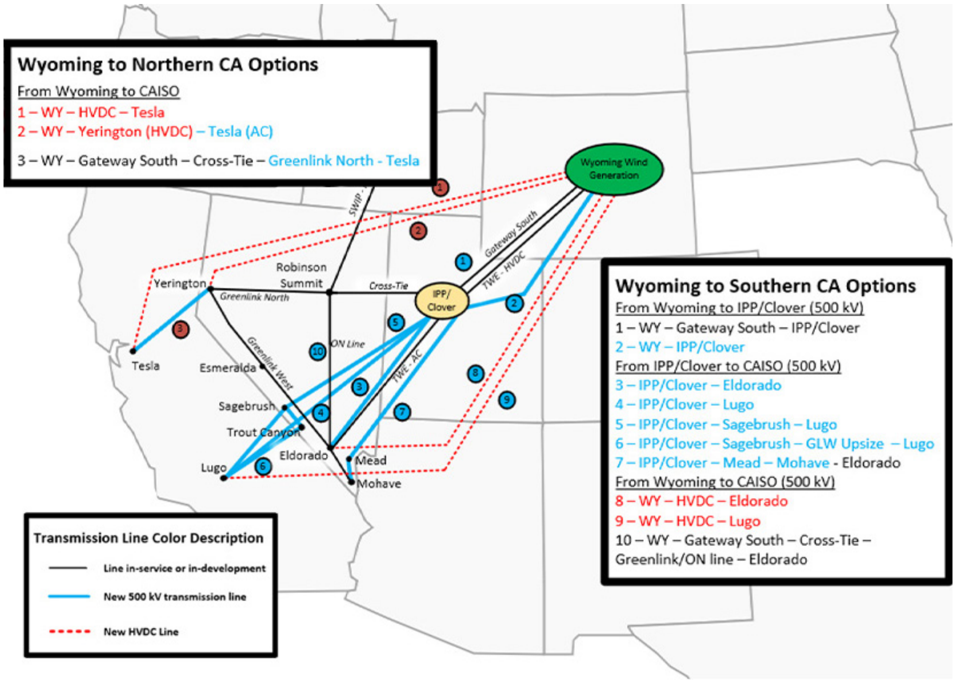
CAISO's previous three transmission plans included $5.8 billion in projects on average, which were largely policy-driven projects to support access to resource basins, Millar said. But projects in the 2024/25 plan are mainly focused on reliability in the face of surging load growth.

Why This Matters

The resource diversity needed to achieve California's ambitious clean energy goals means CAISO will be likely be a key participant in developing new interregional transmission projects in the West.

Millar said last year's transmission plan was based on a load growth of around 1% per year, while the load growth in this year's plan was about 1.6%. CAISO is now looking at a load growth rate of about 2.5% for next year's plan.

"The increased rate of load growth reflected in the most recent load forecast associated with building and other electrification, data center growth and transportation electrification results in significant reliability-driven needs in this year's transmission plan," the 2024/25 plan stated.



CAISO is exploring transmission solutions to integrate wind resources from Wyoming, Idaho and New Mexico. | *CAISO*

Out-of-state Wind

Accessing out-of-state wind continues to be a focus for the ISO. Millar said CAISO's base case scenarios call for seeking more than 5,500 MW of Wyoming and Idaho wind resources and more than 3,600 MW of New Mexico wind.

He said CAISO is working with its neighbors to explore potential coordination on specific projects or to leverage merchant projects that might be moving forward.

And supporting the Western Transmission Expansion Coalition (WestTEC) effort is a priority for CAISO, according to Millar.

The WestTEC effort, jointly facilitated by the Western Power Pool and WECC, will address long-term interregional transmission needs across the Western Interconnection. The goal is to produce transmission portfolios for 10- and 20-year planning horizons.

WestTEC expects to release its initial 10-year horizon report in August, according to a June 12 *presentation* to the group's Regional Engagement Committee. The group projects that the 20-year horizon report and the final 10-year report will be completed by September 2026. (See *WestTEC Tx Study on Track Despite Delays*.)

For Millar, the key advantage of WestTEC is that it will create an "actionable" plan. He said it's one of the first studies based on extensive input from load-serving entities about their resource plans, particularly in its 10-year horizon.

CAISO will use the information to help identify opportunities it will emphasize, either by itself or in collaboration with other entities.

"At this point, I'm not in a position to tell you which projects we're throwing our weight behind, because we are looking to see what falls out from the WestTEC effort first before we move to that next stage," Millar said. ■

Texas Bills Targeting Renewable Resources Come up Short

ERCOT's Important Clean Energy Sector Survives Latest Hurdle

By Tom Kleckner

SAN ANTONIO — Cheers rang out in the Texas Capitol in early June as the lawmakers, lobbyists and public advocates celebrated the end of the biennial legislative session, a 140-day marathon of meetings, hearings and votes.

Fewer celebrated more than perhaps Mark Stover, executive director of the Texas Solar + Storage Association (TSSA). For the second session in a row, clean energy interests dodged the most damaging legislation. Data center developers and other large loads, however, saw several constraints placed on their integration into the ERCOT grid.

Not surprisingly, Stover said he was extremely pleased with the session. The five bills his organization prioritized all made their way to Gov. Greg Abbott's desk. Proposals he said would have "greatly harmed" the clean energy sector, raised energy prices, undermined grid reliability, and weakened economic and business energy strategy died on June 2, the legislature's *sine die*.

The most onerous bill would have required county governments within 25 miles of new renewable projects to hold *hearings before regulators could rule on a permit application* and would have required setbacks from property lines and any habitable structure. A second bill would have stipulated that *50% of all new capacity be sourced from dispatchable generation*, excluding batteries.

Why This Matters

Renewable resources and batteries have been instrumental in helping ERCOT meet demand, fueled by a tsunami of data centers and other large loads, since 2024. Texas' biennial legislative session ended with several bills that would have kneecapped the clean energy sector not making it to the governor's desk.

The Texas Capitol is quiet after the most recent session that largely left renewable resources unscathed. | © *RTO Insider.*

Still a third would have directed existing renewable facilities in the ERCOT region to *back up their energy production* with gas generation or be subject to fines. (See *Growing Clean Energy Sector in Texas May Avoid Damaging Legislation*.)

"These proposals would have distorted the energy market and damaged the all-of-the-above energy strategy that drives success in Texas and is needed more than ever," Stover told *RTO Insider*.

He said lawmakers instead advanced "thoughtful solar power and energy storage policy" and rejected efforts to "unnecessarily punish" grid-scale clean energy or restrict distributed resources.

Aurora Energy Research said in a *report* that restricting renewable energy's expansion would increase the risk of capacity shortfalls and load shedding and increase power prices 14% by 2035. That translates to a 10% increase in customer bills, adding $225 each year to the average Texas household and $6.3 million annually for 100-MW and above industrial consumers. Total system costs would climb by $5.2 billion, the analytics firm said.

"As demand surges, the findings underscore the essential role of renewables and flexible technologies in meeting ERCOT's accelerating electricity needs," Aurora said in the report.

Stover said solar and storage's continued growth, along with the upcoming deployment of the dispatchable reliability reserve service (DRRS) product and real-time co-optimization, will help meet that demand in the near term.

"Solar power and energy storage are the fastest-growing grid technologies in Texas and can be deployed more quickly than any other generation resource," he said. "Solar and storage are best positioned to help Texas meet new load growth while increasing reliability and driving affordability."

ERCOT's generator interconnection queue is indeed dominated by battery storage (174 GW) and solar (158 GW), followed by wind (41 GW) and gas (32 GW). The queue has 2,031 active requests totaling 409 GW of capacity.

Having escaped legislation that could have derailed their progress, renewable resources and storage will be critical in meeting demand over the next few years. Long lead times for steam turbines and the potential negative effects of steel and aluminum tariffs have pushed gas projects into the future. The Texas Energy Fund's low-interest loan program, designed to add 10 GW of gas generation, has had eight projects drop out or be removed in recent months. (See *2 More Projects Fall out of TEF Loan Program*.)

While quipping that he "survived" the session, ERCOT CEO Pablo Vegas said he saw lawmakers keenly focused on trying to bring balance to the grid and its resources, each with their own pros and cons.

"Many of the bills that gave the renewable community concerns, based on the approach of how … they were going to try to bring that balance, were grounded in the right intention," he said in an interview. "'How do we make sure that there is an even playing field for the opportunity and the incentive for reliable long-duration, dispatchable generation?' And I think that's a laudable goal that we still need to continue to focus.

"We just don't want to slow down the growth of energy supply right now in an environment where we're seeing such a significant growth projection and growth forecast ahead of us over the next three, four, five years."

Mark Stover, TSSA | © RTO Insider LLC

ERCOT CEO Pablo Vegas | © RTO Insider LLC

The grid operator is currently tracking about 156 GW of large loads, more than double the 63 GW they were following in December; it defines large loads as those 75 MW or above. Residential load, meanwhile, is growing at 1.2%.

Recent *state legislation* requires ERCOT to include any load in its projections that has not yet signed an interconnection agreement. Recognizing that not all proposed data centers and cryptocurrency mines will show up, staff now apply a discount factor to load projections. They have proposed a 49.8% reduction in data center loads and a 55.4% cut in loads that have been attested to by officers from transmission and distribution providers. (See *ERCOT, PUC Refining Future Load Projections*.)

ERCOT added over 13 GW of capacity last year. However, effective load-carrying capability — generation's ability to serve demand — reduces that capacity to a little bit more than the 7,527 MW of ELCC capacity added in 2001. Much of the additional capacity that year was gas-fired.

"We don't have a shortage of energy on the ERCOT grid. What we really have, for a few hours, are these higher-risk tail-level events [where] we need to make sure we can always keep the lights on," Vegas said. "There's really a lot of energy throughout the year that these data centers can leverage and that are going to be coming online. They're going to bring even more economic support for growth and supply."

Batteries and solar proved instrumental last year in meeting demand. Solar energy provided energy during the afternoon (along with wind, it produced 34.8% of ERCOT's total energy in 2024), with batteries picking up when the sun set. Storage capacity reached 10 GW in 2024 and is forecast to almost triple to 27.5 GW over the next two years.

Vegas called batteries the grid's "Swiss Army knife."

"Batteries can be the load when they're needed. They can be supply when they need to be, and they bring incredible flexibility and agility," he said. "But their duration is limited, and so it's matter of building a portfolio that can leverage all of [batteries'] characteristics and features in a way to bring the most value to the system."

Saying the renewable energy policies were one part of the legislature's storyline, Vegas turned his attention to *Senate Bill 6*. One of the Senate's top priorities, the legislation directs the Public Utility Commission to determine a cost allocation for large loads to ensure they are paying their fair share of infrastructure expenses.

The bill will also require large-load developers to pay a $100,000 fee for the initial screening studies, with an increase for larger capacity requests. That has been met with approval by the crypto-mining community, which says it will address the "phantom loads" in the queue.

Vegas agreed that SB6 will ensure cost allocation is "being done fairly."

"The other side of it was creating that pathway for the large data centers," he said. "Senate Bill 6 really created some clarity and a pathway for that growth to be enabled in a very reliable way. I'm encouraged that the legislature recognized the need for some rules around how to make sure that large energy users could work with the grid and the grid operator in partnership to not only support the economic growth that the data centers are bringing, but the reliability for the rest of the constituents.

"It takes up the questions of cost allocation, and that'll be something that the Public Utility Commission and the stakeholders will work through as well," he added.

As of June 19, Abbott had yet to sign the bill. He has until June 22 to sign or veto legislation. Those he doesn't sign become law. ■

Tenaska Power to Disgorge $28.2M in ERCOT Revenues

Texas PUC Orders $354K Penalty Over Incorrect Ancillary Services

By Tom Kleckner

Tenaska Power Services and the Texas Public Utility Commission have reached a *settlement* in which the company will pay a $353,500 penalty and disgorge $28.24 million in excess revenue made in the ERCOT market in violation of agency rules.

The commission consented to the penalties during its June 20 open meeting (*57437*).

The PUC's Compliance and Enforcement staff recommended the action after investigating Tenaska Power's assignment of ancillary services (AS) from January 2016 through April 2021. Staff said Tenaska, a qualified scheduling entity (QSE) and ERCOT market participant, assigned the services to unqualified load resources.

"Tenaska Power was paid to keep capacity available to provide ancillary services during this period but was incapable of providing the ancillary services assigned to unqualified load resources," staff said.

The investigation found four separate events where Tenaska Power was at fault:

- In 2018, two separate load resources under common ownership were provisionally authorized to provide AS responsibilities for a 90-day period. After a clerical oversight, Tenaska Power continued to assign the responsibility to the unqualified load resources after their provisional authorizations had lapsed. During the 31 days that followed, the resources were inadvertently assigned AS responsibilities for 5,261 intervals.

The Texas PUC's Courtney Hjaltman digs into SWEPCO's system resiliency plan. | *Admin Monitor*

- In January 2018, the company telemetered an incorrect resource status code as the QSE for a third party's generation resource. That led to ERCOT issuing a reliability unit commitment instruction for a unit that was unable to fulfill the request.
- During Winter Storm Uri in February 2021, Tenaska Power received real-time off-line reserve price adder payments for a resource that was on a planned outage when it telemetered incorrect information to ERCOT.
- During the storm, Tenaska Power also telemetered high sustainable limits (HSLs) that incorrectly represented the maximum sustainable energy production capability of resources it represented. The company offered to refund the HSL-related revenues using ERCOT's alternative dispute resolution process. However, at the time, the process was not an available method to return the excess revenues to the market.

Staff said Tenaska Power has since taken corrective measures to prevent similar issues in the future.

Tenaska Power, a subsidiary of Nebraska-based Tenaska, agreed to the administrative fee and the disgorgement.

Tejas Power Eligible for TEF Bonus

The commission sided with staff's recommendation to affirm Tejas Power Generation's eligibility for the Texas Energy Fund's Completion Bonus Grant program. The generator seeks $17.52 million in performance-dependent grants over a 10-year period for a 146-MW project.

Staff said Tejas Power's application was administratively complete and that it completed a review process. The grant is contingent on the resource's timely interconnection to the grid and meeting annual performance measures, including availability for ERCOT dispatch.

Tejas Power is the second recipient of the bonus grant program. The PUC in April entered into a grant agreement with the Lower Colorado River Authority, which is seeking $22.5 million in loans to help build the first of two 188-MW gas-fired units at its Timmerman Power Plant. (See "4 Projects Added to TEF," *Texas PUC Approves 765-kV Transmission Option for Permian Basin*.)

Why This Matters

The settlement agreement wraps up a PUCT investigation that found Tenaska Power Services was paid ancillary services awards for non-performing resources in four different events.

LCRA says the unit is scheduled to reach commercial operations in 2025, ahead of its June 1, 2026, deadline to interconnect.

SWEPCO Resiliency Plan OK'd

The PUC approved Southwestern Electric Power's system reliability plan, but not before reducing the proposed vegetation-management spend by $5.1 million to $83.7 million (*57259*).

Commissioner Courtney Hjaltman *suggested* the reduction to reflect what she said were "excessive estimates" for the project costs. The commissioners agreed to remove 26 projects with benefit/cost ratios of less than 1.0, considered the industry standard.

SWEPCO filed the plan consisting of about $183 million of resiliency projects in November 2024. It reached a unanimous agreement with commission staff, the Office of the Public Utility Counsel, Cities Advocating Reasonable Deregulation, Texas Industrial Energy Consumers and Walmart in March.

The PUC also agreed to intervene in support of MISO's revised expedited resource addition study before FERC that allows a study of a limited set of interconnection requests on an accelerated timeline. FERC rejected the RTO's first attempt in May, saying the grid operator failed to limit the number of projects that could apply (*ER25-2454*). (See *MISO Reapplies for Generator Interconnection Fast Lane with FERC*.) ■

Ontario Integrated Energy Plan Boosts Gas, Nuclear

By Rich Heidorn Jr.

Ontario is putting its chips on nuclear power and natural gas to meet its growing energy demand while directing IESO to incorporate gas distributors and the province's economic development goals in its system planning.

The province's first-ever integrated energy plan, *Energy for Generations*, released June 12, seeks to ensure sufficient capacity for a forecast 75% increase in electric demand over the next 25 years.

Authorized by the 2024 Affordable Energy Act, the plan seeks to integrate planning for electricity, natural gas, hydrogen and emerging fuels along with energy efficiency, demand-side management and distributed energy resources. The five-year planning cycle will provide the "long-term certainty [needed] to make smart investment decisions," according to the plan, which was authored by the province's Ministry of Energy and Mines.

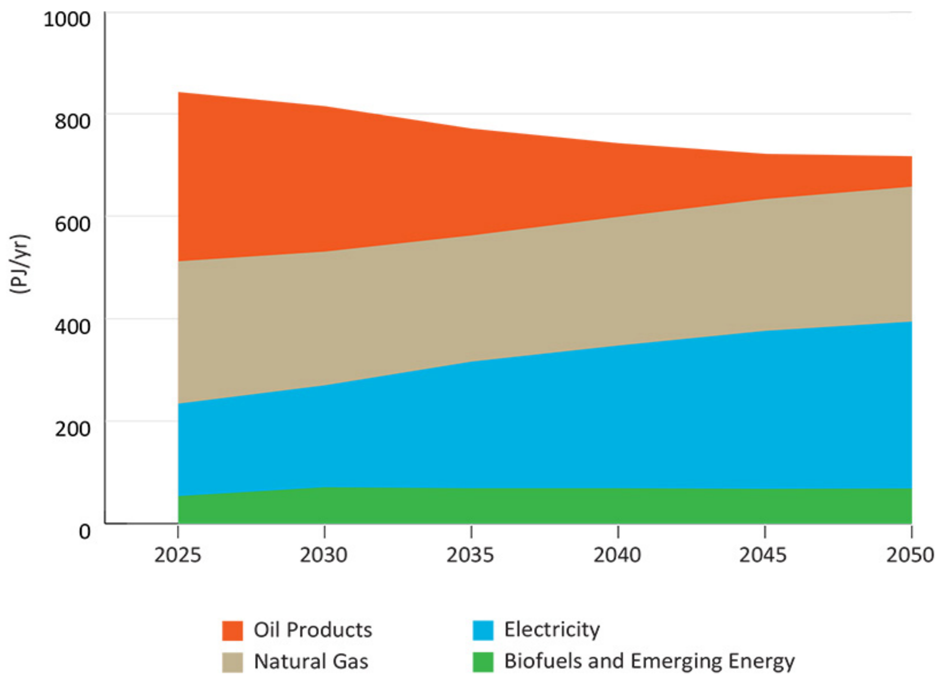
"As the world searches for affordable, secure, reliable and clean energy, Ontario is doing big things," Minister Stephen Lecce wrote in the foreword to the plan. "We are leading the largest expansion of nuclear energy on the continent, building the largest battery storage fleet in the country, adding thousands of kilometers of new electricity transmission and modernizing our grid to meet the needs of tomorrow."

Changing Planning

The ministry declared an end to the "siloed approach" to planning, saying, "For too long, decisions about electricity, natural gas and other fuels have been made separately, without a unified view of how they work together to power the province's economy and communities."

Such coordination will avoid situations where non-pipe alternatives such as electric heat pumps "are advanced without accounting for their impact on local electricity demand and grid capacity," the plan says. (See related story, *Ontario Energy Plan Gives IESO Long 'To Do' List*.)

IESO will be required to identify transmission projects that would be needed under high-growth forecasts to conduct at least annual meetings of Technical Working Groups in each planning region, "in consultation with [local distribution companies], [transmission companies], municipalities and major customers, to ensure more frequent sharing of demand forecasts, system needs and planned infrastructure investments."



While electricity's share of household energy use is expected to grow and oil's to decrease, natural gas's contribution is largely unchanged under Ontario's plan. | *Ontario Ministry of Energy & Mines*

Why This Matters

The province's first-ever integrated energy plan seeks to ensure sufficient capacity for a forecast 75% increase in electric demand over the next 25 years.

Long Bridge for Natural Gas

While the plan endorses an "all of the above" approach to fuel diversity, it places a heavy emphasis on retaining and expanding nuclear power and natural gas.

Natural gas makes up 36% of Ontario's end-use energy consumption and is the home heating fuel for about 75% of residential customers. While climate activists are calling for replacing gas with renewable generation and home electrification, the Ontario government said it supports "the rational expansion of the natural gas network" to serve homeowners in rural and northern areas who do not have access.

Chapter 5 of the plan is the ministry's Natural Gas Policy Statement, which concludes there are few alternatives to gas for Ontario's industrial and agricultural sectors and warns "a premature phaseout of natural gas-fired electricity generation is not feasible and would hurt electricity consumers and the economy."

Although it only provides about 16% of the province's power, natural gas represents 28% of its generation capacity, giving it a critical role in meeting system peaks.

The ministry says gas-fired generation will increase through the 2020s and 2030s because of rising demand and planned nuclear refurbishments. "This will result in a short-term increase in electricity system emissions. However, as new non-emitting supply, particularly new and refurbished nuclear generation comes online, emissions from electricity generation are expected to decline significantly," the plan says.

The province directed the Ontario Energy Board (OEB) to provide a report on expanding its mandate over natural gas and electricity to include alternate energy sources, hydrogen pipelines, carbon dioxide pipelines and district energy systems.

It directed OEB to improve the alignment between gas and electricity policies, citing limits on the grid's ability to serve customers switching from gas to electric heat. It also ordered OEB to develop a new gas connection policy to support faster home building. "OEB will take steps to encourage — and, where appropriate, require — regulated natural gas distributors and LDCs to participate in regional and bulk electricity planning processes," it says.

The province said it supports a new east-west energy corridor to expand access to Western Canadian natural gas and crude oil and reduce reliance on U.S. imports, which account for two-thirds of Ontario's gas consumption.

Big Bets on New Nukes

Ontario is also making big bets on nuclear power, which generates more than half of the province's electricity. In a high electrification scenario, IESO says, the province could need up to 17,800 MW of new nuclear generation in addition to its current 12,000 MW.

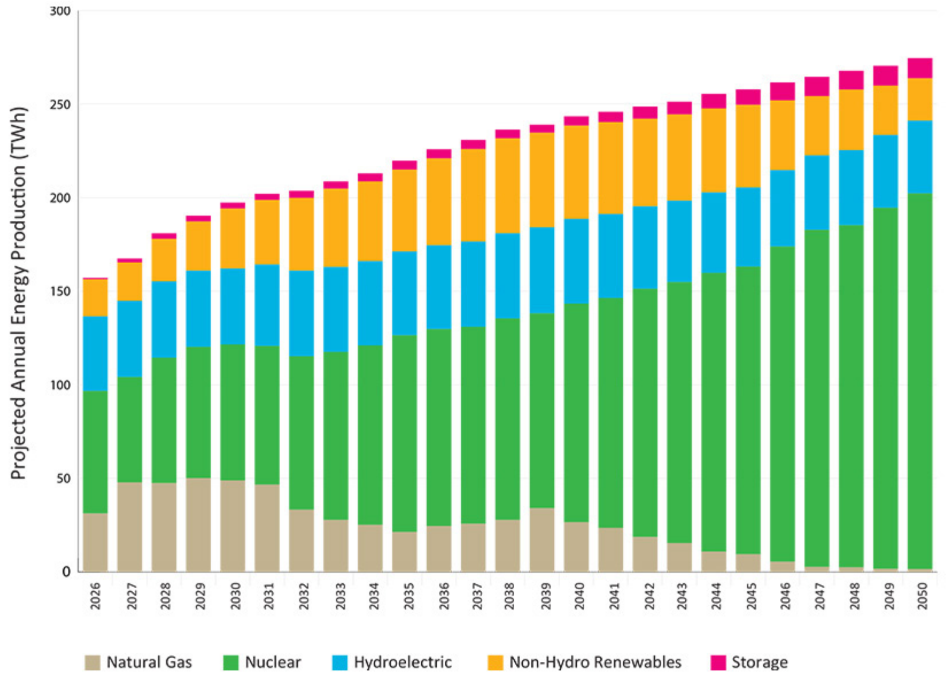
On May 8, Ontario authorized Ontario Power Generation (OPG) to begin construction on the first of four small modular reactors at the Darlington nuclear site. The initial unit, targeted for commercial operation in 2030, would be the first grid-scale SMR in the Group of Seven countries, of which Canada is a member. OPG says building all four SMRs, a total of 1,200 MW, will cost $20.9 billion. The additional SMRs could come online between 2033 and 2035. (See *Ontario Greenlights OPG to Build Small Modular Reactor*.)

The government also is supporting the expansion of the Bruce Nuclear Generating Station, referred to as Bruce C, which could add up to 4,800 MW.

The plan enrolls IESO in a New Nuclear Technology Panel with OPG and Bruce Power "to ensure prospective sites for new nuclear generation are considered in electricity system and transmission planning studies."

Hydropower

The plan calls for expanding and refurbishing the province's hydropower



Ontario sees natural gas's role in electric generation shrinking to almost zero by 2050. | *Ontario Ministry of Energy & Mines*

resources, which provide about 24% of Ontario's electricity, behind only nuclear.

OPG, which is investing $4.7 billion to refurbish and expand its 66 hydroelectric generating stations, has identified up to 4,000 MW of potential new hydropower in northern Ontario. The government is supporting early-stage development for two new sites in the Moose River Basin: Nine Mile Rapids and Grand Rapids.

The plan orders IESO to launch a program to re-contract 26 hydroelectric facilities larger than 10 MW, a total of more than 1,000 MW. The ISO is already working to recontract about 80 small hydroelectric facilities, totaling more than 200 MW.

Other Provisions

The plan also outlines roles for:

- hydrogen, which could constitute 12 to 18% of energy use in the country by 2050 under "supportive policy measures or key input cost reductions."
- energy efficiency, which is earmarked for $10.9 billion in spending over 12 years, "nearly three times [the] historical annual investment."
- pumped storage: The government is supporting predevelopment work for the proposed Ontario Pumped Storage Project, which would provide up to 1,000 MW. OEB is directed to consider changing its rate regulation to support such "long-life" electricity projects.
- storage: The province will add nearly 3,000 MW of energy storage to supplement intermittent renewable generation.
- interconnections: The government is using authority under the 2024 Affordable Energy Act to reduce the capital costs for residential developers and industrial customers connecting to distribution and transmission infrastructure. "These changes will help unlock new developments by reducing investment risk for 'first mover' customers, while ensuring fairness is maintained for ratepayers," the plan says. Draft regulations will be posted for public comment in summer 2025.
- distribution systems: The plan defines grid modernization, directing Ontario's 59 LDCs to make upgrades that allow them to respond more quickly to outages, improve efficiency, and support two-way power flows and real-time system monitoring to accommodate DERs.
- National Energy Corridors for clean energy, transmission and pipelines: "This includes exploring opportunities to build the critical infrastructure needed to move energy and resources east-

Site preparation work is complete for the first of four small modular reactors at Ontario Power Generation's Darlington site. | *Ontario Power Generation*

west across Canada and north to tidewater, including through new transmission lines, pipelines, rail networks and a potential deep-sea port on James Bay."

Transmission

The plan outlines additions to Ontario's 18,600 miles of high-voltage transmission, calling for expanding its north-south "electricity backbone" to reduce constraints preventing generation sites in the north from delivering to loads in the south. In total, IESO has about 932 miles of new transmission lines "under development or planned," according to IESO CEO Leslie Gallinger.

The plan supports the 500-kV Barrie-to-Sudbury single-circuit line, due in service in 2032. "Because of the critical system value to this strengthened corridor, the IESO has also recommended initiating early development work on a second 500-kV line," the plan says.

IESO also has recommended reconductoring the 230-kV Orangeville-to-Barrie line.

The two projects are "critical enablers" for future generation projects such as the proposed Nine Mile Rapids and Grand Rapids hydropower stations, the plan says.

IESO also has identified two major projects in the Greater Toronto Area (GTA): reconductoring the 115-kV Manby-Riverside line, due to be in service in 2026; and a new double-circuit 500-kV line from Bowmanville Switching Station to an existing 500-kV station in the GTA. The line, expected in service in the early 2030s, would connect OPG's SMR units 2, 3 and 4 at Darlington to the grid and send additional electricity to the GTA.

The ministry ordered IESO to recommend by August an option for additional transmission into Downtown Toronto to support growth and electrification. "Once IESO makes a recommendation, the government intends to act quickly to kickstart development, so it can be delivered in the early-to-mid 2030s," the ministry said.

The government has authorized Hydro One to make advance purchases of up to five 750-MVA, 500/230-kV autotransformers that will be deployed in the GTA and southwest and northern Ontario.

Streamlining Regulation

The ministry called for streamlining provincial approval processes for "priority energy projects that are essential to supporting housing, job creation and long-term economic security."

The province is creating a "One Team" initiative to accelerate approvals of "strategically important" energy projects, starting with projects in IESO's Long Term 2 procurement. (See related story, *IESO Purchasing 3,000 MW of Energy and Capacity*.)

In 2022, the government exempted transmission lines wholly funded by commercial, industrial or generator customers from requiring Leave to Construct approval from the OEB. Last year, the government moved all transmission projects into Ontario's Class Environmental Assessment process, which is expected to reduce development timelines for large projects by up to two years.

The government ordered IESO and OEB to review their approval, connection, procurement and regulatory processes and report back on ways they can reduce duplication, shorten timelines and improve efficiency.

"Complex permitting and regulatory processes across multiple ministries and levels of government can create barriers, delays and added costs for projects that are critical to the province's growth and competitiveness," it said. ■

Ontario Energy Plan Gives IESO Long 'To Do' List

By Rich Heidorn Jr.

Ontario's first-ever integrated energy plan includes a long "to do" list for grid operator IESO.

Unlike single-state ISOs in the U.S., which maintain some independence from their state governments and are regulated by FERC, IESO is a wholly government creation, answering to Ontario through the Ministry of Energy and Mines and the Ontario Energy Board (OEB).

The difference is stark. In support of its 152-page energy plan, the ministry on June 12 also issued a prescriptive 12-page directive spelling out in detail how the ISO is to carry out its policy, with sections on planning, district energy systems, distributed energy resources, transmission, low-carbon hydrogen strategy, hydro and nuclear generation, and export opportunities.

It listed 11 "report-backs" e.g., a Dec. 31 deadline for a report on "opportunities to streamline energy related IESO-led procurement processes").

Although the ministry's plan says IESO will continue to lead the development of electricity demand forecasts, it said it must work with the OEB to develop "a formal process to engage natural gas distributors in regional electricity planning activities." (See related story, *Ontario Integrated Energy Plan Boosts Gas, Nukes*.)

"IESO, electricity utilities and natural gas distributors — under the direction of the OEB — will be required to develop coordinated, best-practice scenario modeling to assess future energy needs across fuels as appropriate," the ministry said. "This will improve systemwide consistency on planning assumptions and investment priorities."

The plan directs IESO to ensure its planning supports "long-lead" energy projects such as long-duration storage and new nuclear and hydro projects.

It also requires IESO to expand the mandate of its Strategic Advisory Committee to "reflect the province's broader economic and community priorities" and to increase the panel's membership to include real estate developers, transit agencies and manufacturers. The ministry said technical standards and safety organizations in the province, such as the Electrical Safety Authority and the Technical Standards and Safety Authority, also will participate in SAC meetings. (See *What to Know About IESO*.)

In a *statement* at the plan's release, IESO said it "appreciates the opportunity to be tasked with leading a number of key components that will help meet the province's growing needs."

From left: Energy and Mines Minister Stephen Lecce; IESO CEO Lesley Gallinger; Carla Nell, IESO's EVP for corporate relations, engagement and strategy, and Associate Minister of Energy Sam Oosterhoff at the release of the ministry's integrated energy plan. | IESO

Why This Matters

Unlike single-state ISOs in the U.S., which maintain some independence from their state governments, IESO answers to Ontario through the Ministry of Energy and Mines and the Ontario Energy Board.

In a June 23 *speech* to the Ontario Energy Network, IESO CEO Lesley Gallinger said the grid operator was responding to the plan by "moving faster to build bigger, leveraging the 'no regrets' actions already in motion to make smart investments in new infrastructure."

The ISO also is "implementing a customer-oriented and affordability-minded approach to drive down costs and make it easier for businesses to connect to the grid," she added. "One of the changes I am most excited about is the 'concierge-style' approach we are implementing to ensure customers understand where and how to connect, while streamlining and simplifying our processes so that we can guide customers from start to finish."

Economic Development

Economic development is a recurrent theme in the plan, which calls for making the province "a global clean energy superpower" that exports electricity, nuclear technology, medical isotopes and engineering expertise.

The ministry has proposed legislation requiring IESO and the OEB to "embed economic growth as a priority."

"Integrated planning will be supported by independent, external advice on how best to align energy decisions with broader government priorities — such as housing, economic development and competitiveness," it said.

The government also ordered IESO to create a Major Project Identification Committee for each planning region as "an early warning system … [to] ensure that major housing, industrial and infrastructure projects that could impact electricity demand are identified early and fully accounted for in high-growth demand forecasts."

The committee will include the ministries of energy, economic development and housing, in addition to local and regional economic development agencies and municipalities and Indigenous communities.

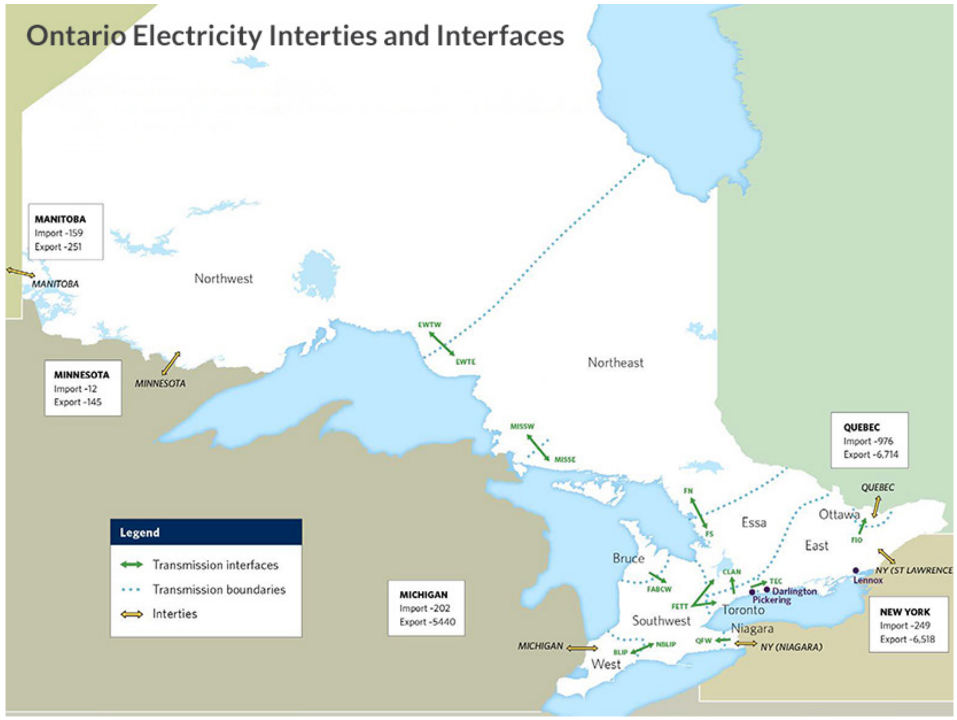
"Municipal governments — who plan for land use, housing and economic development — must be better connected to the province's electricity and fuels planning processes," the plan says.

The government also directs OEB, IESO and other stakeholders to identify improvements to regional and bulk planning processes to "better match the pace of load growth."

Export Potential

Between 2021 and 2023, Ontario exported more than 40 TWh of electricity to the U.S., about 9% of Ontario's total annual generation. In addition to displacing higher-emitting generation in the U.S., the exports have generated $400 million to $700 million annually.

Noting that both NYISO and MISO have warned of growing capacity deficits as fossil fuel plants are shuttered, the plan calls for increasing those exports "once Canadian-American relations normalize." To that end, Ontario and IESO are evaluating transmission upgrades to move power from generators to existing and potential new interties.



Ontario says it hopes to expand its electricity exports to the U.S. "once Canadian-American relations normalize." | *Ontario Ministry of Energy & Mines*

Costs

The plan makes frequent reference to the government's efforts to control electric costs, which it says are at or below the rates in the U.S. Great Lakes states. (See related story *IESO Purchasing 3,000 MW of Energy and Capacity*.)

On April 1, the Canadian government eliminated the previous government's consumer carbon tax on natural gas and gasoline, which is expected to save Ontario households more than $700 annually.

"Ontario's plan to meet growing energy demand while reducing emissions does not and will not include a carbon tax," the plan says. ■

IESO Purchasing 3,000 MW of Energy and Capacity

Ministry Touts Cost Savings

By Rich Heidorn Jr

Continuing Ontario's efforts to replace costly contracts signed under the previous government, IESO announced it has signed contracts with 27 natural gas and wind generators.

In its second medium-term procurement (MT2), the ISO agreed to purchase 2,006 MW of natural gas-fired capacity ranging from $450 to $795/MW-business day beginning in May 2026 and 2029. The weighted average price was $598/MW-business day.

It also agreed to purchase 963 MW from 16 wind generators at prices ranging from $60/MWh to nearly $125/MWh, plus 24 MW of biomass ($204.94/MWh) and 7.82 MW of landfill gas at two sites for $110/MWh and $150/MWh. The weighted average price for all renewables was $79.55/MWh.

IESO said the energy projects were priced 21% below their previous contracts. Although capacity costs were higher than in the ISO's first medium-term procurement (MT1), the Ontario Ministry of Energy and Mines said the costs were 65% below the costs of building new gas-fired generation.

"This success stands in sharp contrast to the fixed, above-market contracts signed by the previous government, which locked Ontario into long-term costs well above market prices," the ministry said in its *integrated energy plan*, released in June. (See related story, *Ontario Integrated Energy Plan Boosts Gas, Nukes*.)

The Progressive Conservative Party has ruled Ontario since ousting the Liberal Party government in 2018. Between 2004 and 2016, the Liberal government signed more than 33,000 contracts, some at up to 10 times market rates and for as long as 20 years, according to the ministry. It criticized what it called "an ideologically driven energy agenda that prioritized over-market, expensive, intermittent generation at a time when it wasn't needed."

Brookfield Renewable's 199-MW Prince Wind I and II projects were among the winners in IESO's second medium-term procurement. | *Brookfield Renewable*

Why This Matters

The procurement continues Ontario's efforts to replace above-market contracts signed by the previous government.

MT2 sought to procure existing energy and capacity resources that are uncontracted or coming to the end of their contracts in the next four years. The *winners* received five-year contracts beginning on May 1 of either 2026, 2027, 2028 or 2029.

"Medium-term [requests for proposals] provide resources greater certainty through longer forward periods and flexible five-year commitments, as compared to the annual capacity auction, while ensuring the IESO is not locked into commitments that are no longer reflective of changing needs," the ISO said.

Eligibility

Biofuel, electric storage and gas facilities were eligible for capacity contracts; biofuel, solar and wind generators were invited to seek energy contracts.

Dispatchable loads and demand response resources were excluded and instead invited to enter IESO's annual capacity auction. The ISO will outline potential changes to the capacity auction, including a revised tie-break methodology, on *June 26*.

The ISO said MT2 gave generation owners not ready to invest in repowering their facilities for the *Long-Term 2 (LT2) Energy* solicitation additional time to prepare proposals for the future LT3 RFP with a contract in place.

1st Procurement

In MT1 in 2022, IESO agreed to acquire 757 MW of nameplate capacity wind and natural gas (309 MW summer UCAP) at prices ranging from $265 to $470/MW-business day (UCAP).

One of the successful bidders in MT1, Atlantic Power's Nipigon Generating Station, also won a contract in MT2, seeing its price rise from $250 to $449.98, an 80% increase.

IESO spokesman Andrew Dow said he could not say why Atlantic Power bid so much higher in MT2 than in MT1. But he said the ISO's "general expectation" is that owners of older generators structure their bids "to make sure that they are recovering enough to help [fund] whatever investments or upgrades are needed to keep their facility running for longer."

The 40-MW *Nipigon plant* has been operating for 33 years.

The ISO said future medium-term RFPs will reflect system needs and "will likely see increased resource eligibility and competition, including the possible inclusion of new-build resources."

Future Procurements

Ontario has already contracted for more than 3,300 MW of new capacity, including battery storage, natural gas and biogas, through the Expedited Long-Term (ELT) and LT1 procurements.

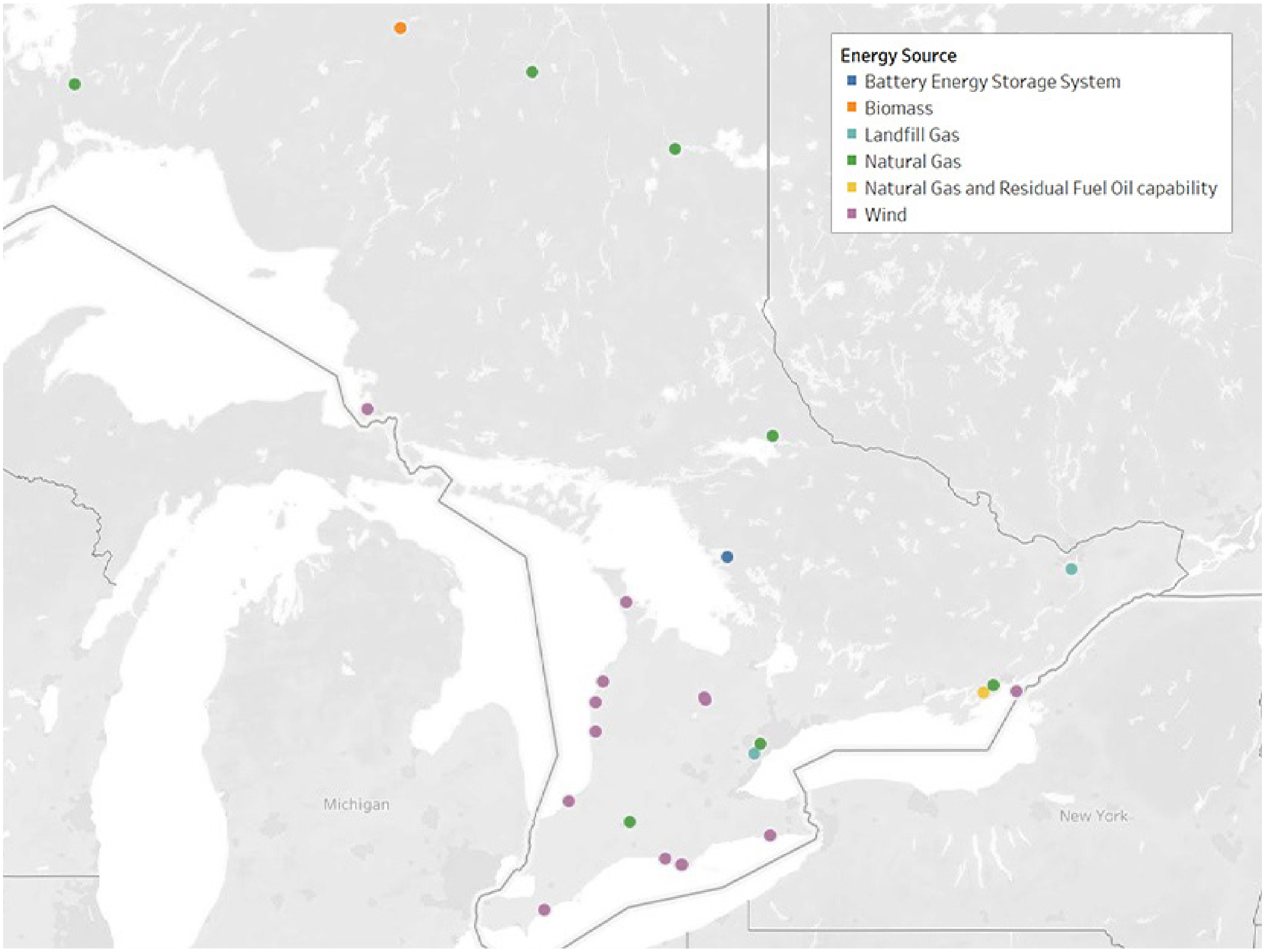
The ministry said LT2 will be the largest electricity procurement in the province's history with a shopping list for up to 14 TWh/year of new energy, equivalent to about 6,000 MW of capacity. The solicitation will be open to energy storage, wind, solar, biomass, biogas, natural gas and energy from waste.

LT2 will also seek 1,600 MW of new capacity resources. Projects will be phased in through four annual intake windows, with in-service dates expected by 2034.

The Ontario Ministry of Agriculture, Food and Agribusiness (OMAFA) and the Ministry of Natural Resources (MNR) will conduct a joint *webinar* on the LT2 procurement on June 25. MNR will discuss requirements for *renewable energy on Crown land*. OMAFA will discuss rules for *energy projects in prime agricultural areas*. The deadline for the first solicitation is Oct. 16.

The province has directed IESO to report back on options for a separate procurement stream for "strategic long-lead projects" such as new hydroelectric generation and long-duration energy storage.

"This stream would help ensure Ontario can continue to plan and diversify its supply mix with assets that support long-term reliability and system flexibility," the ministry said. ■



MT2 RFP results | *IESO*

ISO-NE CEO Gordon van Welie Announces Retirement

By Jon Lamson

ISO-NE CEO Gordon van Welie has announced plans to step down at the end of 2025. He will be replaced by longtime ISO-NE COO Vamsi Chadalavada.

"I have been fortunate to spend 25 wonderful years at the ISO," van Welie said in a statement. "I'm extremely proud of what we've accomplished, from a startup organization to a sophisticated company with world-class people, systems and processes that is well positioned to help the region navigate an increasingly complex energy environment."

Van Welie is by far the longest-serving CEO of any RTO or ISO, having led ISO-NE for most of its history. He has overseen ISO-NE's transition to becoming an RTO, the launch of its capacity market, the shift in the region's generation mix from coal and oil toward natural gas, and multiple overhauls of its wholesale electricity markets.

More recently, ISO-NE has embarked on a series of major changes to its capacity market and is running the first-ever longer-term transmission planning (LTTP) procurement, intended to reduce transmission constraints between northern Maine and southern New England. (See *ISO-NE Discusses Details of New Prompt Capacity Market* and *ISO-NE Releases Longer-term Transmission Planning RFP*.)

In the retirement *announcement*, van Welie said the region's supply and demand outlook should remain "relatively stable through the next several years." The ongoing overhaul of the capacity market and anticipated longer-term changes in the region's resource mix and load profile make this "an appropriate time to step aside and allow new leadership to steer the path forward."

Why This Matters

Van Welie's planned exit comes during a period of significant change at the RTO, and incoming CEO Vamsi Chadalavada will be tasked with juggling challenges related to load growth, the integration of renewables, and increasing conflicts between federal and state policy.

Cheryl LaFleur, chair of the ISO-NE Board of Directors, applauded van Welie on his time with the RTO and said he has "led the ISO through significant transformation, building a strong team of professionals who keep the lights on and run the markets for our region."

"I know Gordon will be missed greatly at the ISO and across the New England region," LaFleur added.

"Gordon van Welie is an institution," said Dan Dolan, president of the New England Power Generators Association. "Gordon has been a thoughtful, innovative and tireless leader for the region. His candor and willingness to engage in difficult, but necessary, conversations is a testament to his commitment to doing what is right for New England."


Vamsi Chadalavada | *ISO-NE*

Chadalavada, who is slated to take over for van Welie at the beginning of 2026, has worked for ISO-NE since 2004 and has served as COO since 2008. As the RTO's second in command, he oversees the operation of the power system and market operations, along with system planning. Like van Welie, Chadalavada worked as a vice president for Siemens Power Transmission and Distribution before joining ISO-NE.

"We are very fortunate to have someone with Vamsi's leadership, experience and qualifications ready to take on the role," LaFleur said. "His appointment demonstrates our strong confidence in his ability to lead the organization through the grid transition ahead."

Reacting to the news, ISO-NE stakeholders commended van Welie on his tenure and retirement and emphasized the major role he has played in ISO-NE's evolution. Industry members also praised the selection of Chadalavada as the next CEO, saying he's well prepared to take the reins.


Gordon van Welie in the ISO-NE control room. | *ISO-NE*

"NEPOOL would like to congratulate Gordon on the announcement of his upcoming retirement," said NEPOOL Chair Sarah Bresolin. "During his tenure, NEPOOL has benefited from his intellect and dedicated service. Gordon leaves the region in a strong position." Bresolin applauded Chadalavada's appointment, which she said leaves the region "in very good hands."

Alex Lawton of Advanced Energy United said Chadalavada "is the right person for the job, and we are confident he will work diligently and collaboratively with stakeholders and the New England states to navigate the evolution of our grid."

Joe LaRusso of the Acadia Center said van Welie's retirement comes at a "pivotal moment" for ISO-NE, with power demand likely to grow after a long period of stability, intermittent renewables set to come online, and increasing conflicts between state and federal energy policy.

"I expect the transition from Gordon to his successor Vamsi Chadalavada to be a smooth one," LaRusso said, adding that Chadalavada "is well aware of all of the challenges facing the ISO and will certainly see current initiatives such as capacity market and reliability reforms, and Longer-Term Transmission Planning and FERC Order 1920 compliance through to completion. The ISO won't deviate much, if at all, from its current path, and Gordon's stamp will inevitably remain imprinted on ISO New England for some years to come." ■

Load Growth Putting Pressure on Capacity Markets in the Northeast

By Jon Lamson

BOSTON — Capacity markets have brought significant cost savings for customers in the Northeast over the past two decades but now face the critical need to evolve amid rapid load growth and a changing resource mix, according to a group of experts.

"We're in a moment that requires a significant amount of evolution," said Liz Delaney, vice president at New Leaf Energy, speaking at the Energy Bar Association's annual Northeast Chapter meeting on June 18.

All three of the Northeastern RTOs have pursued significant capacity market reforms in recent years; ISO-NE and NYISO are in the midst of significant capacity market overhauls — the *Capacity Market Structure Review* project for NYISO and the *Capacity Auction Reform* project for ISO-NE — while FERC approved major resource accreditation changes for PJM in 2024. (See *FERC Approves 1st PJM Proposal out of CIFP*.)

Since the inception of capacity markets, grid operators frequently have made design changes to reduce volatility and improve price formation and resource accreditation, said Marc Montalvo, CEO of Daymark Energy Advisors.

"I think all of these things are evolutionary and are important, and are a sign of a dynamic learning environment, as opposed to a sign of weakness," Montalvo said.

However, with every significant change, "there are dollars at play," Montalvo added. "Politics is just played differently than either engineering or economics, and that's where we find ourselves now."

Why This Matters

ISO-NE and NYISO are undergoing major capacity reform efforts intended to better prepare the regions for a changing resource mix and load profile.

In PJM and MISO, resource retirements and new large loads — including AI data centers — have contributed to major spikes in capacity prices. (See *MISO Summer Capacity Prices Shoot to $666.50 in*

From left: Rosendo Garza, Day Pitney LLP; Marc Montalvo, Daymark Energy Advisors; Walter Graf, PJM; Bruce Anderson, NEPGA; Liz Delaney, New Leaf Energy | © RTO Insider

2025/26 Auction and *PJM Capacity Prices Spike 10-fold in 2025/26 Auction*.)

While New York and New England have not experienced the same level of large loads seeking to come online, both have ambitious transportation and building electrification goals, which, if successful, would drive significant load growth. The region also could see the addition of smaller-scale data centers. (See *Limited Demand for Large-scale Data Centers in New England*.)

Data center growth "really puts pressure on every corner of the industry," said Samuel Newell, principal at the Brattle Group, noting that the recent spike in load growth projections appears to be "much more than our development pipeline, supply chains and transmission planning were ready for."

There's immense uncertainty around data center load growth, and it can be difficult to know if proposed load sources are real or speculative, Newell said.

"There's so many uncertainties with regard to what demand will be, what computational efficiencies will be," Newell said. "I don't think it's realistic to forecast it well."

While rising capacity prices should increase the incentives for new resources, high costs also can cause political blowback for RTOs, a circumstance experienced recently in PJM.

"That's real money in residential, commercial and industrial customers' pockets … and it's turning out to be a real political problem and flashpoint," said Walter Graf, chief economist for PJM.

In New England, the capacity market has successfully signaled whether to build new resources and has helped shield customers from risks associated with generation development, said Bruce Anderson, senior vice president at the New England Power Generators Association (NEPGA).

In recent years, the region has seen "historically low clearing prices, reflective of the system at large," Anderson said. Although ISO-NE anticipates load growth to accelerate over the next 10 years, peak loads in the region have been relatively static over the past decade, in part due to energy efficiency gains and the deployment of rooftop solar.

Anderson said he's "very hopeful" about the capacity reforms underway at ISO-NE and is particularly interested in the capacity accreditation changes, which should allow for increased "substitutability" between different resource types in the market.

He added that ISO-NE's proposal to cut the time between capacity auctions and the capacity commitment period (CCP), and split CCPs into summer and winter periods, should help the region cope with increasing winter reliability risks and enable better-informed investment decisions.

While ISO-NE's CAR project creates short-term market uncertainty, Anderson said he hopes the capacity market that emerges will be able to provide a "period of stability" once finally implemented in the 2028/29 CCP.

"Getting some stability in the market, that really helps in investor confidence and investor decisions," Anderson said.

He also said NEPGA members have discussed the potential to bring back some version of a price lock for new resources, which may help serve as an alternative to strict reliance on state contracts to bring more resources into the market.

In 2020, FERC ordered ISO-NE to eliminate its allowance of a seven-year price lock for new entrants, a move that was supported at the time by NEPGA. (See *FERC Orders End to ISO-NE Capacity Price Locks*.)

Other speakers spoke favorably about a seasonal market construct but expressed some skepticism about ISO-NE's "prompt market" proposal, questioning whether the market will provide enough certainty to attract investment in new resources.

"I'm personally a bit skeptical of the benefits of New England moving from a forward to a prompt structure," Montalvo said.

Delaney of New Leaf emphasized the importance of providing enough transparency to allow participants to model market outcomes multiple years into the future. She added that creating avenues for bilateral contracting is essential to helping new resources come online.

"We need some level of certainty over a significant portion of the revenues to make the math work," Delaney said. ■

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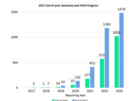

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New England Transmission Owners Add $95M to Asset Condition List

By Jon Lamson

Asset-condition project costs in New England have grown by $95 million since March, according to an update to the project list presented by the region's transmission owners at the ISO-NE Planning Advisory Committee on June 16.

The database includes both in-development and in-service asset-condition projects, which aim to upgrade aging and deteriorating transmission infrastructure.

The change in cost since March, driven by 20 new projects estimated to be about $84 million, is relatively small compared to overall asset-condition spending in the region. It brings the total cost of in-development projects to about $5.9 billion, while the cost of in-service projects totals about $5.5 billion.

While stakeholders broadly agree that many of the upgrades are necessary, ACP spending has become a major issue for states and consumer advocates in recent years because of concerns about rising costs and a lack of transparency and regulatory oversight on the projects. Asset-condition projects are under FERC's jurisdiction, with costs typically recovered through formula rates.

At the urging of the states, ISO-NE has said it is open to taking on an "asset condition reviewer" role to help address the "informational asymmetry" between TOs and the public. The RTO has stressed that this role must not include regulatory responsibilities. (See *ISO-NE Open to Asset Condition Review Role amid Rising Costs*.)

Eversource Energy has already paused stakeholder discussions on a massive, multiphase underground cable replacement project to allow time for ISO-NE review and feedback. The company *wrote in May* that the first phase of the project is estimated to cost between $2 billion and $3 billion. (See *Eversource Outlines Billions in New Boston-area Asset-condition Needs*.)

Also at the PAC on June 16, Eversource introduced a project to replace structures on three lines in New Hampshire near the Maine border. Eversource said it has identified wood pole decay on the lines and proposed to replace all remaining wood structures on the lines at a combined cost of about $52 million.

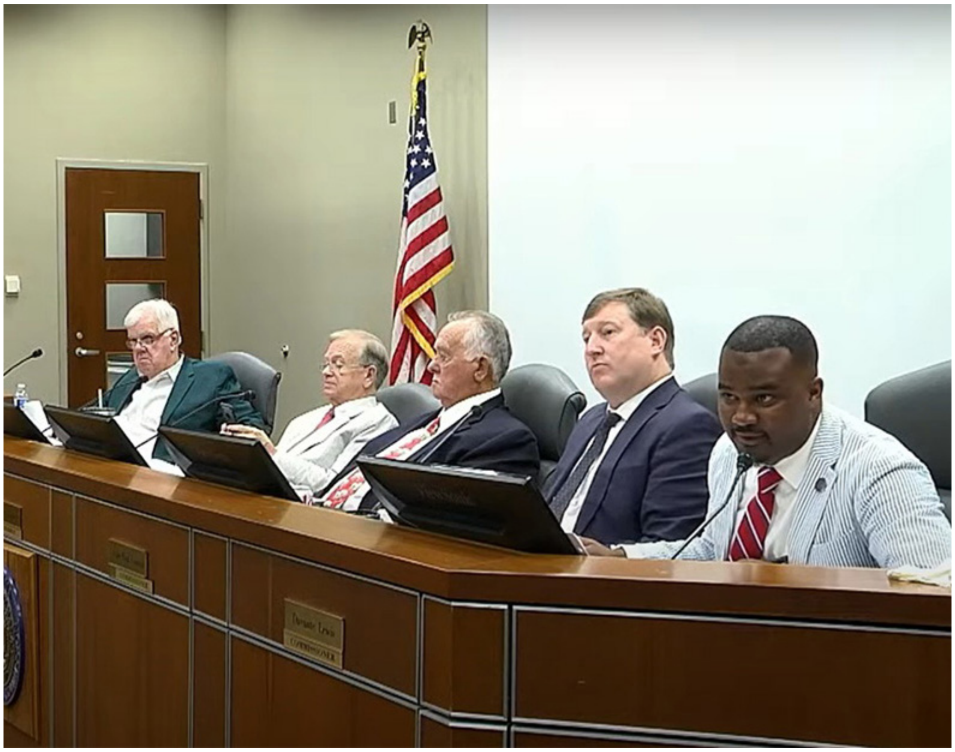
The company also presented a $6 million asset-condition project to replace a pair of breakers on a substation in Springfield, Mass., that are "approaching the end of their useful life and have shown signs of deterioration."

National Grid introduced an $11 million project on a line in Eastern Massachusetts, proposing to replace damaged shield wire, attachment hardware and insulation, and repair the foundations of four river-crossing towers. ■

A cracked wooden pole on an Eversource transmission line in New Hampshire | *Eversource Energy*

MISO Debates What-ifs, Vows Improvements in Front of La. PSC After Load Shed

By Amanda Durish Cook


The Louisiana Public Service Commission at its June 18 meeting | *La. PSC*

MISO leadership again promised to step up the RTO's advance communication of tight system conditions following its four-hour load-shed directive for about 600 MW in Greater New Orleans on May 25.

MISO dispatched Senior Vice President Todd Hillman and MISO Executive Director of Market Operations JT Smith to the Louisiana Public Service Commission's June 18 meeting to elucidate steps leading up to the blackouts and face censure from commissioners.

Hillman said MISO is thinking through how it can better communicate the risk it expects before "these types of rare and unfortunate events." He said MISO is accountable as the reliability coordinator of the wholesale electric grid and that staff worked diligently on that Sunday to combat unavailable generation, transmission congestion and a tornado-damaged, unreachable Nelson-Richard 500-kV line. (See *MISO Says Public Communication Needs Work After NOLA Load Shed*.)

Hillman told commissioners that because the emergency ultimately can be traced to a transmission emergency instead of a capacity emergency, MISO did not sequence through its typical alerts and warnings before resorting to load shed.

MISO's capacity advisories and maximum generation alerts and warnings are reserved for when MISO could be short on capacity, not transmission availability. Hillman said MISO doesn't have warning protocols for transmission emergencies and is working on implementing some.

"We don't have a lot of those. We're not quite used to those," he said of transmission emergencies.

Entergy CEO Phillip May said Entergy is similarly investigating how to improve the "timeliness of communication of load-shed risk."

Commissioner Foster Campbell asked Hillman if MISO thought it owed people compensation for damages, lost revenue and adverse health outcomes during the blackouts. He said it's "hard to swallow" that customers are obligated to not miss bills, but MISO could drop the ball without consequence.

Like he did before the New Orleans City Council, Hillman explained that MISO does not interact with retail customers and only has operational control over Entergy and Cleco's transmission, not generation. He said MISO is a nonprofit that doesn't have a mechanism to reimburse ratepayers, and its wholesale customers are Entergy and Cleco. (See *NOLA City Council Puts Entergy, MISO in Hot Seat over Outages* and *MISO: New Orleans Area Outages Owed to Scant Gen, Congestion, Heat*.)

Campbell said Entergy seemed to be pointing the finger at MISO for providing roughly eight minutes of notification before the utility was forced to take load offline. Once MISO identified the risk of exceeding an interconnection reliability operating limit (IROL) on Entergy's system on May 25, the RTO had a total of 30 minutes to offload demand and clear conditions per NERC requirements.

"That's the nature of the conditions of this IROL," Hillman said.

May confirmed that Entergy had less than 10 minutes to comply and dial down load.

Smith said MISO spent some of the half-hour trying to find alternatives to the last resort of blackouts. He added that MISO is trying to figure out if it met NERC's 30-minute time limit and told commissioners MISO should have been "commu-

Why This Matters

Once again, MISO leadership said the late May blackouts in New Orleans are likely a catalyst for the RTO creating a transmission emergency warning system in addition to its existing capacity emergency warnings. Louisiana state commissioners rebuked MISO for providing notice only mere minutes before directing load shed.

nicating much earlier about this risk."

In addition to 2.65 GW of planned outages across four generating units near the southeastern Louisiana load pocket, MISO experienced eight unplanned generation outages on May 25 totaling 3.86 GW. Generation derates accounted for another lost 1.1 GW on top of that.

"That's just a very large number to have out in a load pocket," Hillman said.

Commissioner Davante Lewis asked if MISO would name the generators. He said that although he knew of Entergy's two offline nuclear units, no one has identified the other generators.

Hillman said MISO would provide that information in data response requests and only when a utility has allowed MISO to release the information. MISO as a rule doesn't identify units that are on outage.

However, Commissioner Eric Skrmetta said Entergy told him it has a waiver letter on file with MISO that allows the RTO to disclose utility data when asked by the commission. He said he viewed it as a "serious infraction" that MISO seemed not to follow the waiver letter and noted that commissioners must answer questions from the public and the press while MISO does not. He added that the PSC will seek data requests.

Skrmetta said he thought MISO could have "staved off" some of the load shed by turning to some of Entergy's more than 400 MW of interruptible customers. He said some generating units that were on unplanned outage had been offline for days at that point, so they wouldn't have shown up in the day-ahead market that morning either.

MISO's Todd Hillman addresses the Louisiana Public Service Commission at its June 18 meeting. | *La. PSC*

Skrmetta said the outage seemed carried out "in more of a panic" than in a "planned, methodical … activation." He said in pre-RTO days, it seemed that companies took more pains to avoid blackouts, and the PSC could issue fines against shareholders and order rate credits for the public. He said in this case, the PSC is left with no recourse save for maybe a class-action lawsuit against MISO because it left Entergy and Cleco no choice but to "start flipping switches" or risk widespread system damage.

"I think we've got real problems with this," Skrmetta said. "It's unacceptable, and I hope people find a way to, you know, effectively get their pound of flesh out of you. We're not going to be able to do it, but we're going to have to find a way to make it more reliable in the future."

Skrmetta said he did not need MISO leadership to respond to his criticisms.

Earlier, Hillman said he understood the load-shed event was "frustrating, disruptive and deeply concerning."

Lewis asked if MISO had ever before experienced so many outages in a single local resource zone.

Smith said outside of significant storm damage, he couldn't recall ever having "such a consolidated area of outages like that."

Lewis noted that some unplanned outages already were in play the week prior and asked what conversations MISO had around contingencies ahead of time.

Hillman said communications were flowing between operators, with reconfiguration plans, studies and analyses performed throughout the day.

Smith said May 24 started out remarkably similar to May 25, but storms in the afternoon cooled the air and dampened demand. He said operator logs from May 24 noted that MISO was coming close to localized load shed, though they managed conditions with reconfiguration and dispatching generation down to avoid infrastructure damage.

Commissioner Jean-Paul P. Coussan asked if the load-shed judgment call was the result of automated processes or AI use.

Hillman said while a computer system runs system simulations, it's backed up by MISO's experienced human operators. He said the decisions that day were not dominated by technology, and control room operators tested conclusions and made phone calls to members in a plea for emergency-range output before making the order.

Smith said that on May 25, about 160 MW of Entergy's approximately 400 MW of load-modifying resources were available with about four-hour lead times. Had MISO called them up in advance, they may have improved conditions, he said.

However, Smith said MISO's forecasts at the time were "generally good" and its forward-view models did not reflect "the dire conditions that were eventually shown." He said the IROL was unforeseen, and MISO is investigating the accuracy of its modeling. Hillman said in addition to modeling improvements, MISO is considering introducing drills so it can lay out what members can expect in a transmission emergency.

Lewis said the event clearly shows that Louisiana needs more transmission capacity in and around the Downstream of Gypsy load pocket. That load pocket predates Entergy's inclusion into MISO.

May said Entergy is pursuing multiple "significant" transmission projects that could help inject more power into the Amite South load pocket, which encompasses most of southeastern Louisiana and includes the Downstream of Gypsy load pocket. Entergy representatives said a new 41-mile, 230-kV Adams Creek-to-Robert line approved under MISO's 2023 Transmission Expansion Plan and expected to be in service at the end of 2027 should help the area by adding 100 MW of import capability.

Asked by Lewis about Entergy's receptiveness to long-range transmission planning from MISO, Entergy Associate General Counsel Matthew Brown said he didn't believe long-term transmission is best suited to resolve load pockets in Louisiana. Brown said more targeted transmission that can be built quickly is an ideal solution, not big-picture, long-range projects that can take a decade to build and can assign costs to customers in states that don't stand to benefit.

Lewis said he worried that without some intensive transmission planning, Louisiana could be in for more problems. ■

MISO Declares Max Gen Emergency in Heat Wave

June 23 Peak Load Approached RTO's High-end Forecast for the Month

By Amanda Durish Cook

MISO Midwest entered emergency status June 23 during the RTO's first serious heat wave of the summer.

MISO *declared* a maximum generation event for 4-10 p.m. ET, when it estimated that all available resources would be in use. The step one declaration allows the RTO to commit emergency resources and curtail export schedules.

The grid operator said a combination of wide-ranging heat, higher-than-forecast load, forced outages and restricted transfer capabilities necessitated escalating its earlier emergency warning to an emergency event.

Based on forecasts made in the morning, MISO foresaw the most pressing problem occurring around 7 p.m. ET, when its approximately 121 GW of available capacity would come a few megawatts shy of its load forecast. By afternoon, however, it no longer predicted a deficit.

MISO additionally issued a maximum generation warning for June 24.

The RTO originally forecasted 122.8 GW of demand for June 23. At 1 p.m. ET, its members were serving almost 114 GW of load at a marginal cost of $324.77/MWh. Indianapolis, Detroit and St. Louis were all forecast to hit 95 degrees Fahrenheit or higher June 23. At midday, solar generation was contributing about 12.5 GW and wind 13 GW.

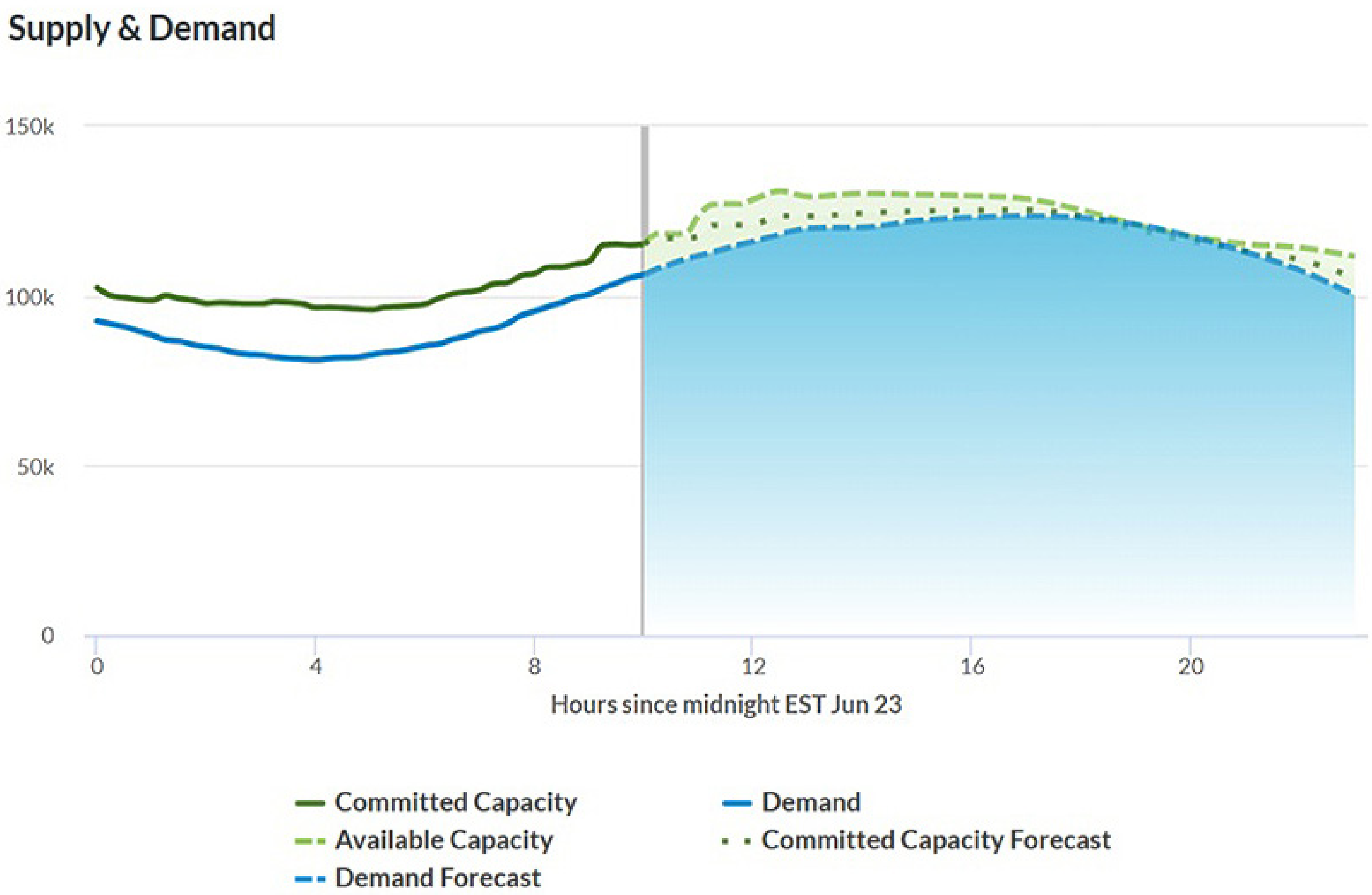
By 6 p.m., MISO was meeting about 119 GW of demand with the help of 5.2 GW of imports priced at around $139/MWh. By then, it had recalibrated its peak demand forecast down to about 120.7 GW.

MISO has been preparing for a sweltering summer. In an outlook issued in May, it estimated it could see a June peak load of nearly 122 GW in a high-demand scenario but expected the peak would more likely top out at 115 GW. The RTO's July forecast called for a 122.6 GW peak under normal conditions and a high-demand scenario of 129.3 GW. (See *MISO Braces for Hot Summer, Potential 130-GW Peak*.)

MISO also *initiated* a capacity advisory for the South region June 21 due to forced generation outages. ■

Why This Matters

The early-summer emergency could portend a challenging season for MISO despite preparations for sweltering conditions.



MISO supply and demand forecast as of midday June 23 | *MISO*

NERC Responds to MISO IMM's LTRA Criticism

'Mismatched Data' Blamed for High-risk Assessment

By Holden Mann

In a *statement*, NERC blamed "mismatched data" submitted by MISO for a calculation in its *2024 Long-Term Reliability Assessment* that resulted in the ERO warning that the region could face energy shortfalls in 2025, while acknowledging its own responsibility for the mistake.

MISO's Independent Market Monitor David Patton called out the ERO for what he called a "completely inaccurate" perception at a June 10 Markets Committee meeting of the ISO's Board of Directors in Minneapolis. (See *MISO IMM Blasts NERC Long-term Assessment, Says RTO in Good RA Spot*.)

MISO was the only area of the continent labeled as "high risk" in the LTRA, published Dec. 17, 2024. The designation means that energy shortfalls are likely to occur under normal peak summer or winter conditions in the next five years. NERC said at the time that resource additions had not kept pace with retirements of coal-fired generation since 2023, causing "a sharp [projected] decline in anticipated resources" beginning in summer 2025. (See *NERC Warns Challenges 'Mounting' in Coming Decade*.)

However, Patton asserted that NERC had incorrectly used MISO's unforced capacity values instead of its installed capacity, then compared the resulting numbers to an installed capacity requirement. This error, which Patton called "an apples and oranges assessment," reduced the region's capacity by more than 10 GW in the LTRA.

Why This Matters

MISO IMM David Patton said NERC's miscalculation of the RTO's risk level in the LTRA has had nationwide consequences, including the extension of a Michigan coal plant that was scheduled to retire.

MISO IMM David Patton | © *RTO Insider*

NERC's statement said the ERO conducted an "in-depth review" and found MISO's submitted data "overstated the near-term energy shortfall risk." When the analysis was rerun with corrected data, NERC found MISO should be reclassified as "elevated risk" for the 2025-to-2027 time frame, meaning resources are sufficient for normal conditions but shortfalls could occur under extreme weather conditions.

"While this data mismatch went unnoticed by MISO and the Midwest Reliability Organization (MRO) that initially collects and vets the data, NERC is ultimately responsible for ensuring the accuracy of its independent reliability assessments," NERC said. "Going forward, NERC, MRO and MISO are all committed to improving the data validation process to ensure accuracy."

NERC said it regrets the discrepancy and plans to post a corrected version of the LTRA "soon," but it did not specify a time frame.

MISO's risk level still could rise to high by 2028, NERC said, "depending on new resource additions [and] retirements." The new data did not require MISO's standing in the *2025 Summer Reliability Assessment* to be changed, according to the ERO, because that report uses different data. The SRA found that MISO was at elevated risk of shortfalls, along with MRO-SaskPower, MRO-SPP, ERCOT, NPCC and WECC-Mexico in Baja California. (See *NERC Warns Summer Shortfalls Possible in Multiple Regions*.)

At the MISO board meeting, Patton said the misleading LTRA already has influenced national policy, as shown by the Department of Energy's directive to keep a 1.4-GW coal plant in Michigan operating over the summer. (See *Consumers Energy Seeking Compensation for Keeping Campbell Open*.) He warned the confusion could "lead to FERC ordering market changes that are unnecessary." ■

MISO IMM Contends he Should Have Role in Tx Planning Oversight

By Amanda Durish Cook

Why This Matters

FERC will decide soon whether MISO's Independent Market Monitor should be able to continue to scrutinize the RTO's transmission planning. Multiple intervenors in the docket have echoed the IMM's view that RTO markets and transmission planning are intrinsically linked.

The MISO Independent Market Monitor insisted to FERC that MISO's own rules allow him to assess transmission. Market monitors of other grid operators backed him up.

MISO's transmission owners, on the other hand, remain steadfast with MISO that it's inappropriate for the IMM to critique transmission planning and expect compensation (EL25-80).

The varied opinions sent to FERC were in response to MISO's May petition for a declaratory order on whether it's proper for the IMM to analyze the value of proposed transmission portfolios in addition to markets. (See *MISO Intent on Answers as to IMM Role in Tx Planning* and *MISO IMM to State Regulators: Good Intentions Behind LRTP Criticism*.)

IMM David Patton argued the RTO's tariff "unambiguously authorizes" him to monitor market impacts of MISO's transmission planning.

Patton cited a tariff section on monitoring duties that listed evaluation of "competitive or other market impacts of tariffs and agreements, or other rules, standards or procedures, or any other transmission provider or market participant actions governing or affecting any of the markets and services." He said the section is intentionally "broadly worded."

Patton requested that FERC deny MISO's petition and find that the IMM is allowed to monitor transmission planning free from MISO's impediment. He included an ask for fast-track status because he said he's currently prevented from "monitoring transmission planning decisions that will have consequential market impacts."

"We also note that almost all the MISO states support the IMM's role in monitoring of MISO's transmission planning and have raised concerns about MISO's attempts to suppress the views of the IMM," Patton wrote in a June 13 response.

MISO argues the IMM's perspective on its transmission studies is "supported by [neither] the commission's policy statement on Market Monitoring Units nor Order No. 719." MISO said beginning in 2023, it noticed the IMM was "expanding the scope of its activities by initiating unsolicited monitoring, evaluations and analyses" of MISO's long-range transmission planning (LRTP) while seeking reimbursement.

According to MISO, the IMM has billed it for about 600 hours of "unsolicited" monitoring of LRTP between 2023 and 2024, totaling about $300,000.

Patton was a vocal opponent of MISO's second long-range transmission plan (LRTP) portfolio throughout 2024, repeatedly telling planners they were overstating the benefits of the collection of mostly 765-kV lines and deeming the 20-year future assumptions that transmission needs were established upon unrealistic. Patton argued for a downsized portfolio. (See *MISO IMM Makes Closing Arguments Against $21.8B Long-range Tx Plan* and *$21.8B Long-range Tx Plan Goes to Membership Vote; MISO Resolute, IMM Protesting*.)

Patton said the tariff's Module D, which contains a MISO-IMM monitoring plan, "expressly empowers the IMM to monitor activities that the IMM 'deems relevant'" and include reviewing agreements, rules, standards and procedures, in addition to other activities that have market impacts or can affect services. He said it's "apparent that transmission planning decisions substantially affect the MISO's market and services."

Patton said FERC and the courts have decided "repeatedly" that transmission planning affects grid operators' markets.

MISO says that view is a slippery slope. Having the IMM review so many aspects "could disrupt the efficient operations at MISO and introduce unnecessary costs, which all, in turn, could impact reliability and the benefits received by MISO members."

Patton said there's no evidence to support MISO's claim.

"On the contrary, in nearly every case where the IMM has raised concerns regarding MISO's actions, MISO has worked collaboratively to make improvements that have yielded substantial efficiency benefits and other savings," Patton said.

'Unsolicited'

Patton objected to MISO's description of the planning advice as "unsolicited." He said MISO does not "solicit" market monitoring "particularly when MISO is the focus of the monitoring."

"It is likely that all monitored entities, whether market participants or MISO itself, would view investigations by the IMM to be 'unsolicited' since no target of our monitoring and investigation would ever voluntarily solicit such activity by the IMM," Patton reasoned.

Patton pointed out that the MISO board of directors had requested that he discuss his divergent view of the MISO transmission planning futures and benefits estimates with RTO staff. He also said MISO reserved time for his presentations at LRTP workshops and stakeholder meetings.

Patton also said he was offended that MISO seemed to suggest his reviews of LRTP assumptions were motivated by money.

"MISO seems to be implying that our monitoring of transmission planning is motivated by a desire for increased compensation, which is offensive and baseless. Like all market monitoring work, we bill our work on an hourly basis. The only reason the hours related to transmission planning monitoring have increased in the past two years above the historical level of effort in the prior 20 is due to the profound concerns that we have uncovered with MISO's most recent determinations," Patton said. He said the $300,000 billed over 2023 and 2024 represents less than 2% of the MISO IMM budget and didn't push MISO's IMM spending over budget.

Patton said market monitors in other regions like NYISO and PJM monitor transmission planning. He said that "further demonstrates that our actions with respect to MISO's LRTP were in no way abnormal or out of step with the commission's requirements."

PJM IMM Supports MISO IMM

PJM's Independent Market Monitor said MISO appeared to be trying to "curtail" its IMM. Monitoring related to transmission planning is "within the proper scope of the market monitoring function." The PJM IMM said MISO's petition "represents an unreasonable intrusion" into the IMM's independence. It sided with Patton that MISO's tariff "clearly" authorizes the Monitor to keep an eye on transmission planning.

MISO IMM David Patton | © *RTO Insider*

The Internal Market Monitor of ISO-NE said scrutinizing how effective markets are at signaling needed investment in generation and transmission is "indisputably within the bailiwick of an IMM." The ISO-NE IMM argued that examining transmission planning for its impacts on the market is "two sides of the same coin."

"The performance and competitiveness of wholesale markets are inextricably linked to the operation, access arrangements and long-term planning of the transmission system," the ISO-NE Monitor wrote.

The New Jersey Division of Rate Counsel and Maryland Office of People's Counsel even registered support for the MISO IMM in a joint filing. They said the "activities performed are an important part of an IMM's work in ensuring market fairness."

The Office of the Illinois Attorney General said it would be a "great disservice to ratepayers" if FERC were to agree with MISO and limit the IMM's authority.

MISO's transmission owners, however, said "unsolicited monitoring and evaluation" of transmission planning is "beyond the bounds" of the IMM's tariff-designated responsibilities.

"While Potomac may undertake such activities of its own volition, it should not do so with the expectation of compensation from MISO, its members and their ratepayers," the transmission owners said.

Americans for a Clean Energy Grid expressed a similar sentiment: "Though the IMM serves a vital role in the operation of MISO's markets, the tariff does not extend this role to transmission planning and monitoring activities." The group agreed that MISO is under no obligation to reimburse the IMM for transmission evaluation. ■

MISO's Queue Fast Lane, Take 2, Nets Déjà vu Arguments

By Amanda Durish Cook

MISO's repackaged proposal to establish a temporary fast track in its interconnection queue resulted in a familiar division among MISO stakeholders, with vertically integrated utilities campaigning for the proposal and clean energy organizations protesting.

MISO in early June refiled the fast-track proposal, this time with a 68-project limit that includes special reservations for retail choice states and independent power producers. The grid operator managed to refile nearly 1,000 pages of tariff changes, explanation and testimony within three weeks (*ER25-2454*). (See *MISO Reapplies for Generator Interconnection Fast Lane with FERC*.)

MISO committed to processing 10 fast-track applications per quarter for five quarters. Additionally, it added placeholders for 10 projects from independent power producers who have power purchase agreements with non-utility entities and an additional eight projects that can be submitted only by retail states for resource adequacy deficiencies. MISO would sunset the expedited process no later than mid-2027, or until the project limit is reached.

Clean energy groups aren't fans of the revised proposal.

A joint filing from Sierra Club, Sustainable FERC Project and Union of Concerned Scientists, among others, said the proposal still confers "preferential access to thermal resources at the expense of renewable resources." They said MISO again failed to establish why the fast track was mission-critical for resource adequacy.

In a press release, Sierra Club said MISO submitted "a plan that will take place over many years and fails to justify the cap size it chose." The nonprofit said MISO finalized the new plan "after a single stakeholder meeting that only allowed one round of Q&A and an informal exchange of ideas on how to improve the first discriminatory plan." It also noted

Wisconsin Public Service Corp.'s Weston RICE units. | *WEC Energy Group* that the proposal's 10-day comment period included two weekends, "giving all stakeholders only six working days to evaluate" and form responses to the new proposal.

Advanced Energy United, the American Clean Power Association, the Solar Energy Industries Association, the Southern Renewable Energy Association and Clean Grid Alliance said MISO's filing "retains many of the shortcomings" of the first while introducing new legal concerns. It said MISO should clarify that its guarantee of spots for independent power producers with non-load serving entity off-takers should not preclude them from competing for the 50 original spots.

"Accepting MISO's unjust, unreasonable and unduly discriminatory and preferential proposal would undermine open access principles in the MISO region, derail the region's existing generation queue, cast a pall of litigation risk over all stakeholders and ultimately jeopardize the long-term reliability and resource adequacy of the region," the quintet wrote in a joint protest.

The Michigan Public Service Commission argued that MISO's refile "still gives rise to discrimination [and] lacks sufficient enforcement of shovel readiness and project completion." It said MISO's plan to cap the megawatt value of expedited projects at 150% of an identified need might shut out meaningful participation by renewable energy developers. The state commission also complained that MISO's hurried refile and ensuing six-day comment period at FERC didn't allow for stakeholder discussion or modifications based on suggestions. It asked FERC to reject the proposal and direct MISO to turn to its stakeholders to draft a more collaborative solution.

Invenergy protested that MISO's restyled proposal still vests regulators with "nearly unbounded discretion to select projects, without any objective criteria to judge whether such projects are capable of satisfying MISO's resource adequacy needs." It said MISO ignored FERC commissioners' request that MISO retry with a narrowly tailored proposal.

Competitive supplier Vistra Corp., which operates in Illinois, asked that FERC order an amendment to MISO's proposal that gives independent producers until Dec. 1, 2025, instead of Sept. 1, to submit their projects for expedited treatment. It said MISO's timelines are "too aggressive" for independents to contract with customers and meaningfully participate in the fast-track process "on a level playing field."

As they did the first time around, utilities chimed in to reaffirm their support.

WEC Energy Group said the fast track is an "innovative solution" that would address an "urgent need for new generation resources."

Alliant Energy said MISO's existing queue alone doesn't provide a sufficient avenue for bringing critical generation online quickly. It also said MISO's design doesn't run afoul of FERC's open access philosophy because it "does not restrict the type of generation facility that may apply or the entity which can submit." Entergy and Cleco agreed in joint comments that MISO's current framework "is not suited to address the need for immediate new resource additions."

Big Rivers Electric Corp. said the expedited treatment would ensure that load-serving entities "can meet their state-mandated obligations to reliably serve load." It added that MISO's resource adequacy challenges are "concrete and urgent."

Northern Indiana Public Service Co., Ottertail Power Co., DTE Electric, Ameren and Consumers Energy also registered support.

At a June 18 Louisiana Public Service Commission meeting, MISO's Todd Hillman reviewed MISO's additions of the project maximum, the limited number of cycles with a 2027 end date and allocation of projects for some independent power producers and MISO's retail choice areas. He said the combination of those new elements should satisfy FERC's initial concerns with the proposal and should "answer many if not all of their questions."

Commissioner Davante Lewis asked how MISO's fast lane would avoid a "two-tier interconnection system that disadvantages" some projects and favors others.

Hillman said MISO will work simultaneously over the next few years to get its normal queue down to a one-year process. He said MISO is "confident" it can shorten time frames with the help of a new annual megawatt cap, AI-based software and some existing projects moving to the express lane.

"They're moving in parallel; they're not really moving against each other," Hillman said of the regular queue and the express lane. ■

Order to Keep Campbell Plant Running Challenged at DOE and FERC

By James Downing

Legal challenges to the U.S. Department of Energy's order to keep the J.H. Campbell power plant in Michigan open mounted with appeals of the initial order and comments at the case in front of FERC on how to pay for it. (See *Consumers Energy Seeking Compensation for Keeping Campbell Open*.)

Michigan Attorney General Dana Nessel filed a *request* for rehearing at DOE on June 18 and intervened in the FERC docket (*EL25-90*) on June 20.

"The closure of this coal-powered electric plant has been planned for years; the utility made all due preparations to maintain our energy load without it; and the closure has been agreed to and cited in settlements affecting customer costs," Nessel said in a statement. "In particular, if this arbitrary and unlawful order is allowed to stand, the only effect Michiganders will feel will be the pinch in their pockets. The costs of maintaining production at the plant, long since prepared for closure, could be an enormous burden on the ratepaying customers of Consumers Energy."

The rehearing request her office filed argued that the Campbell order "is an unlawful abuse of the department's emergency authority" that it had previously only used in response to natural disasters and requests from grid operators or other governmental bodies. Claims that keeping the plant running this summer responds to an emergency "cannot even bear the mildest scrutiny."

Nessel also argued that MISO has found it has enough power to meet demand this summer. NERC did place the region under "elevated risk" in its summer reliability assessment, but the attorney general said that was not even its highest level of risk in the report, and MISO has regularly gotten that label in reliability assessments this decade. MISO's anticipated reserve margin this summer beats its target and is higher than it has been most of this decade, she said.

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

Why This Matters

Some parties are setting up likely litigation against DOE's order to keep a coal plant in Michigan running this summer with rehearing requests, while the case before FERC is only dealing with who will pay for the plant's operations.

"The order indicates that the department believes it has the authority to decide which power plants may retire and when, not based on the kind of real emergency that has justified past action, but rather based on its own policy preferences," Nessel said. "The department appears to want to place its own judgment about operating reserve margins ahead of MISO's, and its own preference for which resources are employed to maintain resource adequacy ahead of Michigan's."

NERC had mistakenly labeled MISO at "high risk" in its initial assessment based on what it called "mismatched data" from the RTO and said it should be reclassified as "elevated risk." The ERO admitted the mistake after criticism from Independent Market Monitor David Patton, who argued that the report had influenced DOE's decision to keep Campbell open. (See related story, *NERC Responds to MISO IMM's LTRA Criticism*.)

Earthjustice, Sierra Club, the Natural Resources Defense Council, Public Citizen and other groups filed a separate rehearing *request* at DOE.

"The order is based on a profoundly incorrect understanding of the handful of sources it selectively quotes," the groups said. "Those sources, and the order itself, do not support the order's claim of a resource adequacy emergency in any of the various locations at which the order ambiguously gestures."

Keeping the plant running at this point will be costly because Consumers had deliberately minimized investments in it in recent years as it was expected to be retired, they argued. Getting it running could cost tens of millions of dollars, they said.

The same groups made a joint filing at FERC, where the only issue before the commission is who will pay for the power plant. The validity and sufficiency of the order will be addressed through pending requests for rehearing at DOE and, "potentially, litigation thereafter."

"The commission lacks a basis to determine which, if any, utility ratepayers will materially benefit from the Campbell plant's operation pursuant to the department's order," the groups said. "Ratepayers in Michigan, Iowa, Missouri, Wisconsin and other MISO states have met, and are already paying for, their resource adequacy obligations under MISO's commission-approved framework for the order's period."

They argued that consumers in MISO have already secured sufficient resources for this summer, so none of them would be clear beneficiaries of keeping the coal plant open, which means FERC cannot assign costs at this time. The environmental and consumer groups asked FERC to deny the complaint or to hold off ruling on the request for now.

The RTO itself weighed in on the FERC case, saying that while it does not intend to challenge DOE's order, it has procured enough capacity for this summer's demand. It has worked with its members, market participants, state regulators and FERC to ensure reliability going forward.

"MISO continues to work with these parties in the context of anticipated growing demand for electricity, planned electric generating facility retirements and an evolving mix of new electric generating resources to refine processes that address the challenges ahead," it said. "MISO is confident that these collaborative efforts do not require further intervention and will help ensure the region continues to procure sufficient capacity to meet demand."

But the order is in effect, and MISO lacks any current rules to allocate the costs of keeping the plant running, it said.

Northern Indiana Public Service Co. said that while Campbell is the subject of the proceeding at FERC, DOE has already used its emergency powers in PJM and could use them for other plants. NIPSCO supports Consumers' request, but DOE's ongoing use of the authority sheds light on the need for a more universal fix in MISO's tariff.

FERC should direct MISO to come up with more universal rules on cost recovery so it does not have to deal with future requests in a "piecemeal fashion," NIPSCO said. "The circumstances that Consumers Energy has found itself in may very well present themselves to other generators in the MISO region, and without an appropriate rate recovery mechanism, MISO's existing tariff may be unjust and unreasonable." ■

Calpine Sees Support for TCC Auction Proposal from NYISO Stakeholders

By Vincent Gabrielle

Calpine came to the NYISO Installed Capacity Working Group on June 17 with its proposal to create on- and off-peak transmission congestion contract auctions.

The company unveiled its proposal in May to the Budget and Priorities Working Group. (See *Calpine Proposes Time-varying TCCs at NYISO*.)

TCCs allow generators to hedge the congestion component of their output. Jung Suh, manager of ISO analytics for Calpine, said this was important for intermittent resources because of their varying load profiles. Calpine's proposal would reduce the cost of congestion by better aligning it with load and generation behavior and improve the modeling of the system, he argued.

"We just need more granularity in the marketplace," Suh said. "Granularity is transparency, and transparency for the market is a good thing."

Tony Abate of the New York Power Authority asked Suh to clarify how the proposal would improve modeling of the system. Suh replied that TCCs themselves improve modeling the system as a side benefit as they naturally model congestion. But keeping TCCs to 24-hour blocks forces the model to only consider daylong averages, which does not reflect load.

NYISO is the only grid operator not to offer time-granulated financial transmission rights, and one stakeholder wondered why that was. Suh said he wasn't sure: Calpine had made the same proposal five years ago and stakeholders had supported it, but there may have been other, more pressing matters for NYISO that may have overshadowed the project, like integrating the Champlain Hudson Power Express line.

Greg Williams, manager of TCC market operations for NYISO, said that to his recollection, market participants had not ranked the project highly enough five years ago to move forward.

"This one has been on the list for prioritization since 2000, and it just hasn't garnered enough support," Williams said.

Doreen Saia of Greenberg Traurig asked whether there were any provisions in the ISO's governing documents that might come into play if trying to change the structure of the TCC market.

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Why This Matters

NYISO is the only ISO that doesn't have FTR auctions for contracts shorter than 24 hours. Calpine is pushing to have stakeholders prioritize developing this as an ISO project for 2026.

Williams said there was some language that covers the concept of TCCs but that if anything were to go forward, more tariff revisions would probably be needed. He also said there wasn't a credit policy that covers TCCs that has the ability to deal with on- and off-peak products. This would require "substantial revision." It's not impossible, Williams explained, but it would require more work.

"The reality here is that there would be a great deal of additional effort that would be necessary — better policy, software systems and so on — to mode this forward," Williams said.

Another stakeholder said they were worried that NYISO was falling behind the other ISOs in terms of their practices, lending support for updating the TCC market.

Abate also pointed out that the Market Monitoring Unit had already identified issues with the TCC market in the context of the ongoing dynamic reserves project.

"My concern is that … I don't think we can look at this in a vacuum without thinking about the impacts of the changes, the monumental changes, we're already making with dynamic reserves," he said.

Another stakeholder responded to Abate saying they were thinking the same thing, but that is why they supported prioritizing the project. The TCC market would be affected by other changes and needed an update to reflect how intermittent resources and batteries impact the grid. ■

N.J. Launches Ambitious Storage Incentive Program

Plan Aims to Help Energy Shortfall with 1,000 MW of Transmission Scale Supply

By Hugh R. Morley

The New Jersey Board of Public Utilities has launched a storage incentive program, aiming to develop 1,000 MW of capacity to mitigate the state's energy shortfall.

The first phase of the Garden State Energy Storage Program has a goal of developing 350 to 750 MW in transmission scale capacity by October. The agency aims to award the remainder of the first phase capacity by next May.

The program will have a competitive solicitation, according to *the June 18 board order* explaining the plan. Financial support in the form of fixed incentives will be paid over 15 years. The program will be open to stand-alone energy storage projects as well as solar-plus-storage projects. The pre-qualification process will start June 25, and the final bid submission deadline is Aug. 20.

"These projects are essential for mitigating the electric capacity supply crunch that is driving dramatic rate increases for New Jersey customers," according to the order. It adds that "quantitative analysis" by the BPU staff indicates the project will "provide net savings to ratepayers within the first few years of its operation."

Boosting Supply

New Jersey, like other states, faces a potential energy shortfall, which PJM attributes in part to the closure of fossil fuel generators faster than new — mostly clean energy — facilities come online. Surging demand from data centers and electric vehicles exacerbates the problem.

A BPU release said the storage project "directly addresses demand growth and limited supply."

"By strategically investing in energy storage now, we're building a resilient system that can better withstand both man-made and weather-related disruptions," BPU President Christine Guhl-Sadovy said in a release. She added that storage also can "support the critical integration of more clean energy, which is vital for New Jersey's sustainable future and peace of mind."

Democratic legislators and BPU officials argue that solar and storage projects are the quickest and cheapest way to add new electricity generation. Storage can provide power overnight or when the sun is not out, and help meet spikes in demand. The BPU says storage can boost the supply of electricity, thus reducing prices.

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Why This Matters

Like many Atlantic Coast states, New Jersey faces a dual-threat energy crisis. Electricity demand is exploding and fossil-fueled generators are retiring faster than they can be replaced by mostly renewable resources. Battery storage can help mitigate that.

Guhl-Sadovy called the launch of the program a "pivotal moment for New Jersey's energy landscape."

"This isn't just about meeting our climate goals, it's about making sure every family can afford to keep their lights on and their home comfortable," she said.

New Jersey's Clean Energy Act of 2018 requires the state to deploy 2,000 MW of energy storage. The state already has missed a state target of having 600 MW of storage in place by 2021. The BPU said last year the state had just 560 MW of installed storage.

Future Phases

The BPU in 2015 established the Renewable Electric Storage Incentive Program and also offered incentives to solar projects coupled with storage under the agency's Successor Solar Incentive (SuSI) program, neither of which covered the large scale and sweep of the latest program.

The BPU's first version of the Storage Incentive Program (SIP), released in 2022, focused on how to stimulate storage. It since has been modified into the current version through a series of public hearings. (See *Impact of NJ's Storage Plan on Overburdened Communities Questioned*.)

The second phase of the new program is intended to be launched in 2026 but was not approved in the June 18 order. It would "focus on incentives for smaller

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FERC Approves Changes to PJM Capacity Deficiency Rate

By Devin Leith-Yessian

FERC has approved a PJM proposal to revise the penalty rate for resources that are unable to meet their capacity obligation due to a decrease to their accreditation after it receives a commitment in a capacity auction (*ER25-2002*). (See *PJM Stakeholders Endorse Proposals to Rework ELCC Accreditation*.)

The change reduces the penalty rate to match the resource's clearing price, rather than the full deficiency rate taking the greater of 120% of the clearing price or $20/MW-day. The issue was brought before stakeholders after shifts in the expected generation mix and performance data led parameters for the 2025/26 third Incremental Auction (IA) to shift toward higher winter risk. (See "Revised Incremental Auction Parameters Endorsed," *PJM MRC/MC Briefs: Jan. 23, 2025*.)

The higher deficiency rate would remain in effect for resources that cannot meet their obligation due to reductions in installed capacity (ICAP) or testing failures.

PJM argued the approach would continue to incentivize the owners of resources with diminished accreditation to procure replacement capacity to cover their shortfall without being punitive. It also would avoid requiring consumers to pay for capacity that is not expected to be provided.

Even without the deficiency penalty, PJM argued that market sellers still would have an incentive to procure replacement capacity at a cost equal to the clearing price plus expected capacity performance penalties for not meeting their obligation during any capacity deployments.

"Because the capacity market clearing price is a reasonable proxy for the replacement cost of capacity, and a seller's expected net non-performance charges will be strictly greater than zero, due to the risk of non-performance, if they fail to purchase replacement capacity, we find that a rational seller would prefer to purchase replacement capacity under PJM's proposal," the commission wrote in its June 17 order.

Another package rejected by the Markets and Reliability Committee (MRC) would have frozen resources' effective load carrying capability (ELCC) ratings and accredited unforced capacity (AUCAP) at the values used in the base residual auction (BRA), which several stakeholders argued would have put the full brunt on consumers when generators could mitigate the issue by maintaining high performance.

FERC Chair Mark Christie | © RTO Insider

Why This Matters

PJM's effective load-carrying capability model for resource accreditation has been the focus of stakeholders and several filings at FERC. Commission Chair Mark Christie criticized the complexity of the model as a Rube Goldberg machine.

Compared to the prior equivalent forced outage rate demand (EFORd) accreditation paradigm, which considered only generator performance, PJM said the shift to ELCC has widened the factors that can affect a unit's rating to include factors beyond the owner's control, particularly how the load forecast affects seasonal risk. It argued this creates an unhedgeable risk for market sellers that could be mitigated by creating an exception to the deficiency rate.

The commission wrote the filing balanced the benefits of updating ELCC ratings with the latest information between IAs without penalizing resource owners for changes in accreditation that may be driven by factors beyond their control.

"While shifts in capacity accreditation under EFORd were related to an individual unit's performance, shifts in capacity accreditation under ELCC are driven by more complex, system-wide factors that 'are not solely a function of such resource's performance, and may not entirely be within the control of the capacity market seller,'" the commission wrote, citing PJM's filing. "Moreover, prior to PJM's transition to the ELCC methodology, sellers could elect to offer less capacity in the BRA than their full (unforced capacity) to mitigate against potential reductions in a resource's UCAP, whereas under the ELCC methodology, a resource must offer the entirety of its accredited UCAP, which reduces a resource's ability to mitigate against a potential shortfall due to a reduction in accredited UCAP value."

Christie Dissents

Dissenting on the June 17 order, Chair Mark Christie wrote that PJM's proposal leaves little incentive for market sellers to procure replacement capacity and is emblematic of a capacity market design that is under constant repair while failing to deliver reliability at least cost. He cited a protest from the Independent Market Monitor (IMM) finding that the cost to purchase replacement capacity in the 2026/27 and following delivery years would be between $63,875/MW-year and $118,625/MW-year, while PJM analysis found that annual capacity performance penalties would be below $24,156/MW-year in 99% of the scenarios considered.

"What's left is a 'penalty' with no teeth. Without an incentive for generators to honor their capacity commitments, generators have less incentive to make the system reliable, and consumers are left with increased reliability risk in the event of an emergency," he said.

Christie wrote that the proposal constitutes a shifting of risk from resource owners to consumers, a dynamic he argued has presented itself repeatedly in deregulated markets.

"This proposal is only the latest example of the endless Rube Goldberg tinkering with the minute details of the capacity market construct. This time, PJM seeks to 'mitigate' potential ELCC variability. Such tinkering has gone on for years and never reaches a point of stability — every 'fix' makes the market construct more incomprehensible (and as I have said many times, it's an administrative construct, not a market)," he wrote. "The Federal Power Act (FPA) is, at its core, a consumer protection statute, and the principal role of this commission is to ensure consumers have reliable and affordable power. Today's order serves neither of those purposes. On the contrary, I agree with the market monitor, that the revisions approved in today's order — contrary to the FPA and this commission's principal role — inappropriately impose reliability risk on consumers."

PJM stakeholders have formed a senior task force to evaluate several components of ELCC, with a proposal aimed at adding transparency to the process endorsed in May. The task force has shifted its focus on how the winter-skewed risk modeling behind ELCC interacts with the summer-focused capacity emergency transfer limit (CETL). (See "Stakeholders Endorse Proposal to Add Transparency to ELCC," *PJM MRC Briefs: May 21, 2025*.)

IMM Argues Proposal Undermines Reliability

The Monitor argued the proposal would reduce the incentive for market sellers to cover deficiencies resulting from accreditation changes and undermine the purpose of ELCC accreditation, which is to determine the expected reliability contribution for each resource. If resource owners do not procure replacement capacity, the Monitor said system reliability could be implicated.

The Monitor also argued the elimination of the penalty payments would outweigh the benefit load may realize from not paying for capacity PJM determines is unlikely to be dependable. ■

N.J. Launches Ambitious Storage Incentive Program

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energy storage systems connected to local distribution grids, including both "in front of the meter" (grid-connected) and "behind the meter" (residential or commercial) systems, according to the BPU release.

A third phase that would offer transmission performance incentives also is under consideration, but the phase is "currently deferred" according to the order.

Fred DeSanti, executive director of the New Jersey Solar Energy Coalition, said in an email to *RTO Insider* that he understands "the potential good that can come of transmission level storage in terms of helping with the capacity shortfall." But he expressed concern that the funding would come from the Regional Greenhouse Gas Initiative (RGGI).

DeSanti said the state, an energy importer, has reaped most of the benefits it can from participating in the RGGI program. He added that by deferring the behind-the-meter proposal to the second phase of the storage program, the state "misses an opportunity to help this important market" just as it faces the loss of crucial tax credits in the federal budget being shaped by Congress.

Mitigating Ratepayer Pain

The BPU emphasized the way extensive storage capacity could help bring down electricity prices in the state, as the agency also backed a series of initiatives designed to mitigate the impact of the recent 20% hike on the average ratepayer bill.

The board approved changes in the state universal service fund (USF), which provides credits to low- and moderate-tincome ratepayers struggling to pay gas and electricity bills. The board increased the minimum USF benefit from $5 to $20 and the maximum benefit from $180 to $200.

The board order also requires utilities to increase ratepayer enrollment in the program to ensure that more eligible ratepayers benefit. The state's four utilities are required to increase by 5% their enrollment in the program during the year from October 2024 to September 2025. They should increase enrollment by 3% in the second year and by 2% in the third year, according to the plan.

The changes are expected to affect 136,000 existing customers who receive the minimum benefit and an additional 8,000 who receive the maximum benefit, according to the BPU. The utility enrollment efforts are aimed at the 80% of eligible household that are not signed up for the benefit.

The changes will cost about $28.5 million, which will be paid with existing funds, the board said. ■

Pennsylvania Brings Seasonal Capacity Issue Charge to PJM

By Devin Leith-Yessian

The Markets and Reliability Committee (MRC) discussed a *problem statement* and *issue charge* brought by Pennsylvania Gov. Josh Shapiro (D) to open a discussion on establishing a sub-annual capacity market design.

Presenting the proposal to the committee on June 18, Deputy Secretary of Policy Jacob Finkel said the issue charge calls for a senior task force to be established to work toward a seasonal design with the aim of PJM filing a proposal at FERC in the first quarter of 2026. That timeline targets implementation in the 2029/30 Base Residual Auction (BRA), which Finkel said is a tight timeline but an important goal for fixing an annual capacity market design that overcharges ratepayers and blunts market signals.

Christian McDewell, of the Pennsylvania Public Utilities Commission, said the commonwealth supported a seasonal design during the 2023 Critical Issue Fast Path (CIFP) process focused on long-term resource adequacy. He recognized, though, that more work was needed to arrive at a workable proposal. (See *PJM Stakeholders Vote Against All CIFP Proposals*.)

"I think that it's a good thing to look at this. We've been moving in fits and starts … toward what looks like a sub-annual market," he said.

Why This Matters

Pennsylvania's proposal to explore a sub-annual capacity market design at PJM comes as member states have grown critical of the capacity market design and how it balances resource adequacy against consumer rates. The commonwealth entered a settlement with PJM earlier this year to lower the maximum clearing price and establish a minimum price.

Adam Keech, PJM | © *RTO Insider*

Several stakeholders expressed skepticism that such a major market overhaul can be completed in six months.

Paul Sotkiewicz, president of E-Cubed Policy Associates, said past CIFP processes and the implementation of effective load-carrying capability (ELCC) for resource accreditation have shown what happens when stakeholder deliberations are accelerated. While developing a seasonal market design is a great idea, he said it likely would take at least two years to get right.

PJM Vice President of Market Design and Economics Adam Keech said February is the latest PJM could make a filing with the expectation that FERC could issue a favorable order in time for the 2029/30 BRA pre-auction. That assumes there are no deficiency notices. There also would be a non-trivial amount of time needed for software development and testing to effectively split the capacity market in half.

Asked if the implementation could be done in a phased approach, Keech said that would need to be done logically to not have a "Frankenstein" transition period.

Middle River Power's Sophia Dossin said MISO moved recently to a four-season auction after a considerably longer stakeholder process and still had a rocky implementation. She questioned whether the governor's office is open to making sure the timeline does not supersede the quality of the product.

Finkel responded that the commonwealth sees implementation in the 2029/30 auction as an important goal but does not want to put the timeline over all else. Getting started is what's most important, he added.

He said a seasonal market was discussed in 2006 and 2018, as well as during the 2023 CIFP process, making it frustrating that it's viewed as something that will take an extended period of time.

NRDC Senior Advocate Tom Rutigliano said the energy landscape is changing rapidly, but PJM has difficulty adjusting its capacity market on an agile timeline. It takes time for processes to work their way through the stakeholder process, the commission and then be implemented in a forward auction. If PJM does not become more responsive, he said, it will continue to operate between crises.

Susan Bruce, representing the PJM Industrial Customer Coalition, said consumers are concerned about many of the same issues as the commonwealth. Implementing a seasonal market could affect other market components in ways that are difficult to predict at the onset, she said. She compared the capacity market to a tapestry in which pulling on one thread affects the larger design.

While there have been a lot of studies on how a sub-annual market could function in PJM, Bruce said much of that work was done at a time when PJM had excess capacity.

"What does a seasonal construct look like in a world where we are tight all four seasons?" she asked.

Vitol's Jason Barker said he's worried about the implications of a problem statement that includes value statements about the potential cost impact of shifting to a seasonal auction when it is not known how such a change would affect pricing.

Finkel said the commonwealth is less concerned about the dollar amount than it is about ensuring the market accurately reflects what is happening in the real world.

Representing the PJM Public Power Coalition, Customized Energy Solutions' Carl Johnson said PJM presented a capacity market design road map in July 2024 showing concurrent work on a more granular market and possible rethinking of the forward auction. He said it would make sense for the two issues to be discussed together to arrive at a holistic solution.

Finkel responded that both are important issues, but the Reliability Pricing Model is not as effective as it could be with an annual design, which is a discrete topic he said other RTOs have managed to address.

Exelon's Alex Stern lauded the governor's office for bringing the proposal, saying everyone benefits when the member states are involved in the stakeholder process. Throughout his time participating in PJM, he said this is the first time he can recall a state bringing its own issue charge and being involved in this manner. While it may not be possible to arrive at a proposal in time for the 2029/30 auction, he said it's worthwhile to try.

"Even if it's not all four seasons … a seasonal market design, in my mind, can better reflect the actual seasonal variations in supply," Stern said.

Rory Sweeney, of the Northern Virginia Electric Cooperative, questioned whether the governor's office would be satisfied if the stakeholder process resulted in support for the status quo. Finkel responded that it's important to let that process play out and see where the membership lands. The outcome could be viewed differently if there is broad support across all sectors or a divided stakeholder body. ■

PJM Stakeholders to Examine Rules for Future DOE Emergency Orders

MC Recommends Cost Allocation Method for Eddystone

By Devin Leith-Yessian

VALLEY FORGE, Pa. — Looking ahead to the possibility of future emergency orders from the U.S. Department of Energy, stakeholders endorsed a PJM *issue charge* to establish a more permanent set of rules for how to allocate the cost of keeping generation online beyond its desired deactivation date when ordered by the federal government.

PJM Executive Director of Member Services Jennifer Tribulski told the Markets and Reliability Committee on June 18 that the RTO envisions a new senior task force meeting two to three times a month, with a goal of submitting a filing to FERC in October.

The issue charge designates the content of future DOE orders and the "operating protocols and parameters agreed to by the resource owner" as out of scope.

The Members Committee voted to support a proposal to assign all PJM consumers a share of the cost of continuing to operate Constellation Energy's Eddystone Generating Station. The company was ordered by DOE to keep Eddystone online past its May 31 deactivation date to ensure resource adequacy, but the order did not specify how Constellation should be compensated. (See *PJM Stakeholders Propose Cost Allocation Models for DOE Emergency Orders*.)

The package from Gabel Associates received 86% sector-weighted approval in the June 18 vote, making it the only proposal to receive the committee's support over two proposals from PJM and three from the East Kentucky Power Cooperative (EKPC). The vote results are advisory to inform the PJM Board of Managers' determination on how to proceed.

Stakeholders commented on the proposals to the board in a Critical Issue Fast Path (CIFP) meeting, which was closed to media and held after the MRC meeting but just before the MC vote. The CIFP process was conducted on a tight five-day timeline to avoid a gap in billing.

Adrien Ford, Constellation | © *RTO Insider*

All of the proposals include the same June 1 implementation date, transparency provisions, billing frequency and cost allocation calculation formula. Where they differ is how to determine which consumers should be allocated a share of the costs and whether the governing document revisions should address possible future DOE emergency orders.

Gabel's proposal, PJM Package C and EKPC Package E would allocate the costs to all PJM consumers, while PJM's Package A would narrow the allocation to specific locational deliverability areas (LDAs) or zones if future emergency orders specified that a resource adequacy issue was geographically isolated. EKPC Packages D and F would allocate the costs to specific LDAs if they clear short of their reliability requirement; otherwise, they would use an RTO-wide allocation.

Gabel and EKPC Package E both would apply only to the Eddystone order expiring in August, with the other five including differing ways of addressing any future emergency orders to keep generation online.

Constellation Vice President of Wholesale Market Development Adrien Ford said the company could not support Gabel's proposal without modifications to allow it to continue to provide cost allocation beyond the Aug. 28 expiration of the DOE order in the event the department requires Eddystone to remain online longer.

Exelon Director of RTO Relations and Strategy Alex Stern said he supports the Gabel proposal and trusts the board to make any necessary adjustments, such as the applicability to future orders.

Carl Johnson, representing the PJM Public Power Coalition, said some members supported the Gabel proposal because it would limit the changes to the current Eddystone order, with the belief that there will be more emergency orders issued in the next few weeks and those should be addressed as they come up. ■

PJM MRC/MC Briefs

Markets and Reliability Committee

Dominion Presents Proposal to Change Dual-fuel Definition

VALLEY FORGE, Pa. — Dominion Energy presented the Markets and Reliability Committee with a quick-fix *package* to expand the definition of dual-fuel generation in the Reliability Assurance Agreement (RAA) to include generation capable of running on a backup fuel type with off-site storage and dedicated delivery.

The current language restricts the dual-fuel classification to gas combustion turbines or combined cycles capable of starting and operating on an alternative fuel with on-site storage. Dominion's James Davis said that would exclude an LNG storage facility the company is building in Virginia. Dedicated pipelines would run from storage to two CC generators, a configuration not recognized as dual-fuel under the existing rules, but which Davis said provides a comparable degree of reliability.

The quick-fix process allows a *problem statement*, issue charge and proposal to be brought concurrently. The proposal would be effective for the 2028/29 Base Residual Auction (BRA), the schedule of which has fuel-type attestations due in November.

Calpine's David "Scarp" Scarpignato said the proposed language could loosen the definition of fuel source to allow configurations that would not deliver the reliability expected from dual-fuel units. When Calpine proposed changes to the dual-fuel definition in 2024, the Independent Market Monitor recommended changes to the proposed language to ensure the backup fuel actually could be used. Scarp gave the example of a generation owner seeking dual-fuel status for a resource with a small on-site storage tank intended to be resupplied by truck as needed. (See "Quick Fix for Dual-fuel Classification Endorsed," *PJM MRC Briefs: April 25, 2024*.)

PJM Board of Managers Chair David Mills speaks at the June 18 Members Committee meeting. | © *RTO Insider*

Stakeholders Bring Alternative SATA Issue Charges, Endorsement Delayed

The committee deferred voting on an *issue charge* seeking to establish a ruleset for battery storage to be installed and operated as a transmission asset (SATA) to allow more time to consider two alternatives brought by Constellation and Exelon.

The PJM issue charge has been discussed at several meetings in recent months, with voting delayed to hold education on how SATA would operate and its implementation in other RTOs.

Building off PJM's issue charge, Constellation *added* several key work activities (KWAs) to identify the use case for SATA, when the batteries would run and more thoroughly consider the market effects storage might have. Stakeholders seeking more consideration of the topic before voting on an issue charge have argued inadequate rules could allow batteries on a regulated rate to displace market-based resources.

Independent Market Monitor Joe Bowring has said in past meetings there is not a way to meaningfully distinguish between a resource injecting energy for transmission support or market participation.

Exelon *proposed* edits to the Constellation language focused on ensuring SATA would be treated and used the same as other transmission solutions. It replaced a Constellation KWA to "identify what the market impacts could be and a commitment to address them" with "ensure a storage device identified as transmission only and not a market resource is treated no differently than any other transmission asset, including with respect to market impacts."

1st Read on 3rd Phase of Hybrid Resource Rules

PJM presented *revisions* to several manuals to conform with FERC's approval of the third phase of PJM's hybrid resource rules (*ER25-1095*). Elements of the manual changes were endorsed by the Planning, Operating and Market Implementation Committees earlier in June. (See "3rd Phase of Hybrid Resource Rules Endorsed," *PJM MIC Briefs: June 2, 2025*.)

Phase 3 expands the hybrid model to include pairings of co-located non-inverter-based generation and battery storage as one market unit. Hybrids with a capacity commitment would fulfill their obligation to offer into the energy market by submitting their forecast output, capped at the inverter capability, while a hybrid with a storage component should offer the "anticipated intermittent and battery output."

Revisions to the formula for lost opportunity cost (LOC) credits would make eligible storage and hybrid resources instructed to increase charging to mitigate transmission constraints or reliability issues. Resources instructed to reduce charging would not be eligible.

The definition of closed- and open-loop batteries also would be revised to allow resource owners to determine how a storage unit should be classified. For instances where storage is capable of charging from the grid, the resource owner would be permitted to choose whether to offer it as open- or closed-loop, allowing for situations where a battery is physically capable of charging but the owner has determined not to operate it in that fashion.

PJM Presents Capacity Market Manual Revisions

PJM presented a first read on proposed *revisions* to Manual 18: PJM Capacity Market to conform with several filings the RTO has made in recent months reworking elements of the market (*ER25-682*, *ER25-785*, *ER24-2995* and *ER25-1357*).

The changes include modeling the expected output of some resources operating on reliability-must-run agreements as capacity; implementing a minimum capacity market clearing price and lowering the price maximum; removing the addback for energy efficiency resources; codifying the BRA schedule; maintaining a CT as the reference resource; and setting an RTO-wide capacity performance penalty rate. The revisions also would remove an exemption from the requirement that resources offer into the capacity market for intermittent, storage and hybrid resources. (See *FERC OKs Changes to PJM Capacity Market to Cushion Consumer Impacts*.)

Members Committee

Board to Hold Dialogue with Stakeholders at MC Meetings

PJM Board of Managers Chair David Mills told the Members Committee that attending board members will remain at the Conference and Training Center (CTC) for the full meeting to facilitate a dialogue with stakeholders. That includes a commitment to remain in the region overnight to allow discussions to continue after the MC concludes. Mills was joined by board members Paula Conboy and Vickie VanZandt at the CTC, with other members attending virtually.

"This is an opportunity for us to hear out one another. And all this is against the backdrop of our responsibility as board members .... to hear what you have to say," Mills said, adding that listening to stakeholders does not mean the board will take sides on issues or compromise its independence.

At the Annual Meeting on May 12, Mills broached the idea of adding a standing MC agenda item for the board and stakeholders to bring issues they wish to discuss. Several stakeholders cited lacking transparency and access to the board as their reason for voting against re-electing two board members during the meeting. (See *PJM Stakeholders Vote Out 2 Board Members*.)

Much of the discussion during the June 18 meeting centered on the format future discussions should take, with the aim to have them begin in earnest at the July 23 MC meeting. Mills said his vision is for the format to be more informal than that of the Liaison Committee (LC), with conversations rather than prepared speeches. That could take the form of moving to group conversations in the lobby or remaining in the conference room.

PJM Proposes Revisions to Antitrust Language

PJM Assistant General Counsel Eric Scherling *presented* updated antitrust guidance for stakeholder meetings intended to bolster the RTO's recommendations for avoiding conduct that could run afoul of antitrust law. He characterized the guidance as a clarification, rather than a change, in the language.

The changes affect the antitrust language included in meeting agendas, which are referenced by committee and stakeholder group chairs before meetings begin, as well as guidance on the PJM website. Scherling said the change in guidance is not in response to any particular stakeholder behavior, but rather making improvements that PJM has identified.

While stakeholders can discuss how trends and forecasts may affect market pricing or costs, disclosure of non-public information, such as bidding practices, could violate federal antitrust statutes. The guidance states that "informal, hypothetical or joking references to these topics should be avoided."

Scherling said there are a pair of protected areas where market practices or non-public information could be discussed without violating federal law. The Noerr-Pennington doctrine allows for good-faith advocacy for federal agencies to adopt proposals that may reduce the competitiveness, while Parker immunity allows uncompetitive activity so long as it is authorized by state policy.

Changes to Liaison Committee Registration Discussed

PJM plans to close registration for future LC meetings a few days in advance to ensure staff have time to validate the credentials of attendees ahead of time, Manager of Stakeholder Process and Engagement Michele Greening said.

For the July 28 meeting, that means registration will close at 5 p.m. July 24, with no late registrations accepted.

Constellation Vice President of Wholesale Market Development Adrien Ford said prior to the COVID-19 pandemic, the LC meeting was a great opportunity for members to speak with the PJM Board of Managers about pressing matters and network with other attendees afterward. In-person attendance has not returned to pre-pandemic levels, however, and there have been fewer meetings recently, making the committee a less rich experience.

PJM CEO Manu Asthana said part of why there have been fewer LC meetings is the board has been meeting more regularly to address pressing issues as they arise. ■

FERC Accepts Revisions to SPP's WEIS Market

By Tom Kleckner

FERC has accepted SPP's tariff revisions for its Western Energy Imbalance Service (WEIS) market that allow the grid operator to begin a market hold for reliability-based concerns when requested by a balancing authority (*ER25-1137*).

In its June 20 order, the commission found the proposed tariff revisions to be just and reasonable and accepted them effective April 5, 2025. It said the changes will help facilitate the *WEIS market*'s operation by specifying that SPP will suspend the calculation of dispatch instructions for certain resources and treat them as self-dispatched if a participating BA asks for a market hold.

FERC said the changes allow the WEIS market's relevant entities — the participating BAs, the SPP West Reliability Coordinator and SPP as the market operator — "to coordinate and timely respond to reliability-based events while avoiding significant disruptions to the operation of the WEIS market and providing clarity regarding settlements for the time period of those events."

It noted that "importantly," the BAs and SPP West RC "retain their NERC-mandated reliability responsibilities in the WEIS market."

SPP's Market Monitoring Unit protested the tariff revisions, saying they were not clarifying in nature. The MMU said a market hold initiated by a BA for reliability-based concerns is instead a new condition that would suspend the market dispatch.

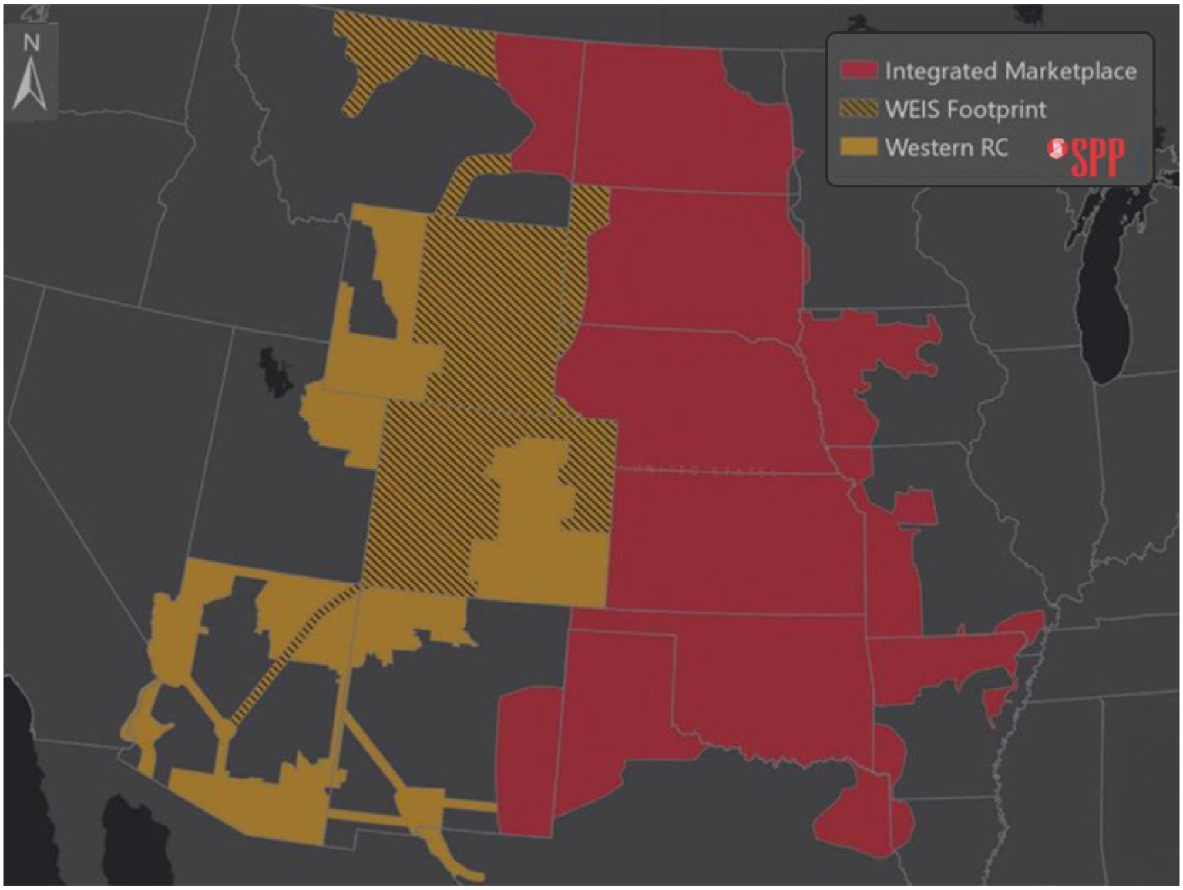
The Monitor said that while a BA should be able to initiate the hold, a lack of detail in two key areas rendered the proposed revisions unjust and unreasonable. It argued they have neither clear guidelines for the types of reliability concerns that would trigger a market hold nor an explanation of the actions that should be taken leading up to and after the market hold. It also asserted that the proposals lack transparent communication to market participants.

FERC disagreed, finding that a "reliability-based concern" is appropriate because the BAs are the entities ultimately responsible for initiating market holds in their respective areas. It noted that SPP said a market operator does not have authority to dictate what BAs can and cannot do for reliability reasons, pointing to a list of examples of reliability-based concerns that could warrant a market hold.

"These examples illustrate that there are myriad operational issues that could pose a risk to reliability," the commission said. "We recognize a balancing authority's responsibility to maintain reliability in the face of a wide range of potential operational issues and the necessary flexibility required to adequately do so."

The commissioners were also "unpersuaded" by the MMU's contention that the revisions are unjust and unreasonable because they fail to set forth an expectation that the BAs will exhaust alternative solutions before implementing a market hold. FERC found that the tariff doesn't need to "set forth such an expectation in order to be just and reasonable because the tariff does not govern balancing authorities' responsibilities to ensure reliability." Those responsibilities are governed by the applicable reliability standards, it said.

SPP has administered the WEIS market on a contract basis since February 2021, balancing generation and load for 12 participants, primarily in the Rocky Mountain region. The RTO has said the market participants will eventually transition to either its Western RTO expansion or its Markets+ program. (See *SPP to Phase Out WEIS as New Market Offerings Expand*.) ■



SPP's Western Energy Imbalance Service market | *SPP*

Tri-State Tells Colorado PUC Joining SPP RTO in Public Interest

RTO Participation Will Bring Significant Benefits, Tri-State Says

By Henrik Nilsson

Tri-State Generation and Transmission Association asked the Colorado Public Utilities Commission to find it would be in the public interest for the power supplier to join SPP, saying integrating with the RTO will bring significant benefits.

Tri-State said in a June 17 news release that it is preparing to fully integrate with SPP's RTO West expansion in April 2026 together with six other Western utilities and that it has filed an *application* for a public interest determination with the commission.

By joining the RTO, Tri-State would bring resources located in the power supplier's Colorado, Nebraska and Wyoming Western Interconnection system, totaling over 20 generating units, more than 3,100 miles of high voltage transmission and portions of 23 of Tri-State's members' loads, "representing 67% percent of gross load across the Tri-State system," according to the release.

Additionally, Tri-State touted the benefits of joining the RTO, saying it will bring an estimated $20 million in annual net benefits and increased ability to meet energy demand and greenhouse gas reduction targets, among other benefits.

Tri-State headquarters in Westminster, Colo. | *© RTO Insider*

"The expansion of the SPP RTO is the most cost-effective pathway to organized market benefit for Tri-State's members," Duane Highley, Tri-State's CEO, said in a statement. "Our participation will support our members' goals for reliability, affordability and a cleaner energy future, with cost savings shared by all members."

"SPP welcomes Tri-State's announcement about their expanded participation in the SPP RTO," Carrie Simpson, SPP vice president of markets, told RTO Insider. "As a long-standing SPP member and key energy provider in the West, Tri-State's deeper involvement strengthens our shared commitment to responsibly and economically keep the lights on today and in the future."

"This announcement formalizes plans announced years ago and applies only to Tri-State's Colorado facilities outside the Xcel system. It does not impact Tri-State's continued participation in Markets+ for facilities within Xcel," Simpson added.

FERC on March 20 accepted SPP's proposed revisions to its tariff that will incorporate seven Western Interconnection entities as transmission-owning members of the RTO, making the grid operator the first to provide full market services in the grid's two major interconnections. (See *FERC Approves Tariff for SPP RTO West*.)

SPP has targeted April 2026 as when the entities, including Tri-State, will begin participating in its Integrated Marketplace, transmission planning, reliability coordination and other RTO services. They all are members of the Western Energy Imbalance Service market, which SPP has administered since 2021:

- Basin Electric Power Cooperative
- Colorado Springs Utilities
- Deseret Power Electric Cooperative
- Municipal Energy Agency of Nebraska

Why This Matters

Tri-State is hoping that joining the RTO will bring millions of dollars in benefits and solve seams issues.

- Platte River Power Authority
- Western Area Power Administration

SPP has said RTO West will provide more than $200 million in annual benefits to its members, primarily through the optimization of DC ties with the Eastern Interconnection.

In the June 17 news release, Tri-State said the RTO will reduce seams between providers in "Colorado, Wyoming, Montana and Nebraska through the consolidation of seven transmission providers' tariffs into an SPP RTO common tariff, also reducing the costly "pancaking" of transmission rates."

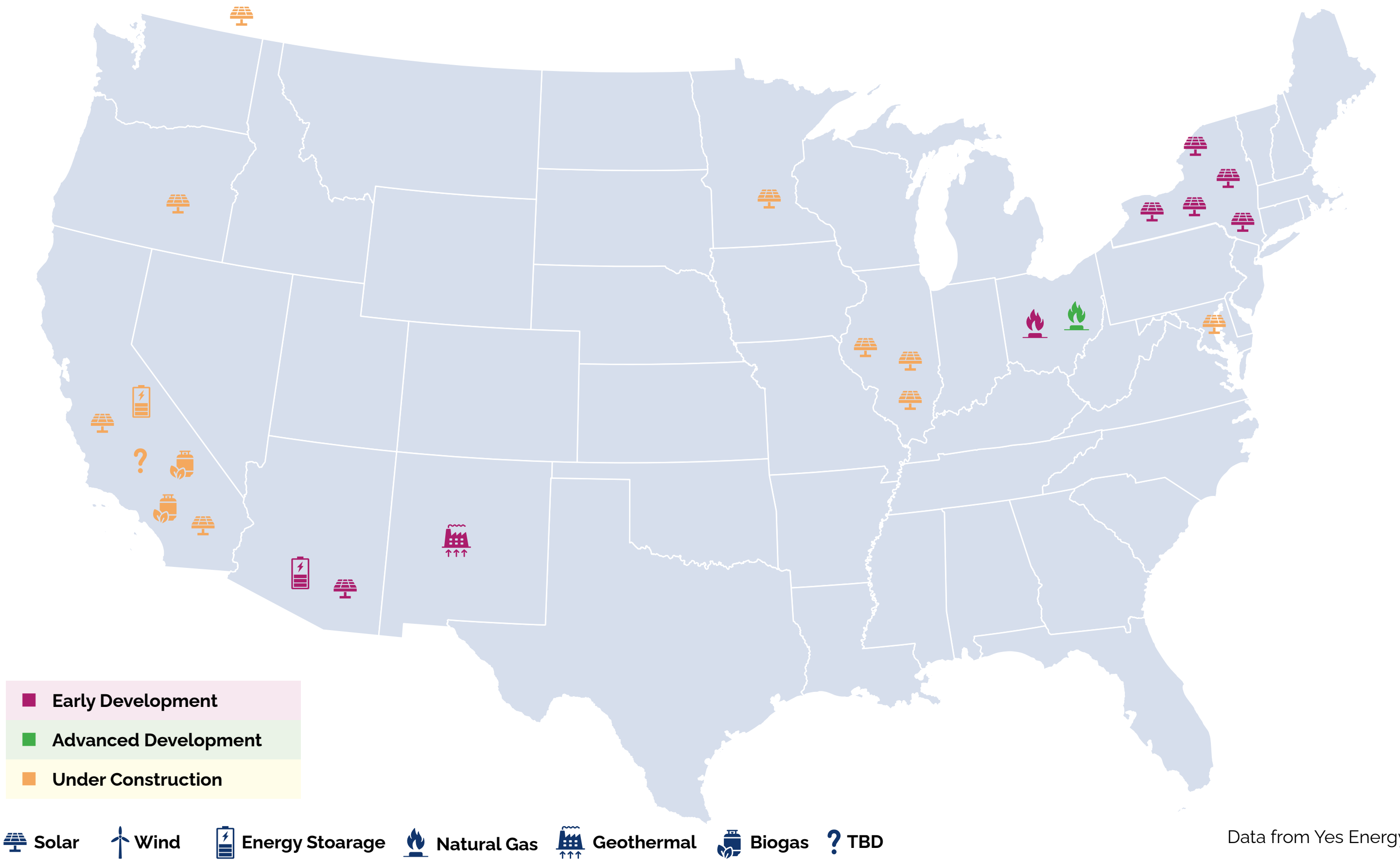
Tri-State noted that seams will continue to exist between the Western Area Power Administration's Colorado-Missouri balancing area and that of the Public Service Company of Colorado, which is seeking to join SPP's Markets+ day-ahead market offering. (See *PSCo Seeks to Join SPP's Markets+*.)

Tri-State has been one of the signatories to a series of "issue alerts" touting the purported advantages of Markets+ over CAISO's extended day-ahead market and the Western Energy Imbalance Market (WEIM). (See *7th 'Issue Alert' Highlights Markets+ Footprint*.)

"We greatly value the full benefits of the SPP RTO, including day-ahead, real-time and ancillary services markets, efficient regional transmission planning, reliability coordination, a common transmission tariff and a participatory governance model that help us reduce costs and advance clean energy goals," Highley said. ■

Generation Projects Added in the Past Week

YES ENERGY.

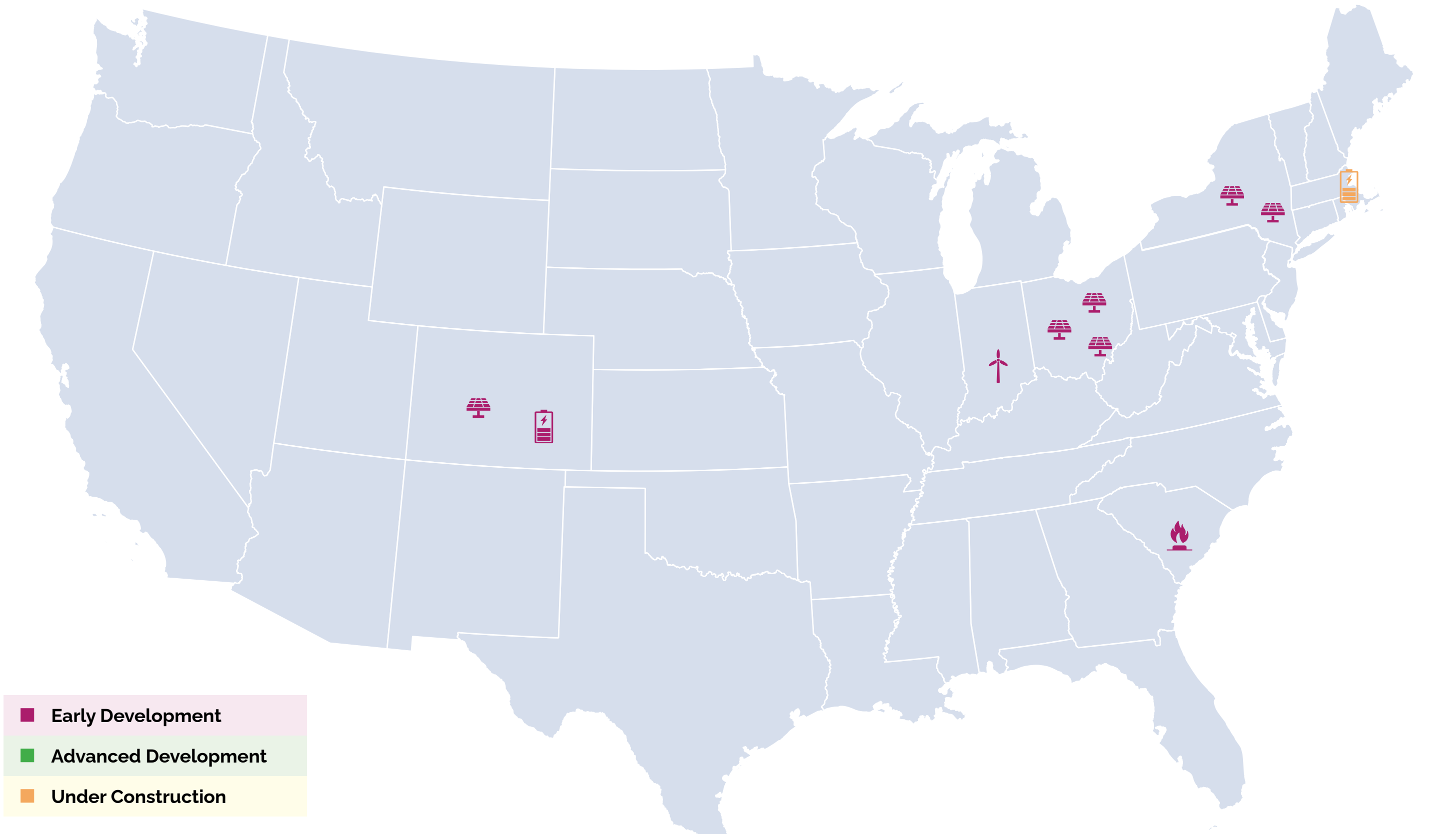


Data from Yes Energy

Project or Unit Name	Holding Company or Parent Organization	Primary Energy Source	State or Province	Capacity (MW)	In Service Year
XGS NM Geothermal Phases I & II (unofficial name)	XGS Energy	Geothermal	NM	150	2030
Anahim Lake Solar Project	Ulkatcho Energy Corporation	Solar	BC	4	2026
Ore Town Solar	EIG Management Company	Solar	AZ	145	2027
Ore Town Solar BESS	EIG Management Company	Energy Storage	AZ	145	2027
Socrates North Power Generation	Williams Company	Natural Gas	OH	200	2026
Socrates South Power Generation	Williams Company	Natural Gas	OH	200	2026
Airport Commons 7-slbal210 11684	Ownership Undisclosed	Solar	MD	1	2025
Bavaria Solar LLC BEIER	Ownership Undisclosed	Solar	MN	1	2025
Cavern PV1	Ownership Undisclosed	Solar	NY	2	2026
CPA Dominguez - SLLAX901 LA901	Ownership Undisclosed	Solar	CA	1	2025
Endicott PV1	Ownership Undisclosed	Solar	NY	5	2026
Glen Mary PV1	Ownership Undisclosed	Solar	NY	3	2026
Godinho Dairy Digester GEN1	Ownership Undisclosed	Biogas	CA	1	2025
Godinho Dairy Digester GEN2	Ownership Undisclosed	Biogas	CA	1	2025
OR - Chapman Creek - Greenkey CHPMN	Ownership Undisclosed	Solar	OR	3	2025
Richmond Solar HM701	Ownership Undisclosed	Solar	IL	2	2025
SAE Taylorville IL S1 S1	Ownership Undisclosed	Solar	IL	1	2025
Tracy Renewable Power Plant TRP01	Ownership Undisclosed	TBD	CA	5	2027
Tully 4 PV1	Ownership Undisclosed	Solar	NY	5	2026
Tully 5 PV1	Ownership Undisclosed	Solar	NY	2	2026
USS University Park Solar USSUP	Ownership Undisclosed	Solar	IL	2	2025
Visalia - (CA) VISB	Ownership Undisclosed	Energy Storage	CA	1	2025
Visalia - (CA) VISS	Ownership Undisclosed	Solar	CA	4	2025

Generation Projects Added in the Past Week

YES ENERGY



Solar | Wind | Energy Stoarage | Natural Gas | Geothermal | Biogas | ? TBD

Data from Yes Energy

Project or Unit Name	Holding Company or Parent Organization	Primary Energy Source	State or Province	Capacity (MW)	In Service Year
Wakefield MA BESS 1 90914	Ownership Undisclosed	Energy Storage	MA	5	2025
Watson 1 PV1	Ownership Undisclosed	Solar	NY	5	2026
Watson 2 PV1	Ownership Undisclosed	Solar	NY	5	2026
City of Brooklyn Landfill Solar Phase 2	CEP Renewables	Solar	OH	5	2026
Harvard Road Landfill	CEP Renewables	Solar	OH	3	2026
Montrose Battery Storage	Tri-State Generation and Transmission	Energy Storage	CO	50	2026
SMPA Solar	Touchstone Energy Cooperatives	Solar	CO	20	2100
Prairie Creek Wind	RWE	Wind	IN	203	2027
Wombat Solar	Geenex LLC	Solar	OH	400	2029
Anderson Natural Gas Plant	Duke Energy	Natural Gas	SC	1,400	2031

Company Briefs

Constellation-Calpine Merger Clears N.Y., Texas Review

Constellation's previously announced acquisition of Calpine has been approved by the New York State Public Service Commission. The approval comes more than a week after the deal cleared Texas regulatory review.

In January, Constellation announced plans to acquire Calpine in a cash and stock transaction valued at an equity purchase price of $16.4 billion.

The transaction, which is expected to close in the fourth quarter of 2025, now awaits approval from FERC and the Department of Justice.

More: *Power Engineering*

Engie Launches Pilot PPA-tied Solar Panel Recycling Program

The North American unit of French power utility Engie SA has launched a pilot program that integrates the recycling of solar panels and related components into power purchase agreements.

The approach, dubbed "precycling," will enable developers to recycle almost one million panels when their operational lifespan expires and divert them from landfills, the company said. The initiative concerns four photovoltaic projects in the Midwest with a combined capacity of 375 MW.

The program was developed in partnership with solar panel recycler Solarcycle. According to estimates, the incorporation of this provision into the PPAs will divert 48 million pounds of material from landfills and avoid about 33,000 tons of carbon emissions.

More: *Renewables Now*

AEP Announces Executive Leadership Changes

American Electric Power last week announced leadership changes to support its long-term strategy.

The company named Rob Berntsen executive vice president and general counsel, effective July 14. He will succeed David Feinberg, who will serve as senior adviser to the chief executive officer until departing the company Aug. 15.

Additionally, AEP named Johannes Eckert executive vice president and chief information and technology officer, effective July 21.

More: *AEP*

Federal Briefs

Judge to Deny Admin's Motion to Dismiss Dismiss Wind Block Lawsuit

Judge **William G. Young** last week said he plans to deny a motion by the Trump administration to dismiss a lawsuit over its blocking of wind energy projects, siding with a coalition of 17 state attorneys general.

Young said during a hearing that he plans to allow the case to proceed against Interior Secretary Doug Burgum but will dismiss the action against Trump and cabinet secretaries other than Burgum named as defendants. Young said he believes states have standing to sue and can proceed with claims that blocking permits for wind projects violates the Administrative Procedure Act, which outlines a detailed process for enacting regulations, but not the Constitution.

Young said his rulings from the bench were tentative and reserved the right to alter them in writing his formal opinion.

More: *The Associated Press*

SCOTUS Clears Way for Temp Nuke Waste Storage Sites

The Supreme Court last week voted 6-3 to reverse a federal appeals court ruling that invalidated the license granted by the Nuclear Regulatory Commission to a private company allowing it to temporarily store nuclear waste in Texas. The outcome is expected to reinvigorate plans for a similar facility in New Mexico.

The justices did not rule on a more substantive issue: whether federal law allows the commission to license temporary storage sites. The NRC has said the temporary storage sites are needed because existing nuclear plants are running out of room.

The licenses would allow the companies to operate the facilities for 40 years with the possibility of a 40-year renewal.

More: *The Associated Press*

$1.4B in Solar, EV, Storage Developments Canceled in May

Businesses canceled an additional $1.4 billion in new factories and clean energy projects in May, according to E2's latest monthly analysis of clean energy projects.

The latest cancellations mean $15.5 billion in new factories and electricity projects have been cancelled since Jan. 1.

More than $9 billion of those investments have been canceled, delayed or closed in Republican districts. Through May, 62% of all clean energy projects announced — along with 71% of all jobs and 82% of all investments — are in congressional districts represented by Republicans.

More: *Solar Power World*

State Briefs

IOWA

House Votes to Go in Special Session to Override Veto of Pipeline Bill

The state House of Representatives last week secured the necessary two-thirds majority on a petition calling for a special session to override Gov. **Kim Reynolds**' veto of a bill pertaining to eminent domain and carbon sequestration pipelines.

Seventy representatives signed the petition in favor of returning to the state Capitol to override the veto, but two-thirds of the Senate will also have to sign on for a special session to be called. The bill would have restricted the use of eminent domain for carbon sequestration pipelines and added a slew of additional requirements for pipelines and the regulator.

More: *Iowa Capital Dispatch*

MAINE

State Codifies New Goal of 100% Clean Energy by 2040

State lawmakers last week passed a bill that moves up the timeline to reach net zero carbon emissions.

The new law would require the state's energy office to expand its existing Renewable Portfolio to 90% by 2040, focusing on rooftop wind, solar and battery storage. The remaining 10% will be dedicated to a new category of clean resources, like hydropower.

A previous law had set a goal of 100% clean energy by 2050.

More: *Maine Public Radio*

NEW YORK

Avangrid Senior VP Harriman Appointed to NYSERDA Board

Avangrid last week announced that Kimberly Harriman, its senior vice president of public and regulatory, has been appointed to the board of the New York State Energy Research and Development Authority (NYSERDA).

Harriman joined Avangrid in 2020 as the company's vice president of state government relations and public affairs.

Harriman was nominated by Gov. Kathy Hochul and confirmed by the state's Senate.

More: *SolarQuarter*

Staten Island Ferry Fleet Converting to Renewable Diesel Early

The Staten Island Ferry's vessels are converting to renewable fuel ahead of schedule, city officials announced last week.

The city's first delivery of 336,000 gallons of renewable diesel reached Staten Island last week as the city plans to begin running all 10 of the boats on it. The fuel, which has been used by the city's municipal motor pool for more than a year, is a blend of alcohols, oils, fats and hydrogen.

City officials originally anticipated running all ferries on the fuel by January 2026.

More: *New York Daily News*

TEXAS

CenterPoint, Cities Agree to $3.2B Plan to Upgrade Houston-area Grid

CenterPoint Energy last week announced it reached a settlement with various Houston-area cities to spend $3.2 billion to fortify its local grid infrastructure against extreme weather and other hazards from 2026 to 2028.

The money would go toward installing more storm-resilient utility poles, burying more power lines and stepping up tree trimming, among other improvements. Once completed, the improvements would prevent nearly a billion minutes of outages for area homes and businesses by 2029, according to the announcement.

CenterPoint said the plan would add about $1.40/month to the average residential bill each year from 2026 through 2028. An additional 60 cents would be added in 2030 "to help lessen bill impacts in previous years," according to the company's statement.

More: *Houston Chronicle*

VIRGINIA

Chesapeake City Council Rejects Data Center Proposal

The Chesapeake City Council last week voted unanimously to reject a proposed 350,000-square-foot data center.

After two-and-a-half hours of public comments, the council voted 7-0 to ignore a request from the center's developer to delay the vote until later this summer and denied the rezoning request.

More: *WHRO*

Suffolk Approves New Solar Farm Rules

The Suffolk City Council last week approved new sound and setback rules for solar farms.

The rules mandate a greater distance between a farm's inverters and the property line. New farms will have to place inverters 1,000 feet or more from property lines if they generate more than 5 MW. The number drops to 400 feet for farms generating less power.

The rules cannot be enforced retroactively on facilities already permitted under the old requirements, which allowed inverters to be installed 100 feet from residential property lines.

More: *WHRO*