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YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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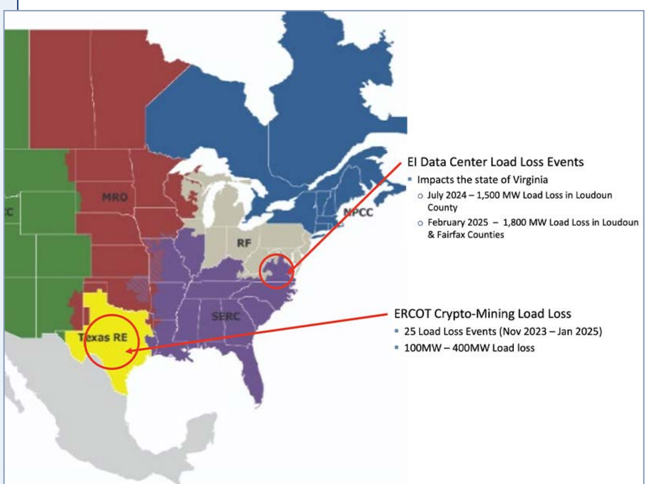
## Data Centers' Reliability Impacts Examined at FERC Meeting




*NERC*

Shoring up the grid from potential disturbances caused by data centers is going to be increasingly important, while the facilities' impact on resource adequacy will also continue to be a major issue facing the entire power industry.

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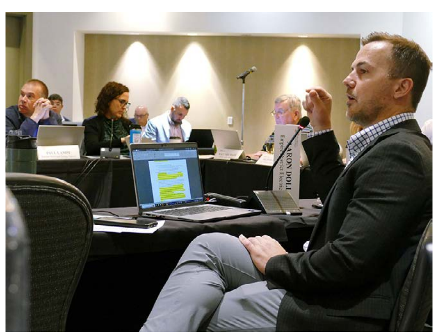

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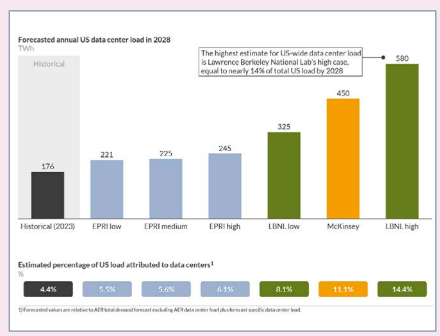


*Aurora Energy Research*

### The Promise, Uncertainty and Unparalleled Risk of Data Center Load (p.3)

Our new columnist, Peter Kelly-Detwiler, writes that the data and utility industries are being thrust together to create what eventually will be a central nervous system that will affect the entire planet. They need to do a lot more work to better understand each other, optimize their approaches and de-risk the outcomes.

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# In this week's issue

# The Promise, Uncertainty and Unparalleled Risk of Data Center Load

*By Peter Kelly-Detwiler*

Peter Kelly-Detwiler

Recent headlines and projections related to emerging data center load are astonishing. In February, Dominion Energy reported over 40 GW of data center contracts in its Virginia service territory as of December 2024, an increase of 88% from *its July number*. To put those numbers in perspective, Dominion's record peak load in 2024 was *just over 23 GW*.

Meanwhile, that same month PPL Corp. *stated* it had received 54 GW of requests across its Pennsylvania and Kentucky service areas. PPL's 2024 *peak demand* was 7 GW. Through the same period, Texas utility Oncor *highlighted* 228 transmission-level interconnection requests for 119 GW, almost four times larger than the 31 GW of demand it currently serves.

Numerous other utilities also are seeing significant numbers, with Exelon *reporting* data center load of 16 GW, and some single "hyperscaler" projects well over 1 GW. For example, Meta's $10 billion hyperscale *endeavor* with Entergy in northeastern Louisiana is sized at 2 GW.

This activity is part of a global race to expand artificial intelligence capabilities while growing the underlying data center infrastructure. The investments clearly will be enormous, with profound implications for many utilities, especially those close to communications cables (it's the confluence of numerous high-speed cables that makes Dominion's northern Virginia region the data center capital of the world). However, it has become increasingly apparent that access to existing communications infrastructure is not as important as it once was. Today's imperative is to access electricity as fast as possible, which means more utilities eventually will be affected.

## Why This Matters

The data and utility industries are being thrust together to create what eventually will be a central nervous system that will affect the entire planet. They need to do a lot more work to better understand each other, optimize their approaches and de-risk the outcomes.

### The Overriding Mandate for Power

Leading chipmaker Nvidia's CEO Jensen Huang highlighted the primacy of power in his March GTC keynote, stating:

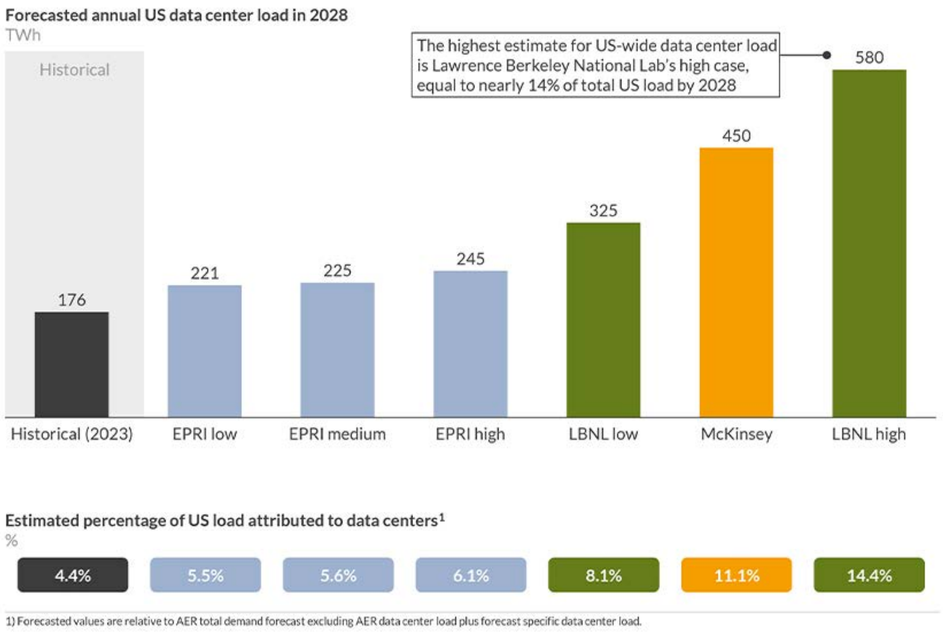
"Remember that one big idea is that every single data center in the future will be power limited. Your revenues are power limited. You could figure out what your revenues are going to be based on the power you have to work with. This is no different than many other industries. And so, we are now a power limited industry. Our revenues will associate with that."

It's all about accelerated access to the electron, so data companies are willing to go wherever electricity is available. That explains why Meta is working with Entergy to build three 750-MW gas generators in a remote and impoverished province in northeastern Louisiana. It's also why Texas is a hot spot for new data load — the state has the land, and more importantly, it's one of the easiest places in the country to develop new generating assets.

### The Risks to Utilities and Ratepayers

After decades of relatively flat — or even negative — growth, many utilities understandably like what they see: enormous, high load factor demand from some of the most well-capitalized companies on the planet. At first blush, data load looks like a perfect antidote to stagnating utility revenues. However, this value proposition brings with it a significant level of risk. To understand where that risk lies, it helps to break this issue into discrete elements:

- The Interconnection Requests and "Phantom Load" — The data industry power imperative is simple: Get access to energy as quickly as possible to maintain competitiveness. To get that power, large players may deal with utilities directly, or they may buy existing




Estimates vary widely for data center load growth, ranging between 5-14% of total U.S.-wide load by 2028 | *Aurora Energy Research* projects put together by other developers. In either case, they are incentivized to develop multiple applications across numerous locations.

- If Project A wins, they withdraw Projects B and C. This approach is similar to the supply interconnection queue, in which fewer than 20% of projects initially entering the queue ultimately flow power. The fluid nature of the industry also results in constant changes. For example, in March, Microsoft withdrew 2 GW of projects in Europe and the U.S., and then in April, it pulled back from three Ohio projects worth $1 billion.
- In addition to the big hyperscalers, numerous other players are active, including speculative developers looking to grab land, access power and flip their projects to third parties. The result is an inflation of the interconnection numbers that may be quite significant.
- Contract Lengths and Temporal Mismatches — Recent contractual structures approved by utility commissions typically include a ramp period of four to five years, followed by a period of 12 to 15 years at full load. Contracts often are structured as take-or-pay agreements, meant to inoculate ratepayers during the length of the contract period, but only for the initial contract length. The problem is the contract durations align poorly with generation and transmission infrastructure with lifespans that often exceed 30 or 40 years. If data center loads were not so large, this risk would not be as considerable. Given their magnitude, if data center load shrinks or disappears, stranded asset risk could be quite considerable.
- Competition & Consolidation — In the U.S. alone, more than a dozen entities have developed over 40 large language models that consume huge amounts of data and electricity. If the past battle for search engine supremacy or the lessons of general economic theory are anything to go by, we can expect many of these actors to fail or be consolidated in the future, creating attendant risk for both the utilities holding the supply contracts and their captive ratepayers.
- Constantly Evolving Technologies — Data center technologies are highly dynamic and are becoming increasingly efficient. In cooling, which consumes roughly 35% of data center load, liquid and two-phase cooling promise to cut energy consumption dramatically, by as much as 90%. Meanwhile, performance of the cutting-edge chips from Nvidia demonstrates remarkable gains. The next-generation chip — to be delivered by 2027 — will yield performance gains of 900 times that of its chip introduced in 2022. Supported by AI itself, future chip efficiencies will improve.
- Approaches to Training the Large Language Models — The traditional "brute force" approach to training AI models has been to combine powerful chips with huge amounts of electricity to crunch data — in some cases as much as a trillion parameters in a single training model. However, news out of China this spring suggests that in some instances there may be a better way that involves far few chips and significantly less energy. DeepSeek and Baidu's Ernie X1 reportedly focused more on algorithms and software efficiency, so that they used fewer chips and far less energy. Neither has provided solid information with regard to their metrics, so verification is difficult, but there could be far better ways to achieve AI-related outcomes.
- The biggest question related to efficiencies is simple: If the training models get less expensive, and the applications become more cost-effective, will society simply end up applying more artificial intelligence in more sectors of our economy? We thus would use less energy in our training models and more in "inference," the application of the models to the real work in reasoning and making decisions. It's simply too early to say.

## The Challenge and Opportunity, and the Need for More Rigor

All of these issues point to today's indisputable reality: The entire industry is morphing so quickly that nobody really knows what it will look like just a year or two from now. Given how rapidly the industry is growing, the hundreds of billions of dollars of investments that will take place just this year alone, and the rapid evolution of the models and underlying technologies, projecting the future is impossible. But we do know that big is big. The sheer magnitude of the potential investments required for both AI and general data center load suggests the opportunities for the utilities are unparalleled, even as the risks have rarely — if ever — been greater.

Utilities and grid operators are beginning to recognize these risks and approach some of these issues with more deliberation. In April, for example, ERCOT in its Long-Term Hourly Peak Demand and Energy Forecast highlighted 86 GW of data center load in 2031 as identified by Transmission Service Providers (TSPs). That number was based on both signed contracts and attestations from TSP executives. However, ERCOT significantly reduced its data center load forecast to 24,200 MW, "based on observation of behavior and characteristics of these loads, including average project delay, load profile by type and average project realization." That's still admittedly a very crude approach, but better than taking the numbers at face value.

PJM's Independent Market Monitor recently commented on data loads and their potential impacts on markets, transmission and reliability, suggesting the grid operator should create a formal interconnection process — including milestones — similar to the one for supply. "Every new generator and every large load addition should go through this process," the Market Monitor commented, adding, "There are no short cuts."

Utilities also need to dramatically improve their interconnection processes. They need to better understand all aspects of this rapidly expanding and evolving industry — function, purpose, key value propositions, technologies and business models — and the attendant risks and opportunities for utilities and ratepayers.

The data and utility industries come from completely different cultures, technologies and ecosystems. They now suddenly are being thrust together to create what eventually will be a central nervous system that will affect the entire planet. As such, they need to do a lot more work to better understand each other, optimize their approaches and de-risk the outcomes. ■

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

# Stop the Insanity, Trump 2.0

*By Steve Huntoon*


Steve Huntoon

Last week, I wrote about a couple of breathtakingly foolish executive orders. I ran out of breath before getting to a third executive order that is competitive in this category.

*This one* commands the U.S. Department of Energy to develop a complete methodology/model of the electric power grid within 90 days and, among other things, prohibits the retirement of any generation resource deemed critical to regional system reliability. The DOE is required to analyze current and "anticipated" reserve margins by region. (Reserve margin meaning a surplus of electric supply over electric demand.) Let's think about this.

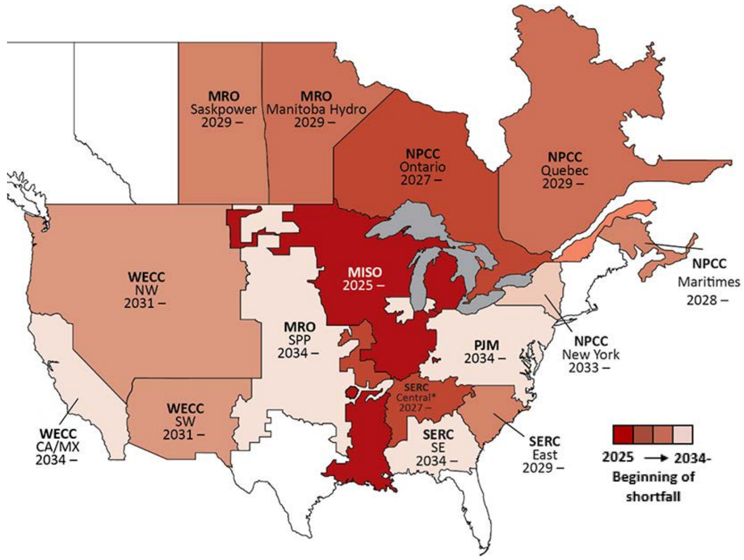
"Anticipated" electric demand will increase over time.

"Anticipated" electric supply will not increase over time because the prescribed methodology will "accredit" only generation resources that currently exist. This guarantees that anticipated reserve margins will be deemed deficient, thus mandating DOE orders under Section 202(c) of the Federal Power Act prohibiting virtually all generator retirements.

This phenomenon is illustrated by a NERC map (*Figure 2 on Page 8*) projecting that by 2034, the entire country except Texas, New England and Florida will be deficient. Again, this is caused by ignoring new generation.

Generators retire when they become uneconomic. The upshot of the executive order is to keep the uneconomic generators around, discouraging new economic generators from being built that would relieve the deficiency. So the reserve margin deficiency will never end. The perfect self-fulfilling prophecy!

If you're thinking you've seen this movie before, you're right! In Trump 1.0, the use of Section 202(c) was urged by coal magnate Robert Murray to help his coal sales by keeping uneconomic coal plants open. I wrote multiple columns discussing that insanity, such as *this one*.



Projected reserve margin shortfall areas | NERC

To his credit, DOE Assistant Secretary Bruce Walker — a Trump appointee — *said back then*: "We would never use a 202 to stave off an economic issue [emphasis added]. That's not what it's for."

I guess "never" has a short lifespan these days. DOE was, of course, right in Trump 1.0. Section 202(c) is for short-term true emergencies — not to keep uneconomic generators around. And any order is required to be "temporary," whereas these 202(c) orders would be the opposite of temporary. Did I mention the costs of subsidizing uneconomic generators, and the question of who should pay such subsidies?

Honorable mention for Trump 2.0 insanity goes to the Trump administration *ordering* that construction stop on a fully licensed wind project.

And another honorable mention goes to Trump's statement that pro bono resources extorted from law firms would be donated to the coal industry: "We're going to use some of those firms to work with you on your leasing and your other things."

Peabody Energy had not occurred to me as a worthy pro bono recipient, but what do I know?

What I do know is that the upshot of what I covered here and in the prior column is to create unprecedented uncertainty for the electric industry. Stability, transparency and the rule of law have been America's biggest competitive advantages for our industry and all others. Now we lose those.

Rational investments can't be made when:

- Fundamental elements of a regulatory construct may disappear next year, in five years or maybe never.
- Nobody knows who's really in charge of what.
- Uneconomic generation may be kept around and subsidized indefinitely.
- Past decisions might change on a whim and all decisions might be reversed on judicial review.
- Previously granted licenses/permits are effectively revoked on a whim.
- Resources are extorted from one industry to subsidize a favored segment of another industry.

The collapse of economic investment in our industry doesn't have winners and losers. Only losers. If you have a say in regulatory and legal policies for our industry, please don't be shy.

P.S. If you might indulge me an update about Kilmar Armando Abrego Garcia, the 4th U.S. Circuit Court of Appeals has said in an *order* authored by Judge J. Harvie Wilkinson, a conservative Reagan appointee: "The government is asserting a right to stash away residents of this country in foreign prisons without the semblance of due process that is the foundation of our constitutional order."

Huzzah! ■

*— Columnist Steve Huntoon, a former president of the Energy Bar Association, practiced energy law for more than 30 years.*

# Data Centers' Reliability Impacts Examined at FERC Meeting

By James Downing

Sudden trips offline by data centers in Virginia and cryptominers in ERCOT present new reliability challenges that must be managed, NERC Chief Engineer Mark Lauby told FERC at its monthly open meeting April 17.

The grid in Loudoun County, Va., home to the largest concentration of data centers in the world, was experiencing some voltage sensitivities last summer, Lauby testified.

"In July 2024 we saw about a 1,500-MW drop as a result of some system conditions — in this case, switching after a fault on the system," Lauby said. "And within 50 seconds, three of those voltage excursions occurred, and the load is monitoring that, and when it sees that happen, it comes offline because it wants to protect its cooling load."

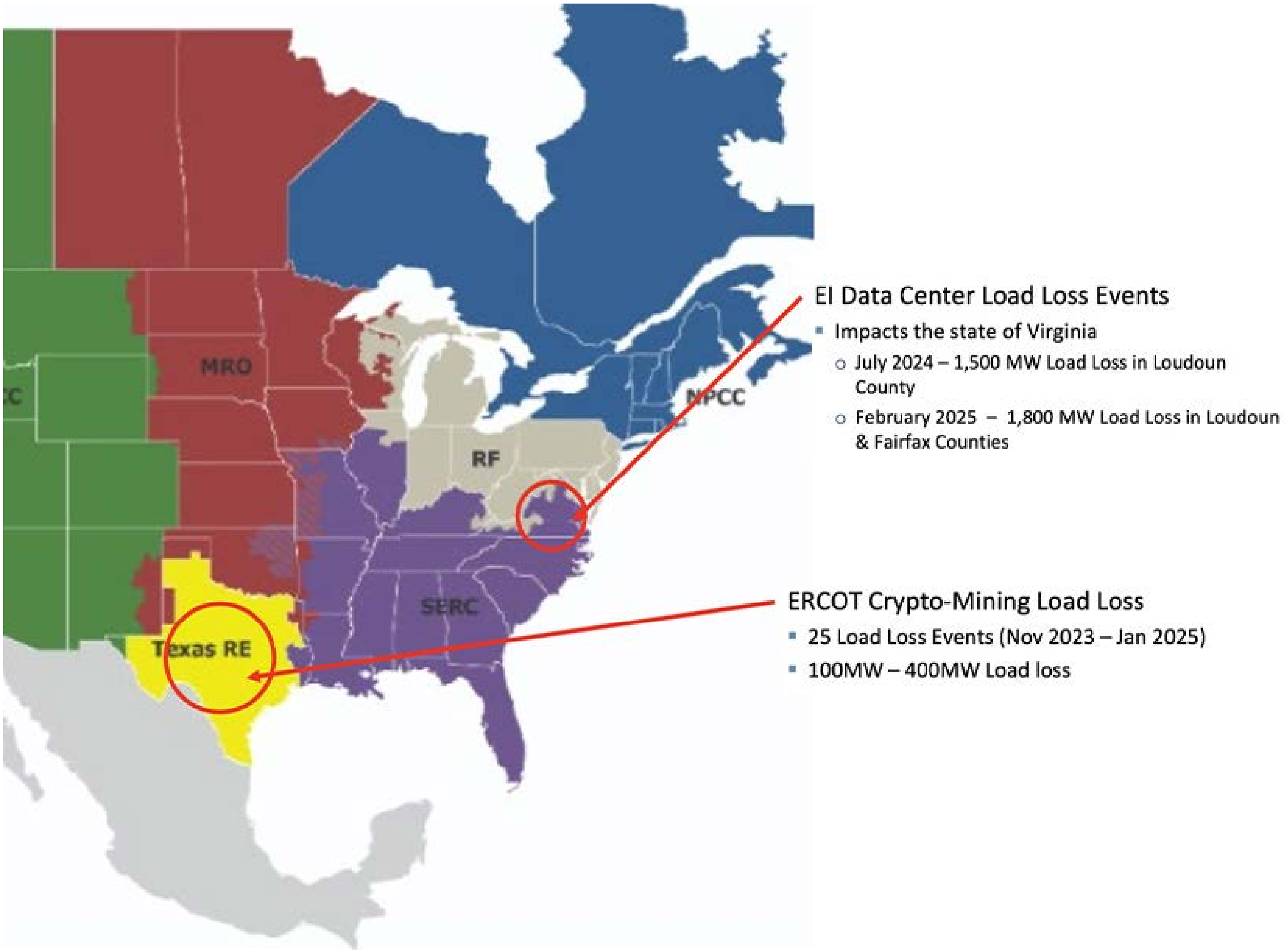
## Why This Matters

Shoring up the grid from potential disturbances caused by data centers is going to be increasingly important, while the facilities' impact on resource adequacy will also continue to be a major issue facing the entire power industry.

NERC released a *report* on the incident in January that details the grid conditions before and after the data center load went offline. (See *NERC Report Highlights Data Center Load Loss Issues*.)

A similar event happened in Loudoun and neighboring Fairfax County, where 1,800 MW of load suddenly dropped off the system. Lauby said while that is still being investigated, he suspects it will be similar to the July 2024 incident.

Texas has seen more frequent but smaller events as grid conditions have caused cryptocurrency mining facilities to trip offline 25 times between November 2023 and this January, leading to 100 to 400




A slide from NERC Chief Engineer Mark Lauby's presentation to FERC detailing recent reliability incidents caused by data centers tripping offline. | *NERC*

MW of losses in each incident.

"Historically, if we lose generators, it can trip off the grid," FERC Chair Mark Christie said during the meeting. "Now we've got another issue, which is if large load users simultaneously go off together, it affects the frequency and potentially trips off the whole system."

The grid can be engineered to avoid those cascading outages across multiple data centers to avoid a situation where the grid's largest single contingency comes from demand (as opposed to a large power plant or transmission line), Lauby said.

"That comes down to engineering, modeling and continuing to work with the industry — in this case, the large load industry and the power industry — to see how we manage that interconnection," he added.

NERC is considering rule changes to deal with the newfound risk, which is going to be exacerbated as individual data centers' load grows to the size of major cities. The grid has dealt with large industrial facilities at 100 to 200 MW for decades, but some of the proposals for large data centers run to thousands of megawatts, which compares to the total loads of San Francisco or D.C. in a single place, Lauby told FERC.

"We need to, obviously, make sure that's managed well, and the engineering is done to ensure that we minimize the chances for things to happen," he added.

NERC stood up a Large Loads Task Force in 2024 that is expected to issue papers and guidelines to address the risks associated with the issue. The ERO is also working on industry guidance on large loads, incorporating work from the task force.

Part of that analysis is to determine how to register the loads, either by requiring the customers themselves to register with NERC, or if that is not legally feasible, then getting their load-serving entities to do it for them, Lauby said. Then once the facilities are registered, NERC will craft reliability standards so that the chances of such incidents are minimized.

"Large numbers actually really scare me; the potential reliability impact of these drops sound pretty severe," Commissioner Judy Chang said.

Modeling can help NERC secure the grid against uncontrollable outages of data centers; Chang asked what kind of data are needed to effectuate that.

Losing 1,500 MW of load is akin to one and a half large nuclear units tripping offline, but the grid has reserves that can maintain reliability in such cases, Lauby replied. NERC has the authority to get data from the industry under the Federal Power Act.

"For the loads, they've just been good enough to work with us," Lauby said. "And, so, is that going to be good for the long term? Probably not … [it's] something we need to think about."

Large loads tripping offline is one part of the reliability equation when it comes to data centers, with the other key part being meeting their demand with an adequate supply of resources, Lauby said.

"The definition of reliability is adequacy and operation reliability," he said. "So, we've got both problems." ■

# EIA Projects Demise of Coal, Rise of Renewables

## Annual Report Reflects Biden Policies; Data Predate Trump's Sweeping Revisions

*By John Cropley*

The U.S. Energy Information Administration predicts sharp increases in renewable power generation and sharp decreases in coal-fired power in its 2025 *Annual Energy Outlook*, released April 15.

The EIA also projects an overall decrease in U.S. energy consumption over the next decade, with subsequent increases so small that 2050 levels still are lower than 2024 levels.

The agency notes that the numbers vary among the modeling scenarios used, and it makes clear the projections were created using the laws and regulations in place in December 2024 — a month before a president who supported energy conservation was replaced by one moving to increase energy production and consumption.

The EIA and its parent agency, the Department of Energy, now work for President Donald Trump. The April 15 release of the AEO was accompanied by a DOE spokesperson's attack on President Joe Biden's policies and affirmation of Trump's policies.

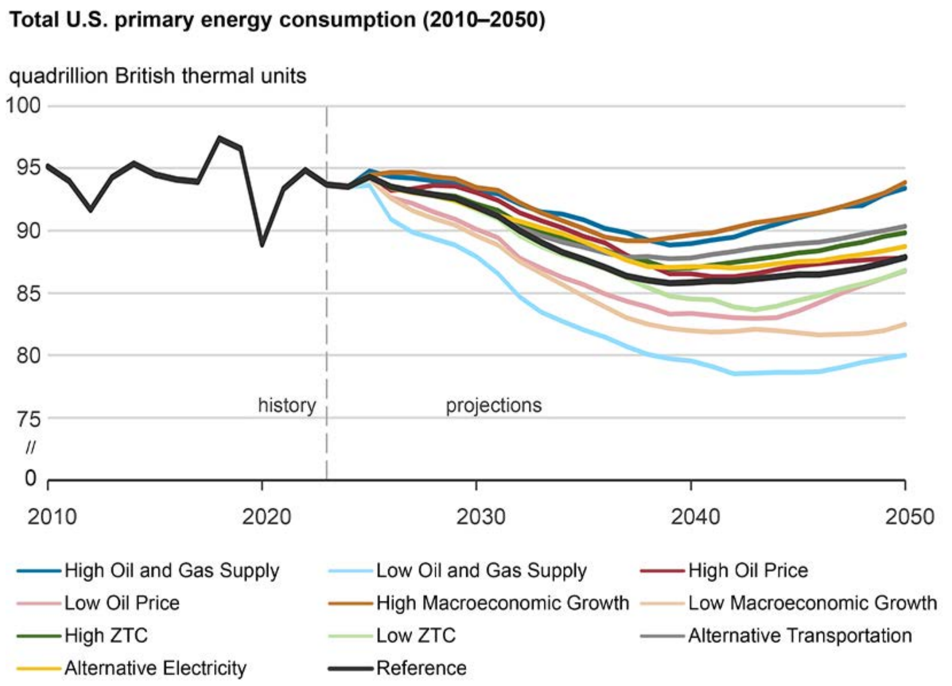
Some of the projections in the outlook — such as a drop in nuclear generation capacity — seem to run counter to recently stated priorities. Others, such as the rise of renewables and demise of coal, reflect Biden policies that Trump is trying to reverse.

*Changes in annual metrics* projected from 2024 to 2050 include:

- Net electricity available to the grid will jump from 4,139 billion kilowatt-hours (BkWh) to 6,045 BkWh.
- Natural gas generation will drop from 1,901 BkWh to 1,270.
- Nuclear generation will drop from 777 BkWh to 736.
- Coal generation will drop from 660 BkWh to 7, with the biggest decrease — 402 BkWh to 52 — coming from 2029 to 2032.
- Renewables will jump from 1,060 BkWh to 4,680.
- Average end use electricity prices (in 2024 dollars) across all sectors will drop from 13 cents/kWh to 12.1 cents.
- Electricity purchased for vehicle charging will jump from 0.06 quadrillion British thermal units (quads) to 2.68 quads, with residential users accounting for 59% of the total and commercial 41%.
- Heating degree days will decrease 5.4% nationwide per year, and cooling degree days will increase 15.7%.
- Energy consumption intensity will drop from 91,300 BTU/square foot to 84,900 in commercial settings and from 52,300 to 40,800 in residential settings.
- Annual generation by major renewables will jump from 0.4 BkWh to 174 BkWh for offshore wind, 16 to 56 for geothermal, 201 to 1,791 for grid-connected solar, 242 to 273 for hydroelectric and 446 to 1,908 for onshore wind.

### Why This Matters

The report's projections are overshadowed by subsequent Trump administration policy changes.




Future energy use in the U.S., as projected by the Energy Information Administration based on factors present in December 2024. | *EIA*

While the U.S. produced more crude oil and natural gas per year than any other country ever during the Biden administration, Biden also led policy changes that promoted renewables over fossil fuels.

Trump railed against this during his campaign and initiated a sharp change of course on the first day of his second term. His administration continued this narrative as it commented on the AEO.

DOE spokesperson Andrea Woods said the report reflects Biden's short-sighted energy policies and the disastrous path they set for the countries. It does not, she said, reflect the policies enacted by Trump.

The department, she said, is working now to advance coal, natural gas and nuclear energy to promote affordable, reliable and secure energy and build U.S. energy dominance. ■

# SunZia Gets Mixed Decision on Tariff

## Pattern Energy Seeking to Include Southwest Transmission Line in CAISO

*By Elaine Goodman*

FERC on April 17 approved the non-rate terms of SunZia Transmission's proposed transmission owner tariff but sent the tariff's non-subscriber usage rate to a settlement process and potential hearing (*ER25-170*).

Pattern Energy is developing the SunZia transmission line, a 552-mile, 500-kV DC line that will carry wind power from New Mexico into Arizona. The SunZia line, with a planned capacity of 3,021 MW, is expected to begin operations in 2026.

SunZia plans to join CAISO's balancing authority area as a subscriber participating transmission owner (PTO). The subscriber PTO model allows transmission developers to join CAISO without the transmission project being selected through CAISO's transmission planning process.

Developers of subscriber PTO projects are responsible for funding the transmission project, rather than recovering their transmission revenue requirement through CAISO's transmission access charge (TAC). FERC approved the subscriber PTO model in March 2024. (See *CAISO Wins FERC Approval for Subscriber-funded Tx Plan*.)

In the case of SunZia, the transmission system's existing capacity has been committed to Pattern subsidiary SunZia Wind, which has entitlements with Salt River Project, Western Area Power Administration and Tucson Electric Power to send its wind power beyond SunZia Transmission's Pinal Central terminus to Palo Verde, which connects with the CAISO system.

In the subscriber PTO model, transmission capacity not used by subscribers is available to CAISO market participants. CAISO will pay the subscriber PTO for that usage based on a non-subscriber usage rate (NSUR).

The NSUR in SunZia's proposed tariff drew protests from a group of utilities — Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric — as well as from a group of six California cities.

One complaint about SunZia's proposed NSUR was that it was developed using the Appalachian methodology, which came from a 1987 FERC case involving Appalachian Power Co. As described by FERC, the methodology is "premised on the assumption that a customer using the transmission system for the 16 peak hours of the day should pay the same contribution to fixed costs as a customer who has reserved capacity on a daily basis."

### Why This Matters

The SunZia line will play a key role in helping California meet its targets for tapping wind generation in New Mexico.

The protesters also said SunZia hadn't provided support for an annual escalation factor of 0.5%.

While FERC found the escalation factor to be just and reasonable, it shared the protesters' concerns about use of the Appalachian methodology in calculating the NSUR.

Under FERC's order, the chief judge will appoint a settlement judge within 45 days and a settlement conference will be held to try to resolve the NSUR matter. If a settlement can't be reached, the issue will go to an evidentiary hearing.


Map shows the locations of the SunZia wind and transmission projects. | *Pattern Energy*

### Expedited Action Requested

SunZia initially filed the proposed transmission owner tariff Oct. 21, 2024, and a month later asked for a decision by Dec. 21.

Citing its obligation to investors, lenders and customers, SunZia Transmission filed a renewed request for expedited treatment March 14, asking FERC to issue an order by April 30.

"If the commission does not provide expedited action, SunZia Transmission will be forced to divert its resources to an alternative plan that would require it to form its own balancing authority area ("BAA") rather than joining CAISO's BAA," SunZia said in the filing.

Forming its own BAA would take several months and require "a significant commitment of resources" from SunZia, NERC and WECC, the filing said. ■

# Western Utilities Prep for Wildfire Season with New Initiatives, Tech

## Utilities Give Their Assessments Ahead of 2025 Fire Season

*By Henrik Nilsson*

As the months get warmer, utilities in the West are gearing up for another wildfire season, equipped with new technology and lessons learned from recent fires in Los Angeles they hope can assist in mitigation work.

"The January 2025 windstorm and fires have driven SCE to further mature and evolve its wildfire mitigation efforts," Southern California Edison spokesperson Jeff Monford told *RTO Insider* on April 15. "Based on these experiences, we have developed a forward-looking strategy that addresses both immediate and long-term wildfire risks."

The L.A. wildfires erupted Jan. 7 following a windstorm. The fires collectively destroyed thousands of homes and businesses in the Altadena, Malibu and Pacific Palisades communities, killing more than 20 people, according to Cal Fire. (See *No Grid Impact from LA Fires, CAISO Says*.)

SCE has stated its equipment may have been involved in the cause of the Eaton Fire, which burned more than 14,000 acres and engulfed parts of the Altadena community.

On April 11, SCE announced plans to underground more than 150 miles of transmission lines in Altadena and Malibu after the fires. The cost of the rebuild is estimated at $860 million to $925 million, *according to a news release*.

The effort comes after California Gov. Gavin Newsom suspended environmental laws to accelerate the undergrounding and hardening of utility equipment in communities ravaged by the Los Angeles wildfires. (See *Newsom Issues Order to Speed Undergrounding of Lines in Los Angeles*.)

SCE has already allocated $5.4 billion to implement its 2023/25 Wildfire Mitigation Plan. Additionally, between 2018 and 2024, the utility installed more than 200 cameras with artificial intelligence capabilities, over 1,700 weather stations and approximately 6,400 circuit miles of covered conductor, while carrying out "more than two million tree trimmings and removals," according to Monford.

### Why This Matters

As the months get warmer, initiatives launched by utilities aimed toward mitigating the impacts of wildfires will get their first real test.

SCE will share its 2026/28 Wildfire Mitigation Plan in May, Monford added.

On March 24, Cal Fire completed an update to its fire hazard severity zone map for the first time since 2011. The *updated map* shows large swaths of Southern California falling under "very high fire hazard" zones.

Other utilities *RTO Insider* spoke with have ramped up their wildfire mitigation work in the face of increased risks.

For example, San Diego Gas & Electric launched its Wildfire and Climate Resilience Center in the fall of 2024.

"The center is essentially a focal point of SDG&E's climate resilience strategy," Alex Welling, communications manager at SDG&E, told *RTO Insider* in March, before Cal Fire issued the updated maps.

The center is a hub for research, development and implementation of wildfire mitigation tools built on AI and predictive modeling and information sharing with emergency responders, Welling explained.

SDG&E also uses data from the California Public Utilities Commission's High Fire Threat District maps to power its modeling software. The software "helps prioritize wildfire mitigation projects by considering both wildfire risk and public safety power shutoff risk to determine the likelihood of either a wildfire or PSPS taking place, its subsequent impacts and then recommends proactive mitigation measures" Welling said.

### Pacific Northwest

Information sharing has become increasingly important in the wake of the L.A. fires, Ryan Murphy, director of electric operations at Puget Sound Energy (PSE), told *RTO Insider*.

"Wildfire has changed the risk paradigm for utilities," Murphy said. "We used to be a relatively low-risk industry. That is no longer the case — we now have become extremely high risk because of wildfire."

Because of changing weather conditions, PSE has stepped up its wildfire mitigation work and expanded its Wildfire Mitigation and Response Program, Murphy said.

For example, the utility uses AI to improve fuel models, consults with a third-party fire science expert and uses weather stations, cameras and insights from field crews to get a "much more granular and local level where to focus grid hardening and vegetation management work," Murphy said.

"We have also added a meteorologist in the last year, giving us much greater visibility into the varied weather conditions across our service area and how those might impact operations," he added.

Still, with recent trends of longer, hotter and drier summers, the wildfire threat in 2025 "has the potential to be very high," Murphy said.

"If timely rains arrive across the region throughout spring, it will help delay the start of peak wildfire risk into late June or July, thereby shortening the overall risk duration," according to Murphy. "However, if spring plays out to the warmer and drier side across Washington, the potential for earlier and active wildfire threat should be expected."

In Oregon, investor-owned utilities must by June file wildfire mitigation plans for approval by the Oregon Public Utilities Commission. Utilities presented their plans in February.

Portland General Electric, Idaho Power and PacifiCorp, all of which serve customers in Oregon, have started under-

Shutterstock

grounding lines, building out networks of wildfire cameras and installing weather stations to gather wind speed data, among other efforts, according to their February presentations. (See *Oregon Utilities Enter 2025 With Ambitious Wildfire Plans*.)

There were 64,897 reported wildfires in 2024 that burned approximately 8.9 million acres nationwide, compared to 2.7 million acres in 2023. Oregon saw nearly 1.8 million acres burned due to wildfires, according to the National Interagency Coordination Center.

Oregon PUC spokesperson Kandi Young told *RTO Insider* in an email that this year, "Oregon utilities are improving their outreach and communication to customers as the more extensive use of sensitive or enhanced safety settings reduces the risk of ignitions but also degrades the reliability experienced by customers with less advance warning than a [PSPS]."

"Communities are seeking more clarity about why outages occur and how long an outage is likely to last, whether due to these settings, a PSPS, or due to approaching wildfires and the need for turning off the power so fire suppression resources can operate," Young added.

The PUC is also paying attention to the fire events in L.A., Young said.

"We continue to see extreme fire behavior and urban conflagrations under high wind conditions, regardless of the source of the ignition," Young said. "Power is often turned off during these conditions, complicating the response. Public safety partners, entities that provide critical services such as communications, and community members need to be preparing for wildfire, even if they are not in a designated high fire risk zone."

## Federal Workforce Reductions

Layoffs among federal agencies initiated under the Trump administration have caused uncertainty within the power industry. The layoffs have also reached agencies like the National Oceanic and Atmospheric Administration that monitor wildfire activity and produce seasonal outlooks. (See *BPA to Restore 89 'Probationary' Staff, Agency Confirms*.)

Young said workforce reductions among agencies "raise concerns about both off-season mitigation activities and fire-season readiness. We expect the utilities to incorporate any reduced federal prediction and response capabilities in their seasonal and operational risk assessments."

Murphy with PSE said the utility monitors changes within the federal workforce and recognizes "the situation remains fluid. We consult with a number of agencies and third-party vendors for modeling in addition to federal agencies."

SDG&E is less concerned, Welling said.

The utility's monitoring systems, weather forecasting models and cameras "ensure we maintain the highest level of situational awareness," according to Welling. "These capabilities allow us to independently monitor and predict wildfire behavior, ensuring our operations remain efficient and effective." ■

# CAISO Issues 'Expedited' Plan for Allocating EDAM Congestion Revenues

## Proposal Seeks to Strike Balance Between Existing Rules, Issue Paper Alternative

*By Robert Mullin*

CAISO on April 17 released a draft final proposal detailing how its Extended Day-Ahead Market (EDAM) will allocate congestion revenues in circumstances when a transmission constraint in one balancing authority area produces "parallel" flows — with resulting transmission congestion — in a neighboring BAA also participating in the market.

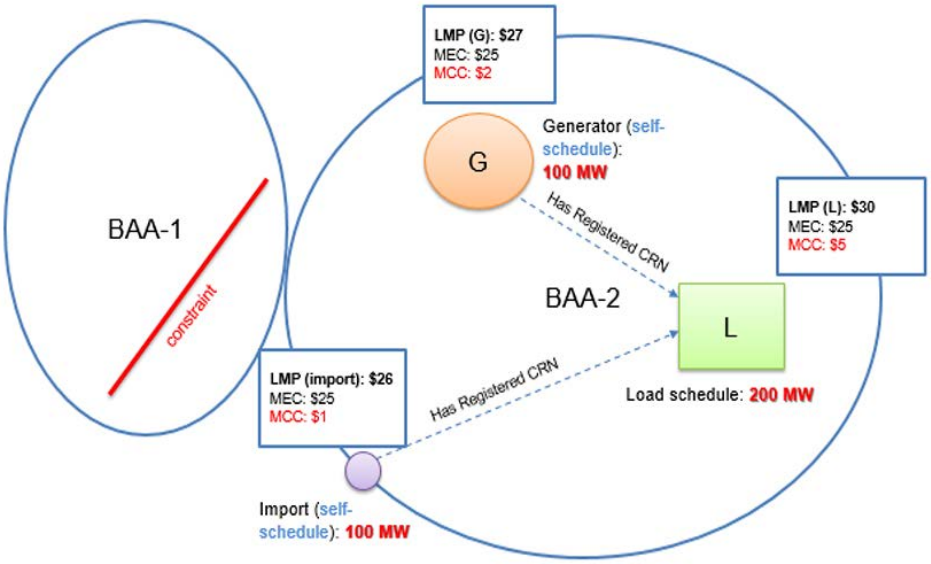
The *draft proposal* is the product of an "expedited" stakeholder process the ISO kicked off in March to address concerns among some Western electricity market participants that EDAM would leave some non-CAISO participants exposed to congestion charges for constraints occurring outside their systems, while not providing them the ability to adequately recover or hedge against the charges. (See *Fast-paced Effort will Address EDAM Congestion Revenue Issue*.)

"This proposal for parallel flow congestion revenue allocation is an initial step toward continued evolution of the overall congestion revenue allocation design informed by market operational experience and stakeholder input," CAISO said in the proposal.

Vancouver, Canada-based electricity trader Powerex first called attention to the issue in a February paper contending that EDAM's handling of congestion revenues represented a "design flaw," which the company identified after reviewing PacifiCorp's proposed revisions to its open access transmission tariff intended to accommodate its participation in the market, scheduled to begin in 2026. (See *Powerex Paper Sparks Dispute over EDAM 'Design Flaw'*.)

### Why This Matters

CAISO is moving quickly to get approval for new rules for how EDAM will allocate congestion revenues as more utilities move to revise their transmission tariffs to reflect their participation in the market.




Example of exercise of firm OATT transmission rights through balanced source and sink self-schedules with LMPs. | *CAISO*

Powerex is a firm OATT rights holder in PacifiCorp's system, and it argued that any such transmission customer stands to lose value in its contracts under the arrangement.

### Seeking Balance

CAISO said its draft proposal seeks to strike a balance between EDAM's existing FERC-approved rules related to congestion revenues and the alternative scheme it floated in the *issue paper* kicking off its expedited stakeholder initiative.

Under EDAM's existing rules, congestion revenues are allocated to the BAA containing a constraint, with the operator of that BAA allowed to sub-allocate any revenue it receives from the ISO to transmission customers according to the procedure outlined in that BAA's OATT.

"This congestion allocation method recognizes that the balancing area where the internal transmission constraint is located bears the effects of that congestion and the reliability impacts associated with the constraint, and thus congestion revenues accruing across the interconnected EDAM footprint associated are allocated fully to the EDAM balancing area where the constraint is located," CAISO notes in its proposal.

The ISO said many stakeholders "saw merit" in the existing design but "also recognized the concerns expressed with parallel flow congestion revenue allocation" and the need to develop a new "transitional" approach for allocating revenues "to support the ability to more readily protect or manage congestion cost exposure for OATT transmission rights holders."

But stakeholders also expressed concerns about the potential alternative outlined in the issue paper, which proposed to allocate congestion revenues only to the BAA in which the revenues accrued, not to the neighboring area where the constraint was located. Some commenters thought the alternative went too far in reallocating the revenues, while others worried the approach could increase incentives for some transmission users to self-schedule generation to gain a more complete hedge, which would reduce the efficiency of market operations.

CAISO said its proposed design instead "leverages elements of the transitional alternative introduced in the issue paper and retains aspects of the current, FERC-approved, design to congestion revenue allocation; i.e., it is incremental to the underlying congestion revenue allocation methodology."

Under the draft final proposal, parallel flow congestion revenues collected in an EDAM BAA that result from a binding constraint in a neighboring area will first be allocated to the BAA in which the overflow congestion occurs — and the revenues are collected. That will enable that BAA to distribute funds to firm OATT transmission rights holders who possess long-term and monthly point-to-point (PTP) and network integration transmission service (NITS) rights and have submitted "day-ahead balanced source/sink schedules."

"Consistent with the existing EDAM design, transmission customers will register their firm PTP and NITS transmission rights, with the market operator identifying the nature of the rights from source to sink. These registered transmission rights will be associated with a contract reference number, which, when included in the bid submission, associates that bid with existing OATT transmission rights," the proposal states.

The plan also stipulates that any remaining congestion revenues associated with the parallel flows would be allocated to the EDAM BAA in which the constraint occurred.

"This aspect of the design mitigates the concerns expressed by stakeholders that, under the transitional alternative described in the issue paper, balancing areas may be exposed to congestion costs (negative congestion revenues) associated with parallel flow effects when generation in the balancing area provides counter flow benefit to the direction of the transmission constraint located in a neighboring balancing area," according to the proposal.

Additionally, EDAM would continue to allocate any congestion revenues that accrue within the BAA containing the constraint to that BAA, "consistent with the FERC-approved EDAM framework."

Acknowledging "the complexity of the overall topic of congestion revenue accrual and allocation," the proposal provides multiple illustrated examples of how the plan would work in practice.

### 'Guns Blazing'

CAISO is moving quickly to wrap up the congestion revenue allocation proposal in time for a vote next month by its Board of Governors and the Western Energy Markets (WEM) Governing Body.

WEM stakeholders appear to be largely on board with the ISO's sense of urgency.

During an April 9 meeting of the WEM Regional Issues Forum (RIF) in Portland, Ore., representatives from most RIF sectors cited congestion revenue allocation as CAISO's top priority right now, at the forefront of other issues the ISO will need to address to ensure a smooth launch of EDAM in 2026.

"We support moving quickly in the congestion revenue allocation initiative," Vijay Singh, senior organized markets analyst at PacifiCorp, said on behalf of the RIF's EDAM sector. PacifiCorp will be the first utility to begin participating in the EDAM next spring.

"We were really ready to come in guns blazing and go after the ISO for not doing more on congestion, but we really got to commend the ISO for kicking off the process and looking to go to the Board of Governors by May," Avangrid's Scott Olson said for the Independent Power Producers and Marketers sector.

The Bonneville Power Administration's Allie Mace, RIF liaison for the Power Marketing Administration sector, also commended CAISO for moving on the issue, but she noted the "transitional" nature of the proposed solution and encouraged the ISO to include an initiative for longer-term solutions in its policy initiative road map.

CAISO will hold a stakeholder meeting to discuss the draft final proposal April 23. ■

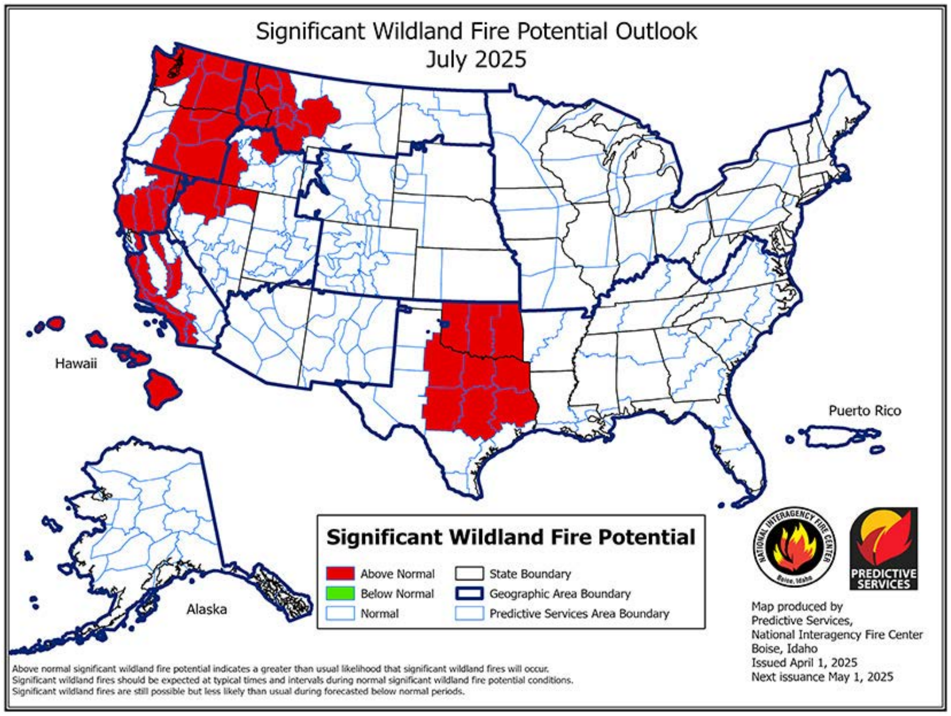
# Northwest Faces Increased Fire Risk in July, BPA Says

## Agency Looks to Build on Existing Mitigation Efforts

*By Henrik Nilsson*

The Northwest faces "above-normal, significant wildland fire potential" in July 2025, and the Bonneville Power Administration is taking steps to enhance mitigation efforts like public safety power shutoffs (PSPS) and improving communication.

Citing a seasonal outlook by the National Interagency Fire Center, Kelly Miller, supervisory land surveyor at BPA, said the region is "looking pretty good until … July."




| *National Interagency Fire Center*

"In July, the significant wildland fire potential increases quickly, and we're doing our best to prepare prior to that," Miller said during an April 17 public update on BPA's wildfire mitigation and PSPS processes.

BPA is working on updates to the fourth iteration of its wildfire mitigation plan, slated for release in May 2026. However, the agency has continuously improved mitigation processes through lessons learned since the release of the first BPA wildfire plan in 2021, Miller said.

The burn area in BPA's service territory equaled 40.8% of the national burn area. More than 3.2 million acres burned by the end of FY24, an almost three-fold increase over the 10-year average, BPA stated in its 2024 annual report. (See *BPA Hit FY24 Reliability Targets Despite Wildfires, Load Records*.)

BPA has identified several areas for improvement following extensive tests and training exercises, according to Miller.

"We don't always have ample advanced warning about impending weather," Miller said. "Sometimes weather comes on very quickly, as you can imagine, and we have to make some very quick decisions. We also realize that there are many downstream load effects on the energy system that are hard to quantify, and we are working with our distribution customers to have a better understanding of that."

"Communication is a big piece of our public safety power shutoff events, and so we continue to make improvements to that, again, both internally and externally, how we can have more awareness for our customers," Miller added.

BPA's Bonneville Dam | *Bonneville Power Administration*

BPA issued PSPS four times in 2024, which led to five line de-energizations, according to the presentation.

BPA closely collaborates with other agencies in its wildfire mitigation work. For example, the U.S. Department of Energy's Pacific Northwest National Laboratory provides wildfire modeling to BPA. BPA also coordinates wildfire efforts with the U.S. Forest Service, among others.

The agency also has explored different technological solutions, like weather sensors and smoke detection cameras "to see how we might be able to improve in the future," Miller said.

BPA follows industry standards and has created its own design and construction standards specific to its transmission assets, according to Miller. One notable standard implemented in 2024 includes placing fire-resistant wraps around transmission poles and installing more non-wood poles.

Miller noted the new standards helped save multiple poles during a fire near Keller, Wash., in July 2024. ■

# CAISO Pauses Study of New Market Run Proposal for Gas Resources

## Supporters of the Proposal Say a New 'Day+1.5' Run Could Improve System Reliability

*By David Krause*

CAISO on April 16 sidelined a proposal to provide an additional market run for gas resources due to a lack of information on the subject and a need for operational experience with the ISO's Extended Day-Ahead Market (EDAM).

The proposed new market run, known as D+1.5, would occur between CAISO's two-day-ahead market run, D+2, and day-ahead market run. D+1.5 would provide a better estimate of next-day markets as a potential to reduce reliability concerns, said NV Energy, a stakeholder in CAISO's Gas Resource Management Working Group.

Currently, CAISO uses two two-day-ahead market processes: D+2 and the residual unit commitment (RUC) look-ahead advisory. Stakeholders raised concerns about the RUC's timing and forecasting accuracy and said there is a general "lack of confidence" using such information to inform fuel procurement decisions, per CAISO's latest *issue paper* on the subject, published in January.

D+1.5 could provide new information to participants that was not available in time for the D+2 but becomes available and accessible to CAISO. For example, scheduling coordinators could submit new or updated bids, informed by the next-day gas day trading activity, into the day-ahead market to inform the D+1.5, the paper says.

### Why This Matters

Supporters of the 'Day+1.5' market run for gas resources say the proposal could improve system reliability by providing greater insight into next-day needs.

Russell City Energy Center in Hayward, Calif. | *Shutterstock*

However, to provide a D+1.5 market run, CAISO would need to establish a new process to collect gas trading data and run new forecasts. If not, D+1.5 would use the same forecasting information already used by the market processes on the trade day. Adding new forecasting services would increase vendor and personnel costs to monitor and maintain the new forecasting suite, the paper says.

The "highest-priority scope item" for CAISO's Gas Resource Management Working Group is to provide more market information to participants prior to the day-ahead market to support fuel procurement, the paper says. But the value of a new market run "must be weighed against the cost of gathering new information, running the optimization and validating a new stream of market results made available to market participants," the paper says.

"While we support the continued consideration of this new market run, we think it should be after we complete an assessment of D+2 and have some operational experience with EDAM and the new D+2 market run," Sylvie Spewak, CAISO senior policy developer, said at the April 16 working group meeting. "At this time, we don't intend on including the D+1.5 proposal in this upcoming straw proposal in detail. Let us know if you disagree with this approach." ■

# PG&E Wildfire Plan Relies on Proven Strategies, Newer Tech

## Utility Says Efforts Have Prevented Ignitions in Recent Years

*By Elaine Goodman*

A new three-year wildfire mitigation plan from Pacific Gas and Electric incorporates tried-and-true strategies such as undergrounding power lines, as well as some newer approaches, such as pole-mounted sensors.

PG&E filed its 2026/28 Wildfire Mitigation Plan with the California Office of Energy Infrastructure Safety in April.

The *plan* takes aim at each step in a "chain reaction" that can lead to a catastrophic wildfire, PG&E said. An equipment failure creates a spark that ignites flammable material, followed by flames that can spread quickly over a wide area.

"Our Wildfire Mitigation Plan employs multiple layers of protection we're using to stop catastrophic wildfires in our hometowns," PG&E Chief Operating Officer Sumeet Singh said in a statement.

PG&E equipment has been blamed for several large California wildfires, including the deadly Camp Fire of 2018, the 2020 Zogg fire and the 2021 Dixie Fire.

But PG&E said its wildfire mitigation efforts have been paying off: No major wildfires were sparked by the company's equipment in 2023 and 2024.

### Why This Matters

With its troublesome record of wildfire ignitions, PG&E's fire prevention plans are likely to be scrutinized closely by state officials and residents.

### Ignition Prevention

PG&E's priority is preventing ignitions in areas at high risk for wildfires, the company said in its plan.

That means using operational measures such as public safety power shutoffs when fire danger is high. A PSPS is "a last-resort tool to prevent fires during extreme weather," PG&E said in a release.

Another tool is enhanced powerline safety settings (EPSS), which shut down power in a split second if a problem is detected, such as a tree branch falling onto a line. EPSS reduced CPUC-reportable ignitions by 72% in 2024 compared with 2018-2020 averages, the company reported.

Because PSPS and EPSS create reliability issues for customers, PG&E said it's working to minimize the impacts of their use. The average duration of outages on an EPSS-enabled circuit fell 17% in 2024 compared to the prior two-year average.

Another step to reduce ignition risk is undergrounding of power lines. PG&E plans to bury an additional 1,077 miles of lines during the plan period.

The plan also includes overhead system upgrades, such as installing covered conductor, strengthening poles and using wider crossarms. PG&E plans overhead upgrades across 190 circuit miles each year of the plan, for a total of 570 miles.

"Our key resilience mitigations — undergrounding and system hardening — will continue at a steady pace to provide more permanent risk reduction," the company said in its plan.

PG&E also plans to expand its remote grid program, in which the company removes overhead power lines and implements standalone energy systems for small clusters of homes and businesses at the end of long distribution lines that run through fire-prone areas. Eleven remote grids were in operation in 2024, and 20 more were under development. (See *PG&E Building 'Remote Grids' in Fire-prone Areas*.)

### Pole-mounted Sensors

In July 2024, when California was in a record-setting heat wave, a Gridscope sensor mounted on one of PG&E's power poles alerted the company that something was wrong.

A troubleshooter traveled to the location and found vegetation smoldering on an energized line, according to PG&E, which now is eyeing a wider Gridscope deployment as part of its three-year plan.

Gridscope sensors can detect vibrations, sounds and light and problems that could start a fire. PG&E started testing the Gridscope in 2023, expanding to more than 10,000 sensors across 900 circuit miles last year.

PG&E also is looking at expanding its use of Early Fault Detection, a pole-mounted radio frequency monitoring technology. The sensors may find hard-to-detect issues such as damaged conductor strands or invasive vegetation.

Electrical corporations in California such as PG&E are required to prepare and submit Wildfire Mitigation Plans (WMPs) to the Office of Energy Infrastructure Safety. The office, also known as Energy Safety, was established through state legislation following devastating wildfires in 2017 and 2018. Energy Safety reviews and approves the submitted plans. (See *Calif. Agency Seeks to Transform Wildfire Safety Culture* and *Western Commissioners Ramp up Wildfire Efforts*.) ■

# APS, PNM Closer to Order 2023 Compliance

## FERC Finds Flaws in Filings from Both Southwestern Utilities

*By Elaine Goodman*

Two Southwestern utilities — Arizona Public Service (APS) and Public Service Company of New Mexico (PNM) — are closer to compliance with FERC Order 2023 but still have work to do in response to orders the commission issued April 17.

FERC accepted in part compliance filings from APS (*ER24-330*) and PNM (*ER24-1393*), while directing the utilities to submit further compliance filings.

Issued in July 2023, Order 2023 revised FERC's *pro forma* generator interconnection rules to help clear backlogged interconnection queues across the U.S. It was followed by a clarifying order, Order 2023-A, in March 2024. (See *FERC Updates Interconnection Queue Process with Order 2023*.)

The orders require transmission providers to transition from serial interconnection processes to studying interconnection requests simultaneously through cluster studies.

### APS Filings

APS submitted an initial filing for Order 2023 compliance in November 2023. FERC accepted it in part but told the utility to submit a filing with further revisions to address requirements in 14 areas.

In its subsequent filing, APS proposed adopting without modification the *pro forma* interconnection procedures and agreements for large and small generators (LGIP, LGIA, SGIP and SGIA).

PNM's Western Spirit transmission line. | *New Mexico Renewable Energy Transmission Authority*

In doing so, APS met requirements for the LGIA deposit, affected system study process and modeling, affected system *pro forma* agreements, co-located generating facilities, availability of surplus interconnection service, and modeling and ride-through.

But APS' filing also had "unexplained variations" from FERC's *pro forma* LGIP, LGIA, SGIP and SGIA. In those cases, a transmission provider that's not an RTO or ISO must explain how its proposals are consistent with or better than the Order 2023 provisions.

Some of the variations in APS' filing appear to be typos or minor mistakes, FERC said.

Other variations were deemed to be consistent with or better than what Order 2023 prescribed. On the issue of study deposits, APS proposed a $105,000 deposit that it said better reflected its historical study costs than a FERC-tiered system with deposits ranging from $35,000 plus $1,000 per MW to $250,000.

"We find that [APS'] proposed approach should reduce the number of instances in which an interconnection customer submits an upfront study deposit that ultimately exceeds its actual study costs and APS must then refund those excess amounts," FERC said in its order.

On the topic of allocating cluster study costs, APS changed the allocation method in its initial filing to a method that's consistent with Order 2023. APS will allocate half of cluster study costs per capita among interconnection customers in the cluster and the other half of costs pro rata by megawatt.

In other areas, FERC said APS' proposal partly met Order 2023 requirements but needed further modification. Those include proposals related to site control, commercial readiness and the transition process.

APS' next filing is due in 60 days.

### PNM Filing

PNM submitted its Order 2023 compliance filing in March 2024, with amendments in May 2024 and March 2025.

> **Why This Matters**
>
> In areas of the country without fully organized markets, transmission-owning utilities must be the ones to comply with FERC's landmark order on generator interconnection rules.

Similarly to APS, PNM tackled a long list of requirements by proposing to adopt without modification FERC's *pro forma* LGIP, LGIA, SGIP and SGIA provisions. That included requirements related to commercial readiness, LGIA deposit, co-located generating facilities and availability of surplus interconnection service, among others.

FERC also spotted typos and minor errors in PNM's filing that need fixing.

On requirements for the transition process, FERC accepted PNM's proposal that any interconnection customer assigned a queue position "as of 30 calendar days of the commission-approved effective date of this LGIP" will retain that queue position and may choose to proceed with a transitional cluster study.

FERC said the provision will give PNM's "existing interconnection requests the option to participate in the transition process."

"We reiterate here that the provisions of Order No. 2023 are not intended to interfere with the timely completion of in-progress cluster studies," FERC said in its order.

FERC found that PNM had partly complied with requirements in other areas, including the cluster study process, study deposits and site control.

FERC directed PNM to submit two filings: one within 60 days and the other 60 days before opening the initial interconnection request cluster window. ■

# Load Growth Dominates Discussions at GCPA's Spring Conference

*By James Downing*

HOUSTON — Texas has shown itself as capable as any state of building big things. And ERCOT is the one organized market that saw demand growth over the past two decades as it benefited from population shifts to the Sun Belt and booming industry.

The latest forecasts are so large, however, that meeting whatever fraction comes to fruition is daunting. That issue dominated discussions at the Gulf Coast Power Association's recent Spring Conference. (See *GCPA Hears Different Tales on Texas Load Growth from 2 CEOs*.)

The market's all-time peak is about 85 GW, and forecasts claim that could triple by the end of the decade due largely to new large loads from data centers, cryptocurrency mining, reshoring of industry and hydrogen production.

"I think that's driven by the opportunities that are created by the Texas market, plus, you know, just the natural resources that Texas has," said Goff Policy President Eric Goff. "So, it probably won't be as big as the number ERCOT publishes, in part because they're required to follow a particular methodology established in state law. But, also, it's going to be big."

The industry should take the eye-popping numbers in ERCOT's forecasts with a grain of salt as it does similar figures on the supply side, said American Clean Power Association Senior Director Charlie Hemmeline. ERCOT's queue similarly has eye-popping numbers in terms of nameplate capacity.

"There's a lot of plans," Hemmeline said. "Many of those plans work out, and many don't. And so just being smart about what the future holds."

Texas is trying to get more dispatchable generation onto the grid through the Texas Energy Fund (TEF), which has seen projects drop out recently. (See *2 More Projects Fall out of TEF Loan Program*.)

Calpine has one project competing for state money. Its Vice President of Government and Regulatory Affairs Bryan Sams wondered how generous the Legislature will be, with different amounts allocated in the House and Senate this session.

A GCPA panel with Guidepost Energy's Alexandra Williams, Tradition Energy Vice President Brooke Petosa, ERCOT Large Load Integration Team Supervisor Julie Snitman, Hut 8 Senior Vice President Brad Richter and Zero Emission Grid President Mike Tabrizi. | © *RTO Insider*

## Why This Matters

ERCOT faces the same issues as other parts of the country in integrating new large loads, sending the right signals needed to ensure supply and shoring up its transmission grid. But it is doing so with a unique market and a continued desire from Texas policymakers to preserve its independence from federal oversight.

"I think market design really is the answer for what needs to happen to build plants, but it helps at the margins," Sams said.

The TEF gives the Public Utility Commission a new role, acting like a bank, and it is learning that job on the fly, he added. The program also comes with restrictions that could cause more projects to drop out, such as being required to sell 50% of capacity to the grid. Sams said firms could find a better deal co-locating with a data center and might leave the fund for that option.

"One of the things that I'm watching out of the TEF over the next few years is, do we see more natural gas turbines installed outside of TEF than inside TEF, and if so, what does that say to the health of our market and our market design?" Goff said.

ERCOT is working on new rules to deal with large loads seeking to connect to the grid. Those loads are defined as anything with a demand of 75 MW or above, said Large Load Integration Team Supervisor Julie Snitman. It has some interim rules to catch new sources of demand while more permanent fixes are worked out.

"This era of large loads is forcing us and the entire industry, really, to have to think about planning a whole new way," Snitman said. "I think it's really challenging a lot of our existing and preconceived notions about how to plan, particularly when the assumptions you're making in these planning cases are shifting under you — often quite dramatically and quite quickly."

The customer behind a request can change while it's pending in ERCOT's process, which can change how that load will affect the grid, she added. Some customers have flexible requirements, but others require 24/7 power, and that can change at specific sites while ERCOT examines their impact.

The interim process requires loads looking to interconnect within two years to register with ERCOT. But more customers planning large facilities are getting into the process with longer-term plans than that. Rules for longer lead times begin in May, so some are getting ahead of that.

"Also, I think increasingly there's less and less space available in the near-term system, and a lot of clients are starting to recognize that, and so they're pushing out those interconnect requests a little bit further than that two-year mark in the queue," Snitman said.

Supply chain issues have been well documented on the supply side, but Brad Richter, senior vice president of Hut 8, said his firm, which develops Bitcoin mines and other data centers along with their required energy infrastructure, has seen large loads running into the same issue.

"These 345 breakers, there are two manufacturers of these worldwide," Richter said. "And the interconnection queue on that side of things is also long, and whether you're stepping up or stepping down, you need that equipment."

Other jurisdictions have asked to stop large load development altogether as they've been swamped. At some point, ERCOT might need to weed out unrealistic projects to avoid that situation, he added.

## Prospects for Another Round of Transmission Expansion

Large loads are a huge issue facing planners. They are harder to deal with than renewables because they come online faster and ERCOT cannot curtail customer demand like it can with power plants' excess generation, said Zero Emission Grid President Mike Tabrizi. One area they have in common with renewables is the need for transmission.

"I think the main issue is not supply," Tabrizi said. "The main issue is the transmission. You can have a single line. You can have an unlimited amount of generation on one side of this line. But it doesn't mean that we can transfer all this out to the line, right? So, I think the main fundamental right now is that transmission is not being developed."

Transmission expansion is important to former PUC Commissioner Will McAdams, who runs the McAdams Energy Group. Regulators will decide soon on whether to build 765-kV lines to help to serve Permian Basin oil production in West Texas. If they do, it follows that 765-kV lines will be built in the east of the state to support load growth around its major cities and from large customers.

"It's a no-brainer to me, because that's the one thing that we can guarantee the immediacy, or have more control over the immediacy, of integration and interconnectivity across the system," McAdams said.

The Legislature has indicated it wants to keep ERCOT mostly isolated from the rest of North America's grid. That will require more transmission within Texas to manage the new demand and supply.

"Then we need an extremely integrated system within that island in order to support ourselves," McAdams said.

While ERCOT is likely to keep its jurisdictional status, one line that could increase its exposure to the Eastern Interconnection is Pattern Energy's Southern Spirit line. It would connect to MISO South with full construction scheduled to start in 2029. Pattern Vice President of Origination Holly Adams noted that her firm has another HVDC merchant project linking New Mexico and California, while Grid United plans one to connect ERCOT and SPP.

"Our opinion is all the projects on this list should actually get built out," Adams said. "There's a lot of need for it. But I do think the ERCOT to MISO South, just in proximity for the Texas triangle, the big load growth — I think it's really important to get that project built out."

NERC's studies on interregional transfer capability have shown that connecting ERCOT to MISO South and SPP would bring reliability benefits, she added. (See *NERC Files ITCS to FERC, Meeting Congress' Deadline*.)

NERC studies have shown interregional HVDC lines that are long enough to get into a different weather pattern can improve the reliability of the grid, said Lasher Energy Consulting's Warren Lasher. But the connection to vastly different market regimes would lead to less generation in Texas over time as the resources on the other side do not face the same competitive pressures that come with ERCOT's unique market.

"It reminds me of the canals around Chicago, where they're concerned about invasive fish getting into the Great Lakes," Lasher said. "You've just got to be careful about where you build a connection from one point to another because of the long-term impacts."

## Where Will Needed New Generation Come from?

While transmission is key to serving new load, it cannot accomplish that without enough electrons. That means new generation to meet rising demand.

Vistra Energy develops solar, batteries and natural gas units, but it needs offtake agreements with customers to make renewable projects profitable enough to build. The revenues required for new gas plants increasingly are requiring that too, said Stacey Doré, its chief strategy and sustainability officer.

"We often say in rooms like this, if there are any corporate offtakers for gas plants that want to sign up for a PPA, come and talk to us," Doré said. "And we typically don't have a line out the door waiting for that."

Gas plants need market signals to get built. While Vistra is developing new peaker plants in West Texas that are up for the Texas Energy Fund, it is hedging its bets and could back out of those plans if prices are not enough to justify the final investment, Doré added.

"In ERCOT in particular, where there's no capacity market, customer choices are driving what gets built, and the customers are demanding renewables, even while our policymakers are saying we need more dispatchable generation," Doré said. "So I think that's a disconnect that we still haven't quite solved in ERCOT yet."

The existing thermal fleet ran only at 50% capacity factor last year, which means there still is headroom in current generation, she added.

The use of batteries has increased dramatically in ERCOT, with more than 10 GW today, said Jupiter Power CEO Andy Bowman, whose firm develops energy storage projects.

"I think with batteries, they come along so quickly that the market opportunity is still coming together and being articulated in state policy and in ISO policies," Bowman said. "The opportunity here in ERCOT is very different. The first six projects that we built were built on balance sheet. These were projects that just operated in the market. They operated largely as a natural gas power plant would."

Jupiter is developing more batteries that are contracted with PPAs, instead of just earning in the wholesale markets, he added. ERCOT will keep building solar and batteries, along with some wind and natural gas, and that will lead to more ramping needs and volatility.

"There's a pretty good stripe of opportunity that a lot of outside forecasters, which we rely on in our finances and so on, are seeing a really solid revenue opportunity for batteries fitting into ERCOT extending through 2040," Bowman said.

With a demand super cycle driving investment, there's no shortage of capital to support new supply. But NRG Energy and other generators have to make enough money to justify investing it, said its Executive Vice President Robert Gaudette.

"Thermal shares a lot of the same question marks as far as, OK, well, 'who's wearing a risk on tariffs, or who's wearing a risk on XYZ and all that,' but there's no shortage of capital," Gaudette said.

A lot of that capital is being deployed into existing assets through merger and acquisition activity, said Vistra's Doré.

"You can buy those plants for cheaper than you can build new plants," Doré said. "And as long as that's the case, capital is going to flow to those assets, because obviously they're going to have a better return. So, then you have to ask yourself, what does the market need to do to incentivize new generation if we need new generation and how much of it do we need?"

PJM has built three times the amount of natural gas as ERCOT has in the past decade, but it has a capacity market. While that construct is not likely to be added to the Texas grid, Doré argued that something has to change.

"You've got to come up with some market mechanism that rewards reliability, because the fact of the matter is we have plenty of energy," Doré said. "I mean, on your average day in ERCOT, we have a lot of excess energy. We have plenty of energy. What we don't have quite enough of is the capacity that's needed to fill in the gaps on the peak days when perhaps renewables, for example, are not performing as expected." ■

# Texas RE Endorses 6.4% Budget Increase for 2026

The Texas Reliability Entity's Member Representatives Committee has unanimously approved the entity's 2026 business plan and budget, which is within 1% of projections.

The proposed $21.598 million budget is a $1.3 million increase (6.4%) over the 2025 budget. It adds three staffers to help handle the organization's increasing workload and a 4% merit increase for personnel.

"We're looking at the challenges that we're seeing with significant growth and the complexity of the work that we're having to do, and the changing landscape with the resource mix," Texas RE CEO Jim Albright told the MRC during the April 17 call.

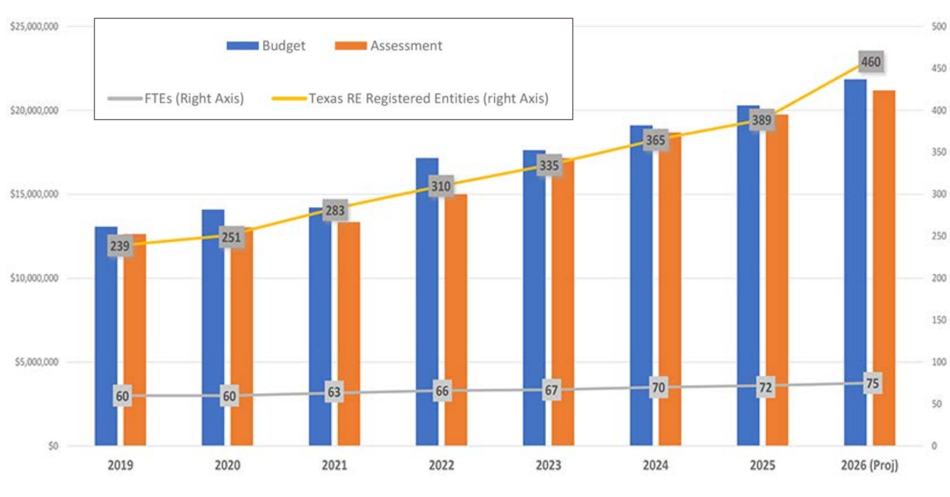
Albright said Texas RE has the lowest number of statutory full-time equivalents (72) in the ERO Enterprise but the second-highest number of registered entities (389). It has the lowest NERC ERO Enterprise Program funding per registered entity, he said.

At the same time, the increase and types of registered entities are increasing compliance-oversight engagements. New standards or requirements in compliance areas and increased expectations from NERC and FERC for new entity outreach and engagements also are taxing Texas RE's staff, COO Joseph Younger said.

Looking ahead, Texas RE is projecting a 7.8% budget increase in 2027 from 2026 and a 5.5% increase in 2028 from 2027.

Texas RE will post the budget for members' comments. The complete plan and budget will be presented to the board May 14 for its approval. ■

*— Tom Kleckner*




The Texas RE is attempting to close the gap between its FTEs and registered entities. | *Texas RE*

# GCPA Hears Different Tales on Texas Load Growth from 2 CEOs

## Cautious Take on Growth Projections v. Warnings About Industry Preparedness

*By James Downing*

HOUSTON — Two power industry CEOs at the Gulf Coast Power Association's spring conference offered two different takes on ERCOT load growth over the rest of the decade — and how the sector should deal with a potential doubling of peak demand by 2031. (See *ERCOT: 60 GW in Additional Demand by 2031*.)

"Everything's bigger in Texas — but is it really that big?" Calpine CEO Andrew Novotny said at the event April 16. "Just a couple weeks ago, we were dealing with a pretty large ERCOT load forecast that was calling for more than 60,000 MW of growth. As of … really just last week … that 60,000 MW was turned into more than 100,000 MW of forecasted demand between now and 2030."

Those numbers are creating a lot of angst in an industry that has dealt with steady load growth for decades, but not a more than doubling of demand in five years, he added.

Part of that forecast is 13 GW of hydrogen electrolyzers, which were already running into major cost issues before the election scrambled federal support for clean fuel solutions, Novotny said. An additional 9 GW was for cryptocurrency mining facilities, which, like hydrogen electrolyzers, would represent price-responsive demand and not have major impacts on the market's peak.

"We need to get more transparency in certain data, but they're all curtailing anytime the price takes over $200," Novotny said. "Bitcoin is soaking up the cheap wind and solar that exists and curtailing, providing their power back to the grid anytime the grid needs it."

### Why This Matters

ERCOT is not alone in offering eye-popping projections of demand growth. While the huge forecasts might not materialize, meeting new demand will require major efforts from the industry and regulators.

Rockland Capital's Scott Harlan and AlphaGen Chairman Curt Morgan presenting at GCPA's Annual Spring Conference on April 16. | © RTO Insider

The biggest chunk of the forecast is 70 GW of new data centers, compared with fewer than 3 GW of data centers in Texas today. That would lead to $2 trillion of investment in the state over five years.

"I think it's impossible because it's more than two times the amount of chips that Nvidia is expected to make over the next three years," Novotny said.

The Nvidia GB 200 chips cost $70,000 apiece and are needed for the artificial intelligence applications driving the data center boom. One of those chips uses the same amount of power as two-and-a-half average Texas homes, Novotny said.

If Nvidia can double its growth rate, it will sell enough chips in the next three years that, with associated cooling demand, they will require 34 GW to operate. That could increase to 49 GW by 2030, which would be short of the 70 GW projected for Texas — an outlook that doesn't consider other data center markets that also are projecting huge growth.

To be included in the forecasts, many of the planned data centers need little more than certification from a corporate officer at the company constructing them, which requires a deposit of several million dollars — a drop in the bucket, given that the industry could spend $300 billion.

"If we go after this hard as Texas, we can probably get somewhere between [5,000] and 10,000 megs of these things by 2030," Novotny said. "So a number like 7,000 MW seems like a good midpoint guess to make. But I mean, aren't we scared to even get that? I mean, how much resource adequacy challenge will we have?"

### Markets that Work

AlphaGen Chair Curt Morgan, who was once CEO of Texas' largest generator, Vistra Energy, later that day offered a more cautionary — but bullish — view, colored by a fear of the industry missing out. Morgan came out of retirement because he wanted to participate as the industry dealt with national-scale load growth for the first time in decades.

"This is the first time in my career I've seen a demand-led cycle," Morgan said. "Usually, it's an overbuild on the supply side. But my biggest concern right now is that if we get this wrong, then the [data center- and manufacturing-led] growth coming to this country is going to find a home somewhere else."

The power sector can meet the challenge, Morgan said, but worried it will not unless competitive markets send the right price signals.

"We need markets that work, and we need the courage of our elected officials and our regulators to put a market system in place and let it work," he added.

The evidence from the Texas Energy Fund does not bode well for new builds, as the repeated exits from that program — which offers government subsidies for dispatchable power plants — show that many do not see enough revenues from ERCOT's market to support the buildout. (See related story *2 More Projects Fall out of TEF Loan Program*.)

That kind of buildout has been done before, given that the construction of the entire power grid was supported by the balance sheet of large industrial customers who were its largest users.

"Now we're talking about data center growth, and the people who are going to benefit from data centers have to put their balance sheet out there to support power growth," Morgan said. "They can't sit it out."

Morgan said he tells people he gets paid to be paranoid and right now he is worried the industry is going to miss the huge opportunity in front of it.

"I'm really concerned because not everybody's on the same page and there are politics being played," Morgan said. "And I understand it, you know; it's just going to be an expensive buildout."

The big tech firms that are driving the data center boom need to help because the cost shifts to other consumers would otherwise become politically infeasible,


Calpine CEO Andrew Novotny addresses GCPA on April 16. | © *RTO Insider*

meaning the country misses out on the economic opportunity, he added.

Markets have overseen huge resource expansions in the past, including the combined cycle boom at the dawn of electricity sector restructuring, which quickly turned into a bust and a wave of independent power producer (IPP) bankruptcies.

"Every single publicly traded IPP in this country went in and out of bankruptcy," Morgan said. "Not one penny of those bankruptcy costs was ever borne by a captive ratepayer. The shareholders paid for that. To me, that is the essence of competition."

## 'Shark-infested Waters'

Some want to get away from that model and are using prospective demand growth as a reason to push for utility-owned generation in states that have banned it for decades, Morgan said.

Utilities can often still set up competitive subsidiaries that sell generation in the states where they operate, but they would rather put the risk of new power plants on the backs of consumers in rate base, he said. (See *Utilities Pushing for Return to Owning Generation in Pennsylvania*.)

"That's a chicken-you-know-what," Morgan said, avoiding the expletive. "Come in here, into the shark-infested waters, and figure out how to make it work just like we are. And I'll tell you, if we get into a situation where we start to bifurcate markets, it'll never win. I'll tell you why, because you'll have retirements that will always outstrip new build, and you'll just make a bad situation worse."

When it comes to Texas, Morgan said the ERCOT market needs to send price signals that support more dispatchable generation that will be needed to meet the growing demand. Capacity markets are a third rail in Texas, but some kind of price signal through ancillary services could work.

"Markets will overbuild themselves if they believe that there's a reasonable chance of getting return on investment and they can trust that the market scheme is going to stay the same year after year," Morgan said. "If they think it's going to change on them, then markets will not invest."

After Winter Storm Uri, the PUC cut ERCOT's price cap down to $5,000/MWh but ordered more frequent triggering of scarcity pricing and implantation of real-time co-optimization of energy and ancillary services. Those efforts have not worked, especially with the looming need to meet data center demand, Morgan said.

"I think we need to have something that provides the chance for people to get a return of and on their investment," Morgan said. "We need to leave it in place. We have to have the courage to trust that it's going to happen. If we do that, there is a ton of capital out there right now that would love to find a home and support this demand buildout."

Another needed regulatory fix involves the natural gas industry, which is going to become more important going forward. Morgan said.

"I don't think there's a regulatory body that really holds anybody's feet to the fire on the gas side of the business," he said.

The Texas gas industry suffered outages during Uri and, like the power industry, does not want to see a repeat, but regulation of its interstate pipelines is very light, he noted.

Regulators, including FERC, have taken a more laissez faire approach to that industry, and that has its advantages, but in Texas, it is less regulation and more "advocacy," he said

"Nobody even batted an eye when we went from less than $3 to $300 gas during Uri," Morgan said. "'Ah, that's just how that market works.' I mean, that excuse was $8 billion of money that was basically sent through the [local delivery companies] for gas charges that occurred during Uri … and they securitized it and are paying it off over a 20-year period." ■

# PUC Staff Urges Approval of 765-kV Lines to West Texas

*By Tom Kleckner*

The Texas Public Utility Commission's staff has recommended that the commission approve construction of three 765-kV transmission lines, rather than 345-kV lines, into the petroleum-rich Permian Basin to improve the region's reliability (*55718*).

Staff said in an *April 17 memo* that after "careful deliberation," they found the 765-kV import paths' long-term benefits justify an additional 22% increase in estimated capital costs.

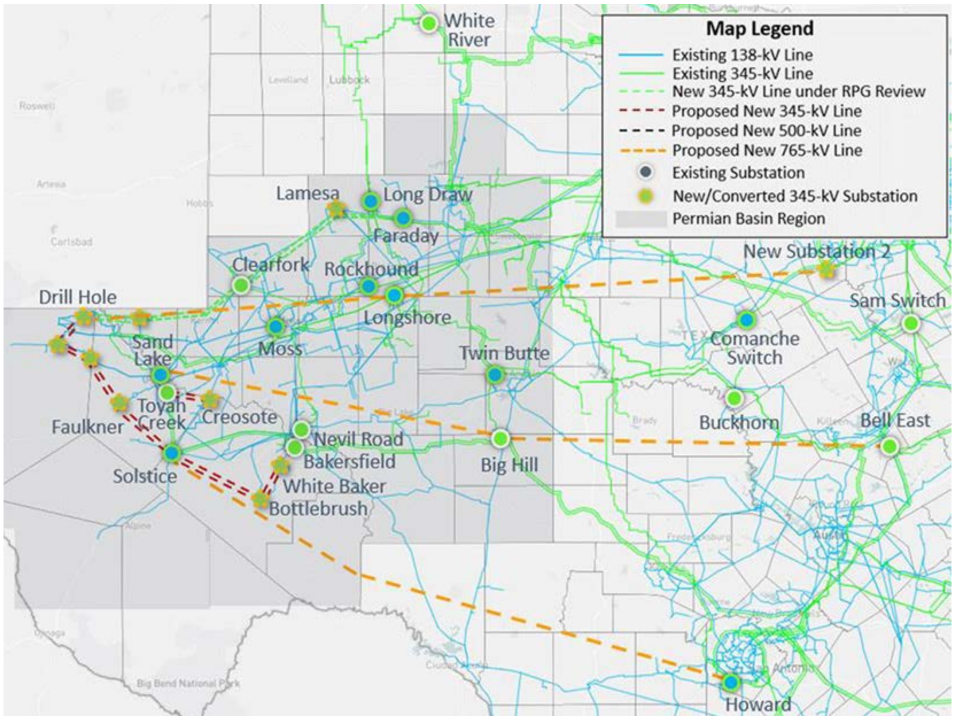
Based on confidential cost filings from transmission providers and updated estimates from ERCOT, staff said the 765-kV option's expenses have increased from $9.06 billion to $10.11 billion. In comparison, the 345-kV option has increased from $7.69 billion to $8.28 billion.

"Staff is convinced that the commission has a unique opportunity to timely address ERCOT's current and expected rapid load growth by deploying an extra-high-voltage transmission network at a reasonable economic cost," they wrote. "This decision balances forecast uncertainty, cost and reliability with establishing a forward-thinking policy decision that ably prepares the ERCOT region for the future."

The PUC is expected to discuss the recommendation at its April 24 meeting. The commissioners have promised a decision by May.

## Why This Matters

The Texas PUC's staff recommends the commission approve the construction of three 765-kV transmission lines, rather than five 345-kV facilities, to meet increasing load in the petroleum-rich Permian Basin. They say the 765-kV option's long-term benefits outweigh a recent 22% increase in estimated capital costs.



ERCOT's proposed 765-kV import paths into the Permian Basin. | *ERCOT*

Staff said 765-kV lines' lower impedance than that of 345-kV lines increases power flows. They said ERCOT indicates the 345-kV plan has an incremental transfer capability of 1,340 MW while the 765-kV plan can transfer 2,105 MW.

"The higher value for the 765-kV transfer indicates it can carry more power, and therefore serve additional load in the Permian," staff said, noting the "uncertainty inherent in forecasting load out as far as 2038."

"The ability to serve more load could offer a buffer for the 2038 load forecast and may avoid or delay the need to build additional transfer paths in the near future," they said. "Therefore, the increased capital cost of installing 765-kV infrastructure could function as a present investment that may save additional infrastructure costs in the future."

Staff also said the 765-kV option's transfer capability will help ERCOT better manage the "uncertainty surrounding load and generation siting decisions" and the flexibility for power flows to shift due to changes in location and the nature of future load and generation.

Because the 765-kV plan allows greater transfer capability, ERCOT designed the 765-kV plan using only three paths totaling about 1,255 miles of right-of-way, staff said. The 345-kV plan, with five paths, would require about 1,676 miles of ROW.

The 765-kV lines, if built, could be Texas' first. SPP in December approved a transmission plan that included its first 765-kV project in Southwestern Public Service Co.'s West Texas and New Mexico region. (See *SPP Board Approves $7.65B ITP, Delays Contentious Issue*.)

"765-kV technology may be new to Texas, but it is not a new technology," staff said, pointing to American Electric Power's "decades of experience" with EHV lines. AEP has offered other transmission providers access to its 765-kV standards and guidance, they said.

ERCOT, at the PUC's direction, filed its *reliability plan* for the Permian Basin in July 2024. The plan included the 345-kV and 765-kV import paths and a 2038 need date. The commission *approved* the plan in October 2024 but reserved a decision on the voltage level by May 2025. (See *Texas PUC Approves Permian Reliability Plan*.) ■

# 2 More Projects Fall out of TEF Loan Program

By Tom Kleckner

The troubled Texas Energy Fund has lost two more projects from its original list of applicants, raising questions about its ability to quickly add 10 GW of gas-fired dispatchable resources to the ERCOT grid.

Connie Corona, executive director of the Texas Public Utility Commission, said in identical filings April 15 that both applicants had "failed to meet due diligence requirements." The orders are not subject to rehearing or appeal requests, she said (*56896*).

The loss of the two gas-fired projects from the *list of applicants* takes another 1,056 MW out of the TEF's In-ERCOT portfolio. The 14 remaining applications total 7,284 MW of capacity and about $3.96 billion in requested loans, a PUC spokesperson said.

One of the projects belonged to Ember-Clear and Jupiter Island Capital, which *proposed two 900-MW* projects west of Houston. The other was proposed by Frontier Group of Companies for the Lone Star Industrial Park in East Texas, comprising two gas units with 162 MW of capacity. A 40-MW natural gas unit, commissioned in 1954 and once operated by Southwestern Public Service, sits in the park.

Four other companies have also withdrawn projects since 2025 began. (See *Texas Loan Program Loses 2 More Gas Projects*.)

Stoic Energy's Doug Lewin said the TEF's travails only emphasize the need for renewable energy and storage. He said that given ERCOT's current projections of 44 GW of demand growth in the next four years ("As their midline," he noted), Texas will still be 34 GW short even if the fund meets its 10-GW goal.

"It's going to be even harder to meet rising demand without robust renewable and storage growth. There's just no other resource else that can be developed that quickly," he told *RTO Insider*.

More than 5,712 MW of capacity has been withdrawn or denied from the *original submitted applications*. More than 40% of the projects (4,965 of 12,249 MW) advanced to due diligence now have been withdrawn or denied.

The PUC has said staff intend to advance additional applications to due diligence review at a future open meeting. The commission next meets April 24.

George Castellanos, chief power officer for Frontier, said the New York-based firm was disappointed with the decision but praised the TEF's review process.

"We remain confident in the strategic value of our project to support Texas' long-term reliability goals," he said in an email to *RTO Insider*.

Castellanos said the firm plans to continue the industrial park's development. That includes reactivating the gas unit on site and adding another 114 MW of new capacity.

The state legislature created the TEF in 2023 to add more dispatchable generation to the grid. Voters approved it later that year. Managed by the PUC, it is designed to provide grants and loans to finance construction, maintenance, modernization and operation of electric facilities in the state.

The fund comprises four programs: In-ERCOT Generation Loans, In-ERCOT Completion Bonus Grants, Outside-ERCOT Grants and the Texas Backup Power Package. ■

The existing 1950s-era gas unit at Lone Star Industrial Park | *Lone Star Industrial Park*

## Why This Matters

The Texas Energy Fund was designed to quickly add 10 GW of gas-fired generation to the ERCOT grid. The latest rejected projects leave Texas with less than 7.5 GW of capacity in a portfolio, with some still undergoing due diligence review.

# ISO-NE Prepares Expedited Filing After Ruling on Order 2023 Compliance

*By Jon Lamson*

The NEPOOL Transmission and Markets Committees voted April 17 to support an ISO-NE proposal to adjust several key dates and deadlines in its compliance proposal for FERC Order 2023, which the commission approved April 4. The committees also voted to support an amendment by RENEW Northeast to extend the deadline for late-stage projects to complete their system impact studies (SISs).

FERC's ruling accepting ISO-NE's Order 2023 compliance filing did not alter the RTO's proposed timeline for its transition process, which includes dates and deadlines that have passed and no longer are viable. (See *FERC Approves ISO-NE Order 2023 Interconnection Proposal*.) To amend these issues, ISO-NE plans to file "narrowly tailored tariff revisions to only adjust transition related dates in the compliance proposal by approximately one year."

These changes would allow the RTO to align its transitional capacity network resource (CNR) group study with the 2025 Interim Reconfiguration Auction Qualification Process — a necessary step to run the CNR study in 2025 — and start the transitional cluster study (TCS) in October.

The transitional CNR study is intended to enable interconnection customers with complete SISs to achieve capacity interconnection rights, while the TCS will be open to all other projects with valid interconnection requests. ISO-NE will use the results of the CNR study as an input to the TCS.

The RTO plans to make a Section 205 filing with the timeline changes "immediately following the May 2025 Participants Committee meeting, and request a next day effective date for the revisions to adjust the dates," said Alex Rost, director of transmission services at ISO-NE.

Rost said ISO-NE has closed the queue again after opening it briefly April 1 and noted that only resources with valid interconnection requests as of June 13, 2024, will be eligible to enter the TCS. The next opportunity for resources to enter the interconnection queue will be the initial cluster request window, which will open after ISO-NE completes the TCS. If the TCS begins in October 2025, the queue would be slated to reopen in late 2026.

## Why This Matters

The filing would enable ISO-NE to preserve its timeline for transitioning to the new interconnection process, with most key dates pushed back by about a year.

Because the new interconnection rules already are in place — and technically took effect Aug. 12, 2024, despite FERC not ruling until April 4, 2025 — ISO-NE has stopped work on all ongoing interconnection studies under the prior rules, Rost said. He noted that "any on-hand deposits associated with an [interconnection request] that is eligible for the transition can be applied to transition studies."

He said ISO-NE will honor any SISs completed between the official effective date and the date ISO-NE received the ruling, as these studies were completed under the rules that were in place at the time.

Abigail Krich of Boreas Renewables, speaking on behalf of RENEW Northeast, proposed to amend the expedited filing to allow late-stage requests to continue their SISs until Aug. 29, 2025.

"The only component of the ISO's originally proposed transition that they do not propose to shift forward by [about] one year is the late-stage SIS completion deadline," Krich wrote in a *memo* prior to the meeting. She noted that ISO-NE initially proposed to continue working on late-stage SISs through Aug. 30, 2024.

Krich said late-stage projects already could have spent "on the order of $250,000" on interconnection studies, which would be invalidated if the studies are not completed prior to the TCS. She said there appears to be 10 or fewer projects that could be eligible for this late-stage treatment.

"These [interconnection requests] remain eligible to enter the TCS this fall, but doing so will cost them more money, delay their interconnection and put them at risk of larger withdrawal penalties," Krich said. She added that completing the system impact studies for as many projects as possible prior to the TCS would reduce the size, complexity and withdrawal risks of the study.

"Continuing work on the few interconnection requests that would potentially be identified as 'late-stage' would be a relatively small amount of work for the ISO's interconnection team and should not take away from the ability to implement the remainder of the Order 2023 transition," Krich added.

Developers with late-stage interconnection requests have expressed strong interest in continuing their studies and argued it is in the region's best interest to complete these studies to help bring new resources online as quickly as possible.

ISO-NE expressed concern about potential issues associated with reintroducing the old interconnection rules for late-stage requests, and that incorporating RENEW's proposal into its filing could complicate the approval of its proposed timing changes.

The committee voted to support both RENEW's amendment and ISO-NE's proposal without the amendment. ISO-NE said it will consider its options before bringing the proposal to the NEPOOL Participants Committee on May 1.

ISO-NE also plans to work with stakeholders to make a second filing to address the series of relatively minor issues that FERC identified with its Order 2023 compliance proposal. This filing is due in early June. ■

# ISO-NE Cuts Winter, Summer Peak Load Forecasts for 2033

By Jon Lamson

ISO-NE *plans to cut* its winter peak load projection for 2033 by 7.2% and its summer peak projection by 1.8%, Victoria Rojo, supervisor of load forecasting at ISO-NE, told the NEPOOL Reliability Committee (RC) on April 16.

The cuts are driven largely by significant reductions to ISO-NE's electrification projections for heating and transportation, which Rojo discussed at length with stakeholders at the RC in March. (See *ISO-NE Scales Back Vehicle, Heating Electrification Forecasts*.)

The RTO has broadly overhauled the methodology behind its Capacity, Energy, Loads and Transmission (CELT) reports to incorporate more granular hourly demand forecasting and climate-adjusted weather data across 70 weather years.

While ISO-NE still anticipates that demand growth will accelerate in the coming years, the results show a significant drop in expected demand relative to the RTO's forecasts from the past few years. Compared to its 2024 forecast, ISO-NE has cut its 2033 summer peak projection by 474 MW and its 2033 winter projection by 1,937 MW. It also reduced its annual net energy projection for 2033 by 9.3%.

Rojo also presented the RTO's final draft forecast for behind-the-meter (BTM) solar. ISO-NE anticipates that BTM solar production will nearly double between 2025 and 2034, growing by about 570 GWh annually.

ISO-NE plans to use its previous load forecasting methodology to calculate the installed capacity requirement for its 2026/27 and 2027/28 annual reconfiguration auctions. It will roll out the new methodology for the 2028/29 capacity commitment period in coordination with a proposed overhaul of its capacity market. (See *ISO-NE Gives Updates on Prompt, Seasonal Capacity Market Changes*.)

Because the new methodology incorporates energy efficiency into the base forecast and eliminates the need to separately forecast energy efficiency, using the old methodology will prevent "unintended market outcomes that could arise from a midstream transition," ISO-NE wrote in a *memo* published in late March.

The forecast values are subject to change; ISO-NE plans to finalize and publish its CELT forecast May 1.

## Regional Energy Shortfall Threshold

Also at the RC, ISO-NE said it *plans to focus* its regional energy shortfall threshold (REST) on the most extreme 0.25% of modeled reliability scenarios, a risk level that equates to one event occurring every 90 winter seasons.

The REST is intended to quantify New England's "level of risk tolerance with respect to energy shortfall during extreme conditions in a season" and help "inform regional decision-making about managing potential energy shortfalls."

ISO-NE has proposed metrics related to shortfall duration and magnitude, which it will use to evaluate shortfall risks for the most extreme 21-day cases ISO-NE models. (See *ISO-NE Details Regional Energy Shortfall Threshold Metrics*.) Jinye Zhao of ISO-NE said basing the REST threshold on the 0.25% tail of cases would enable the RTO to focus on high-impact cases that have a reasonable chance of occurring.

The RTO plans to propose initial threshold values for these duration and magnitude metrics at the RC in June.

## Operating Procedure Changes

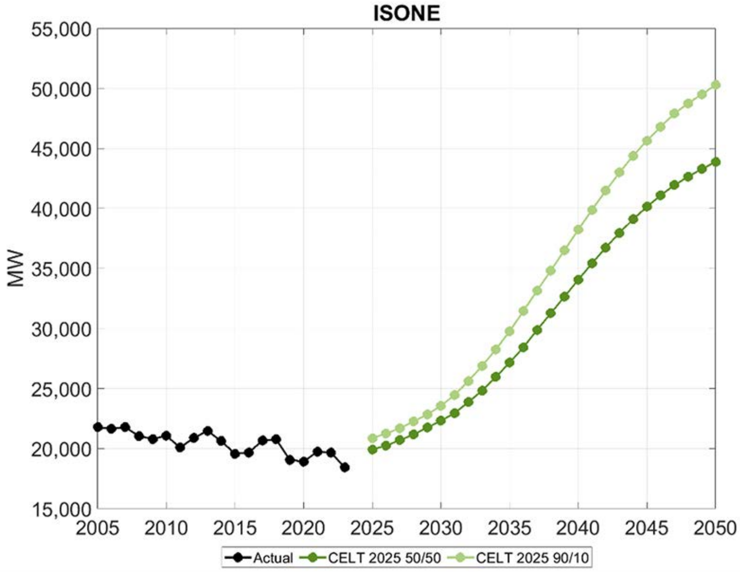
Also at the meeting, the RC voted to support changes to ISO-NE's operating procedures for transmission outage scheduling and metering and telemetering criteria.

The metering changes would allow an increased equipment temperature range "if data center-type HVAC redundancy is in place," and add new automatic voltage regulator rules for composite units.

The transmission outage scheduling changes would "clarify that Long-Term Transmission Outages may be approved without having to first be interim approved at the discretion of the ISO," Anthony Stevens of ISO-NE said. ■

## Why This Matters

The significant changes to ISO-NE's demand forecast highlight the challenges of predicting the pace of electrification amid political turmoil.




ISO-NE winter net peak 90/10 and 50/50 forecasts | *ISO-NE*

# New Hampshire OCA Raises Concern about National Grid Asset Condition Projects

*By Jon Lamson*

The New Hampshire Office of the Consumer Advocate (OCA) has expressed concern that there is "reasonable grounds to object to at least some of costs" of two asset condition projects proposed by National Grid and argues the transmission owner should justify why the reliability needs addressed in its proposals should not be addressed through a competitive procurement process.

The OCA *letter*, published April 18, is the latest in a series of complaints by New England states and consumer advocates about a lack of transparency and oversight into the planning and approval processes for asset condition projects.

National Grid proposes to rebuild, reconductor and install optical ground wire on *two lines* in northeastern Massachusetts for about $271 million. For both projects, National Grid proposes to expand the scope of work beyond the most critical needs, in part to prevent more projects addressing reliability issues expected to arise over the next 10 years.

Incumbent transmission owners typically have the authority to determine when and where asset condition projects are needed to address aging or deteriorating infrastructure and pass the costs on to ratepayers through formula rates. Asset condition projects are not subject to competitive solicitations for proposals.

However, because the issues addressed by the proposals overlap with reliability issues identified by ISO-NE's Boston 2033 Needs Assessment study and 2050 Transmission Study, the OCA argued the issues may require competitive procurements.

"It remains unclear why a competitive solution process is not being used for these projects," the OCA wrote. "It appears that the only reason a competitive process is not happening is because National Grid has chosen to treat these projects as [asset condition projects] and the ISO has disclaimed any responsibility for testing that choice."

## Why This Matters

While ISO-NE has said the results of needs studies do not affect transmission owners' abilities to pursue asset condition projects, the OCA expressed concern that transmission owners may be able to avoid competitive procurement processes by introducing or expanding the scope of asset condition projects.

The OCA highlighted ISO-NE *tariff* language that states that "where the solution to a Needs Assessment will likely be a Market Efficiency Transmission Upgrade, or where the forecast year of need for a solution that is likely to be a Reliability Transmission Upgrade is more than three years from the completion of a Needs Assessment, the ISO will conduct a solution process based on a two-stage competitive solution process."

The OCA said there appears to be enough time to pursue competitive procurement because the projects are not scheduled to begin construction until the second half of 2028 and are categorized by the Boston 2033 Needs Assessment as non-time-sensitive.

"The objection isn't necessarily to the projects themselves. … The system might genuinely need this to happen," said Matthew Fossum, assistant consumer advocate at the OCA. "My concern is that this could allow National Grid to sidestep a competitive process that could meet the needs at a lower cost."

The National Grid proposals are not the only asset condition projects to draw scrutiny in the past year. In August 2024, the New England States Committee on Electricity (NESCOE) expressed concern about a "lack of compelling evidence to support the scope" of a $385 million asset condition project in New Hampshire. (See *New England States Raise Alarm on Eversource Asset Condition Project*.)

Meanwhile, in March, NESCOE *called for* a "holistic, regional planning process" to ensure a proposal by Eversource to replace nearly all its underground transmission cables in the Boston area is conducted as cost-effectively as possible. NESCOE estimated the project's costs could be in the $8 billion to $9 billion range "based on recent similar cost estimates."

At the urging of the states, the region's transmission owners have taken steps in recent years to increase transparency around asset condition spending, including standardizing the format of informational presentations made to the ISO-NE Planning Advisory Committee, allowing stakeholder feedback and creating an asset condition project database.

However, states and consumer advocates continue to argue there's inadequate oversight for the projects, which make up a growing portion of the region's transmission costs. In a March filing to FERC, NESCOE urged the commission to adopt "NESCOE's long-standing request to implement an Independent Transmission Monitor" (*EL25-44*). (See *New England Officials Discuss Tx Oversight and Rising Energy Costs*.)

Fossum said it was concerning that National Grid took nearly five months to respond to his request for more information on the projects, and he said the response he received was "essentially a non-answer."

National Grid declined to comment for this story, but wrote in a *response* to the OCA on April 15 that the expanded scope of the two asset condition projects will provide a longer-term solution "with the added benefits of also addressing future reliability needs."

It also included a response from ISO-NE, which said "asset condition projects will move forward independent of whether there are any [ISO-NE-]identified needs on the facility, resulting from Needs Assessments, Public Policy studies or Longer-Term Transmission Studies." ■

# End Users Push MISO for More Intensive Cost Overrun Evals on Tx Projects

By Amanda Durish Cook

MISO's end users continue to call for a more stringent variance analysis, the review process MISO uses to investigate transmission projects that incur cost overruns or encounter other difficulties.

At MISO's April 15 cost allocation meeting, attorney Ken Stark, representing end-use customers, called for more "insight and transparency into" the variance analysis as well as a lower, 10% threshold on cost overruns to trigger the analysis.

Stark said the Organization of MISO States (OMS), or the Independent Market Monitor, could play a role in evaluating project costs as part of the analysis. He said OMS and the IMM could sit in on MISO's confidential initial inquiry stage, then offer advice to the RTO.

Stark said MISO's Board of Directors could use an expanded authority to review and issue a final determination on triggered projects, either accepting cost increases, recommending changes or making the call to suspend or cancel projects.

The end-use sector said MISO also should consider incorporating a "feedback loop," where after a variance analysis, MISO publishes a proposed mitigation plan open to stakeholders' reactions over 30 days. Stark also said MISO could file an annual report with FERC summarizing any variance analyses it performed.

The end-use customer sector and the Coalition of MISO Transmission Customers have said MISO's 25% cost overrun trigger to study regional projects is too high and should be lowered to about 10%. (See *Stakeholders Want More from MISO on Tx Project Cost Containment*.)

MISO staff perform variance analyses on regionally cost-shared transmission projects that encounter schedule delays, permitting challenges or significant design changes or experience at least a 25% cost increase from original estimates. The studies also are triggered when developers find themselves unable to complete the project or if they default on the terms of their developer agreement.

After completing the analysis, MISO can either let a project stand, develop a mitigation plan for it, cancel it or assign it to different developers if possible. A committee of MISO employees selected by executives makes calls on how to deal with such projects.

© RTO Insider

## Why This Matters

MISO's end-use customers remain adamant that more expensive transmission investments means the RTO needs to keep a closer eye on when its regional transmission projects go over budget.

Stark said SPP's business practice manuals require projects to get a check-in at a 10% overage and undergo a review at 20%.

"Given the sheer investment that's happening, even a 10% overrun is significant from a cost standpoint," Stark said. "We feel very strongly that the trigger should be lower given the lack of projects that go through the process."

Werner Roth, an economist with the Public Utility Commission of Texas, said he was uncomfortable with OMS conducting an additional review on cost increases in cases where projects haven't yet been assigned a proceeding at a state commission.

Sustainable FERC Project's Natalie McIntire said she's concerned a more sensitive study process would have MISO reviewing otherwise routine cost increases.

"There are a variety of reasons for all kinds of cost increases for all products we use day to day," she said. "We don't want to have this sort of thing triggered for every project MISO approves."

Stark agreed that he didn't want MISO to be "bogged down."

Other stakeholders said the IMM shouldn't be prescribed transmission monitoring duties at a time when MISO is seeking to clarify with FERC whether

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# Louisiana PSC Scraps Statewide Energy Efficiency Program

By Amanda Durish Cook

## Why This Matters

Louisiana's Republican regulators have dismantled the statewide energy efficiency program that has been in the works since 2010 and never got off the ground. Some commissioners have vowed to come up with substitute rules before the utility-led setup expires at the end of 2025.

The Louisiana Public Service Commission abruptly pulled the plug on its long-awaited, statewide energy efficiency program weeks after selecting a contractor to measure savings.

The commission voted 3-2 along party lines at an April 16 *meeting* to "cease working toward" its statewide energy efficiency program that was more than a decade in the making. A companion vote that would have directed commission staff to draft new energy efficiency rules for a public entity program failed, with Commissioner Jean-Paul Coussan flipping his vote for the second roll call due to what he called confusing language. Commissioners Foster Campbell and Davante Lewis voted against cutting the statewide program and the new rule directive.

The commission terminated its contracts with APTIM to administer the program and Tetra Tech to measure savings of the program. The decision came less than a month after commissioners selected Tetra Tech's bid for measurement and verification of energy savings. (See *Louisiana PSC Leaves Statewide Energy Efficiency Program As Is For Now*.)

Chair Mike Francis, who introduced the motion to end the program through a *supplemental agenda* published fewer than 48 hours prior to the meeting, said an independently operated energy efficiency program appeared to be too confusing and too expensive.

The meeting took place at a golf resort in Many, La., a more than three-hour drive from the PSC offices.

Commissioner Lewis pointed out the commission was cutting the program before even receiving APTIM's proposal or modeling. The contractor would have submitted details on its program design May 1.

The third-party, statewide program had been in the works at the PSC since 2010, when the commission retained a consulting firm to draft rules. The PSC finally authorized the program in April 2024.

Logan Burke, of consumer watchdog Alliance for Affordable Energy, said it's illogical for the commission to cancel a statewide program when "residential utility bills are unaffordable for hundreds of thousands of people in our state." Burke pointed out that Louisiana households on average use 46% more electricity than the average American household.

The Louisiana PSC in session April 16 at the Cypress Bend Resort in Many, La. | *Louisiana PSC*

"Why would the commission consider ending the only program that residents and businesses have to manage their bills and keep the lights on?" she asked rhetorically at the meeting. "We are decades behind on addressing energy waste. And so, it doesn't matter how low the rate is if we're just throwing our money out of the cracks around our doors and windows."

Burke said the "rational" thing to do is to finishing standing up the energy efficiency program.

"When will we acknowledge that what we've been doing isn't working?" she said. "What is a more conservative value than eliminating waste?"

"Don't vote to end the program that you barely got started," Lake Charles resident James Hiatt urged. He said the vote seemed emblematic of a "backwoods, back deal, good ol' boys" system. Hiatt added that utilities may have their "thumb on the scale" when it comes to designing programs, suggesting it's not in their interest to help ratepayers lessen usage.

After the meeting, Burke called the vote "a betrayal of the process and the people." Burke said a third-party model could have delivered six times the savings of utilities' programs at about half the cost per kilowatt hour.

The alliance called on the public to contact their commissioners to reverse the vote.

Cleco Power counsel Mark Kleehammer requested that the commission continue allowing utility-led programs, saying they're the most inexpensive means of implementing energy efficiency. Kleehammer estimated about 5% of customers participate in Cleco's in-house energy efficiency program.

Larry Hand, vice president of regulatory and public affairs at Entergy Louisiana, estimated that 5 to 8% of customers participate in the utility's energy efficiency program. Entergy Louisiana uses APTIM to supervise the program.

Louisiana's utility-led program is set to expire at the end of 2025. The current program allows utilities to recoup revenue when sales volume drops due to efficiency measures.

Commissioner Eric Skrmetta suggested it's not fair that most customers are paying for the efficiency efforts of such a small slice of ratepayers.

Skrmetta also said the commission was merely canceling the third-party administration model, not eliminating an efficiency program altogether.

"We are going to have an energy efficiency program, but we've got to look at what we're going to do," he said.

Lewis said the utilities' low participation rates reinforce the need for a standardized, statewide program that's better publicized and understood.

At one point, Commissioner Campbell referred to the motion as "gobbledygook" because it wasn't clear whether the vote also would terminate Louisiana's current utility-led, quick-start program. Commissioners ultimately separated the failed directive into its own motion and amended it to make it clearer that utility-led programs would remain an option as the PSC worked toward a different program.

Campbell repeatedly asked for a month-long stay on the vote to better understand what he was voting for.

Lewis pointedly asked Kleehammer and Hand whether they would recommend a public entities program model nationwide. The question led to a heated exchange over whether the directive motion as written would exclude utility-led efficiency programs from consideration under whichever new paradigm the commission adopts. Other commissioners cut off Lewis' line of questioning.

"I understand the night is late, but this is what we get when we add an agenda item 48 hours before that's extremely important. So, I mean if that's the way we're going to start doing business around here, it's going to be a different game. Because I have issues … and I'm not going to be disrespected just because I have questions," Lewis said of the five-and-a-half-hour meeting. ■

# End Users Push MISO for More Intensive Cost Overrun Evals on Tx Projects

*Continued from page 28*

the IMM should be involved in MISO's transmission planning activities at all. (See *MISO Intent on Answers as to IMM Role in Tx Planning*.)

Stark said another independent third party could evaluate projects. He said MISO could benefit from a set of "third party, disinterested eyes" to make sure MISO gets the best transmission construction outcomes.

Some transmission owner representatives said they weren't sure if dropping the threshold would accomplish much. American Transmission Co.'s Greg Levesque said it seems MISO would spend more money for an independent review just to conclude the projects are necessary and should continue.

ITC's Cynthia Crane said the end-use customers haven't presented a "compelling case" that MISO's current setup is lacking. Crane said it doesn't seem worth upending the roles and responsibilities of state regulators, the IMM and the MISO board.

Stark said there should be more attention on containing costs for MISO transmission projects.

MISO maintains it doesn't need to increase its threshold to evaluate projects. "We think we're at the right spot," MISO's Jeremiah Doner said.

MISO has said it can indicate more clearly to stakeholders when it completes a variance analysis or develops an action plan. But it warned it can't always share confidential project information.

Staff plan to appear before stakeholders at the May cost allocation meeting with some minor edits to its variance analysis. The amendments would focus on MISO's notification and communication commitments to stakeholders when it's conducting a variance analysis.

MISO is conducting one variance analysis now, investigating a 2.5-time jump in costs on one of its long-range transmission projects from its first portfolio. Incumbent developer Northern Indiana Public Service Co.'s 345-kV Morrison Ditch-Reynolds-Burr Oak-Leesburg-Hiple line in Illinois and Indiana now is expected to cost $675 million, up from MISO's estimated $261 million. (See *Cost Overruns on Project in 1st LRTP Prompt MISO Analysis*.)

"We will get to a determination this year," Vice President of System Planning Aubrey Johnson said during March board week, though he didn't have a specific date to expect MISO's conclusion. ■

# DC Circuit Rejects Entergy Attempt to Save MISO Capacity Obligation Rule

*By Amanda Durish Cook*

The D.C. Circuit Court of Appeals has denied Entergy's repeat attempt to revive a 50% minimum capacity obligation rule for MISO's load-serving entities.

The court concluded in an April 15 decision that Entergy lacked standing to request the discarded rule be implemented (*22-1334*). The minimum capacity obligation would have required MISO load-serving entities to demonstrate they obtained at least 50% of the capacity required to serve peak load obligations ahead of and without the assistance of MISO's capacity auctions.

"Even if we were to consider the standing arguments Entergy now belatedly advances, the company has not demonstrated the necessary concrete, imminent and redressable injury," the court decided.

The case dates to MISO's successful bid to create seasonal capacity auctions paired with availability-based resource accreditations.

FERC in 2022 allowed MISO to conduct four seasonal capacity auctions and apply a seasonal accreditation mostly based on a thermal generating unit's past performance during tight system conditions. However, the commission blocked MISO's companion proposal to institute a minimum capacity obligation (ER22-496). (See *FERC Again Rejects MISO Minimum Capacity Obligation*.)

## Why This Matters

MISO's unsuccessful minimum capacity obligation rule, devised in 2021, was struck down a third time, this time by the D.C. Circuit Court of Appeals. Entergy attempted to save it, but the court decided Entergy lacked standing to challenge FERC's prior orders on the rule.

Entergy's Montgomery County Power Station | *McDermott International*

At the time, MISO reasoned that such a rule would keep suppliers from relying too heavily on its capacity auction to serve their customers' needs. The RTO thought it would encourage proactive bilateral contracting and better maintain resource adequacy.

But FERC said MISO did not fully contemplate how the proposal could give its largest utilities too much market power. The commission rejected the rule a second time on rehearing requests from MISO and Entergy's operating companies. Entergy took its challenge to the D.C. Circuit Court. (See *Entergy Seeks Review of FERC's Block on MISO Capacity Obligation*.) The D.C. Circuit said Entergy's opening brief lacked argument, analysis and evidence to support its standing in the case.

"The words 'standing,' 'injury,' 'traceability' and 'redressability' do not appear in the document," the court noted. It said it wasn't until a reply brief that Entergy argued its basis for standing was "apparent." However, the court said, "no reasonable reader … would walk away with a clear understanding of petitioners' precise injuries, the chain of causation and how a decision of this court could redress those harms." The court said it would not "repackage merits arguments as support for a petitioner's standing."

Entergy argued that a refusal of the minimum capacity obligation would lead to future grid risks and free ridership by other MISO utilities on the back of Entergy's investments. The company complained that MISO's auction clearing prices are too low to recover its generation investments. It said requiring utilities to secure at least 50% of their needed capacity outside the auctions would mean it would be able to recoup costs through more contracts with other MISO market participants.

The court disagreed that Entergy's standing was self-evident and said its injuries weren't apparent or traceable. It also didn't accept Entergy's explanation that it omitted its reasoning for standing due to a "clerical oversight." Judges said they saw "no basis for excusing Entergy's noncompliance."

The court concluded Entergy failed to submit any proof outlining how it would be harmed financially by heightened reliability risks under the status quo and, conversely, spared from them had FERC accepted the minimum capacity obligation rule. The court said even descriptions of the reliability crisis weren't uniform in the case record, with some sections referencing an "immediate concern" while other parts called it a nonissue and said it "could result" in an "impact on reliability … over the next decade."

Lastly, the D.C. Circuit said a complex sequence of hypothetical events must unfold before Entergy's claims of injury from future free ridership make sense. It said other utilities would have to turn to Entergy for bilateral contracts and negotiate deals containing higher prices to compensate Entergy for its capital expenses.

"Entergy wholly fails to articulate how this chain of events would occur," the court said, also noting that Entergy's only evidence of more future contracts was a citation to the Independent Market Monitor's concern that Entergy, as a pivotal MISO supplier, would be able to use a minimum capacity obligation to charge "anticompetitive" prices to other utilities.

"Implicitly, then, Entergy's causal chain rests on an exercise of market power — a fact which Entergy repeatedly and strenuously rejects. Entergy cannot credit the market power objections for standing purposes but disavow them on the merits," the D.C. Circuit said. ■

# MISO Forming 4th Tx Planning Scenario Based on Supply Chain Barriers

## Trump Tariffs Adding Increased Uncertainty

*By Amanda Durish Cook*

MISO is on its way to installing a fourth, 20-year future to inform transmission planning in case supply chains remain unsteady.

During an April 14 teleconference to develop MISO's first new planning future in six years, RTO staff said they are approximating annual build limits on new capacity. They also said the Trump administration's tariff decisions could introduce further instability that makes the fourth scenario more difficult to pin down.

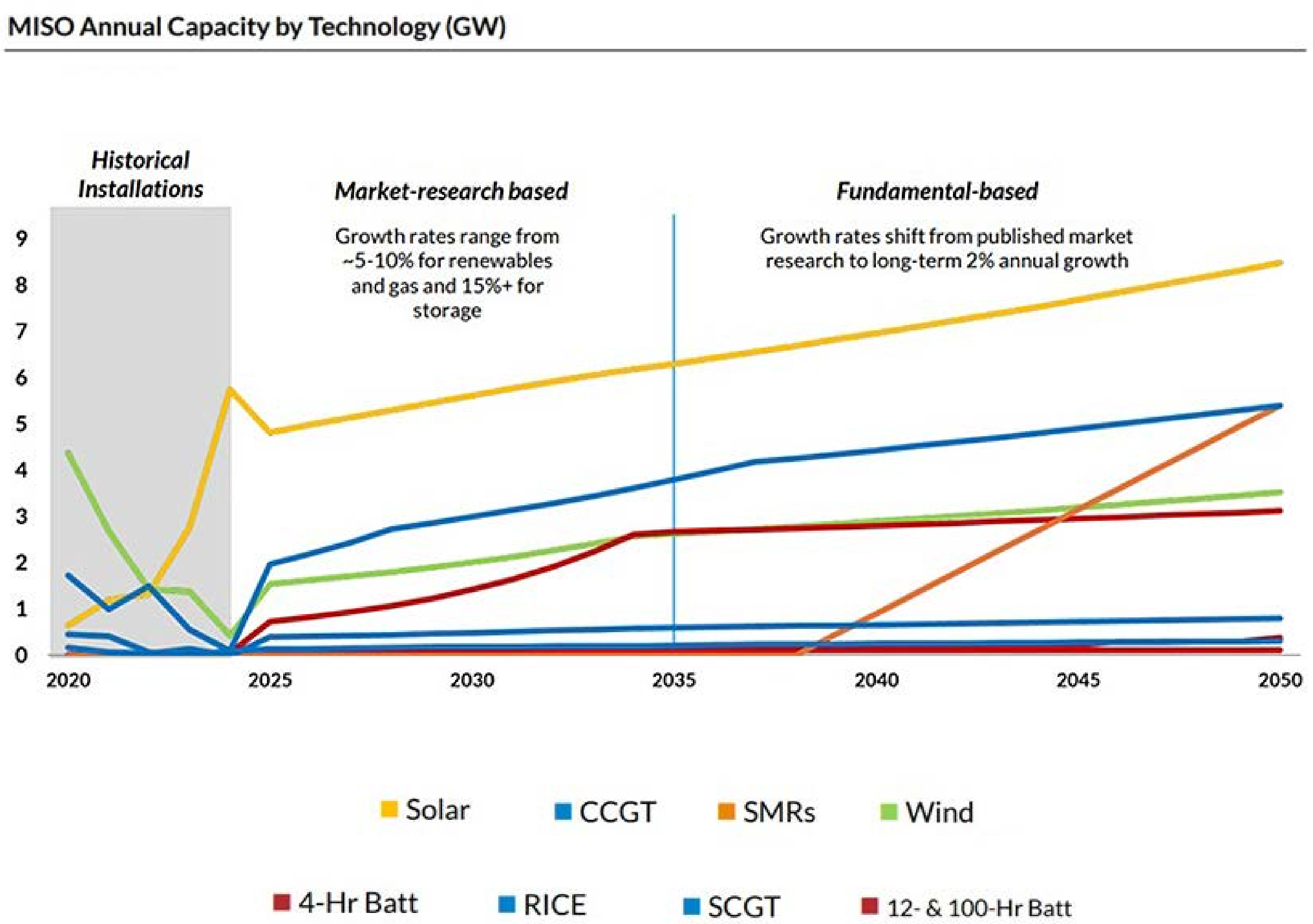
MISO Senior Manager of Policy and Regulatory Planning RaeLynn Asah said the RTO sees "fairly impactful constraints" on all types of generation into the future.

The RTO is revising its trio of 20-year futures scenarios that it relies on to plan transmission. It has said it must incorporate aggressive load growth and create a fourth scenario specifically designed to study the footprint if fraught supply chains continue to impede new generation construction. (See *MISO Aims for 4 New Tx Planning Futures in 9 Months* and *MISO Fields Divergent Calls for Stronger South Planning, IRA Reversal in Tx Futures*.)

MISO has tentatively called the new scenario its "Supply Shift" future. It would contemplate continued "supply frictions"

### What's Next

MISO will spend most of the year plotting a fourth transmission planning future that doesn't see much improvement in supply chains. It would be used to plan long-range transmission alongside its existing 'Lower Load Growth,' 'Stated Policy' and 'Higher Load Growth' scenarios.




MISO's estimated capacity limits under its new, fourth future | *MISO* that limit the pace of capacity expansion. MISO envisions that load growth might have to be managed through keeping existing generation online and establishing more demand-side resources.

MISO created its current trio of futures in 2019 and last updated them in 2022. A decade ago, the grid operator used as many as 10 different futures to plan long-range transmission.

DL Oates, MISO executive director of markets and grid research, said the RTO is calculating annual capacity build limits by resource type for its fourth future through an assessment of U.S. manufacturing capability, labor constraints and tariff impacts. It multiplied the limits it found by its share of U.S. installed capacity.

"Preliminary results reveal some tension between member-submitted planned units and projected regional supply constraints," Director of Economic and Policy Planning Christina Drake told stakeholders.

MISO acknowledged that President Donald Trump's tariffs could add hurdles for generation and said it wants to adopt a wait-and-see approach on whether they have a material impact on generation expansion.

"What we would like to do is let this information settle," Drake said.

Oates said MISO put its initial assessment together when the country-specific tariff rates were "volatile."

"This is a shifting situation with these tariffs, so you'll have to give us a little leeway to figure out what makes the most sense," Oates said.

MISO does not plan to apply an age-based retirements assumption on its existing fleet for the supply-squeezed future. The RTO would assume some retirement delay announcements.

The Sustainable FERC Project's Natalie McIntire said it did not seem realistic for MISO to forgo any age-based retirements. She asked it to maintain the same retirement assumptions it applies to the fleet in its three other futures.

"It doesn't make sense to me to hardwire it into the model," McIntire said.

Oates said that if members can't build enough new generation, they may be forced to put off retirements.

"Our working hypothesis is that we're not going to be able to balance generation and load," Drake said. She added that MISO will "keep an eye on" whether age-based retirements might make sense in the scenario.

Even with retirement delays, MISO envisions the future would hold a minimum of 60% in emission reductions from 2005 levels, the same as its middle-of-the-road "Stated Policy" future. That would hold unless MISO finds that throttled build rates stand in the way of reducing greenhouse gases. The RTO's most dynamic, "Higher Load Growth" future estimates a minimum 80% reduction from 2005 emissions levels.

MISO engineer Brad Decker said an enduring labor force pinch can "be a drag" on capacity expansion, especially to stand up labor-intensive solar farms.

Decker said MISO is contemplating tariffs on solar components anywhere from 17 to 37%, not the 145% the Trump administration has publicized.

"China doesn't really export a lot of solar to the United States. They send materials through intermediate countries," he explained, adding that MISO would factor in those intermediate countries' reciprocal tariffs.

Despite wind component sourcing being largely U.S.-based, recent closures of plants that produce blades have shrunk manufacturing capability, Decker said, "posing a risk to scaling wind deployment until domestic production is expanded."

Decker said small modular reactors likely won't be a commercial option for at least 10 years.

"A lot of things have to happen between now and then to make these viable," Decker said. For example, he said, the nuclear industry needs to stand up a market for high-assay low-enriched uranium to fuel the new type of plants. Decker said SMR projects and demonstrations have lurched in a "stop-and-start trajectory, marked by cost overruns and project cancellations due to undersubscribed offtake agreements."

The Union of Concerned Scientists' Sam Gomberg said he worried that MISO was being too "rosy" on SMR emergence within a decade and that its estimates would be biased if it relied on the "shiny FAQ sheets" from nuclear developers. He said the nuclear industry has a poor track record in meeting goals and announcements when bringing new capacity online.

Decker said there is a reluctance among gas turbine manufacturers to ramp up production because they remember overcommitting production in the early 2000s. Oates noted growing order backups for General Electric, Siemens, Mitsubishi and other suppliers because of surging, AI-driven demand for firm generation.

The supply crunch future would also consider a small-scale emergence of 12-hour, long-duration battery storage from advanced lithium-ion batteries and up to 100 hours of stored energy from iron-air batteries.

MISO said it won't factor in other emerging technologies like extended-duration batteries that can last more than 100 hours, green hydrogen, combined-cycle plants with carbon capture and sequestration, and new geothermal technologies. Those are likely too far down the road to be considered in this round of futures, staff said.

The RTO is taking stakeholders' reactions to its resource assumptions in its fourth future through April 28. It will refine the futures through the fall before using them in 2026 to plan more long-range transmission. ■

## National/Federal news from our other channels

*FERC Upholds Preliminary Permit for Pumped Hydro Concept*

NetZero Insider

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

# NYISO Cancels 2033 Reliability Need for NYC

NYISO ended the Operating Committee's meeting April 17 with a surprise announcement: The ISO is no longer concerned about a violation of reliability criteria in New York City in 2033 and has canceled its search for a solution.

Zack Smith, senior vice president of system and resource planning, told the committee that updates to assumptions used in demand forecasting and demographic trends had eliminated the need over the 10-year horizon. Margins are still shrinking because of plant retirements, he said, but not enough to trigger the reliability need.

## Why This Matters

The RNA published last year would have kicked off a solicitation process for resolving a capacity shortfall in New York City.

NYISO had officially made the declaration in November 2024 as part of its 2024 Reliability Needs Assessment. It triggered a process in which the ISO solicits solutions, including transmission-based from the local transmission owners, and generation and demand response from market participants. (See *NYISO Publishes Final RNA Showing Reliability Need for NYC*.)

Kevin Lang, a partner with Couch White who represents the city at the ISO, asked if the forecast included the completion of Empire Wind 1, an offshore wind project that just the day before was ordered to halt construction by the Trump administration. (See related story, *Feds Move to Halt Construction of Empire Wind 1*.)

Smith affirmed that it was and that NYISO was confident that even a "significant delay" would not have changed the finding. And even if the project ultimately does not go forward, it would not significantly impact the ISO's reliability margins, he said.

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There will be a full discussion of the findings at the Electric System Planning Working Group's next meeting, currently scheduled for May 6, Smith said. ■

*— Vincent Gabrielle*

# NYISO Announces 2 New Board Members

*By Vincent Gabrielle*

NYISO has appointed two new members to its Board of Directors, Chair Joseph Oates announced at the board's meeting with the Management Committee on April 15.

Heather Rivard will join the board in July following her retirement from Southern California Edison, where she has served as senior vice president of transmission and distribution since September 2021. Prior to that she worked for DTE Energy for 28 years, climbing the ladder there until she was senior vice president of electric distribution.

Steve Doyon, who joined the board effective that day, was most recently the president and CEO of Onward Energy, an independent power producer in Denver that operates and manages over 6 GW of wind, solar and gas generation. He has worked in the energy industry for nearly 40 years at several companies, including DTE, Cogentrix Energy, AES and Terra-Gen Power.

| NYISO

"The board is very excited to have the two of them joining us," Oates said. "And we look forward to engaging with them on the evolving energy issues we face here in New York."

Oates and Director Gizman Abbas were both reelected to the board, while Director David Hill was elected vice chair. Director Mark Lynch will chair the board's Audit and Compliance Committee for another year, while Director Michael Crowe was assigned the chair of the Commerce and Compensation Committee. Abbas was made chair of the MC's Liaison Subcommittee. Sally Talberg will chair the Reliability and Markets Committee.

Oates also briefly acknowledged that FERC had approved the ISO's proposal for collecting import duties on electricity, if the Trump administration determines that the president's tariffs on Canada apply to it. (See *FERC Authorizes NYISO, ISO-NE to Collect Tariffs on Electricity*.)

A stakeholder asked the ISO whether there was any financial impact from the tariff levied by Ontario on its electricity exports for the short period it was in place and whether it factored into FERC's ruling. Oates said he could not say.

"We sort of just found out this morning that FERC approved our tariff filing," Oates said. "We'll take that back and at the next appropriate working group or committee of the ISO, we'll report back." ■

# NJ Gov. Urges FERC to Investigate PJM; Christie and Phillips Defend PJM

## Christie Commends PJM staff, Says Criticism from Politicians is 'Misplaced'

*By Hugh R. Morley*

### Why This Matters

New Jersey, Maryland and other mid-Atlantic states worry about the rapidly increasing cost of electricity, and the region's ability to generate enough power in the future. They also criticize a lack of transparency from PJM.

New Jersey Gov. Phil Murphy (D) *is asking* FERC to investigate "potential market manipulations" in the PJM Base Residual Auction (BRA) in July 2024 that state officials say contributed to a 20% hike in electricity rates in New Jersey.

Murphy, in *a letter* to FERC commissioners, said he had "deep concerns about the PJM cost crisis." He said he believes the "exorbitant price increases" in PJM's July auction "may have been subject to market manipulation."

FERC Chairman Mark Christie defended PJM staff *in comments* at the monthly FERC meeting April 17.

"A lot of this criticism that I've been seeing in the media, directed at PJM and its management, and blaming them for everything that is wrong with the PJM capacity market, is in many ways misplaced," he said. "And a lot of it is because of state policies that have sort of come to a head just recently."

Christie particularly cited the work of outgoing PJM CEO Manu Asthana and other PJM executives. (See *PJM CEO Manu Asthana Announces Year-end Resignation*.)

"Manu had the unlucky job of coming in when a lot of factors that were put in play 20 years ago sort of started to come to a head," Christie said. "These factors, such as the big increase in load that we've been seeing in the last few years, the loss of resources has been ongoing for years, and all this sort of came to a head. But he has done, I think, an outstanding job. I've always found him to be very, very straightforward and open in dealing with me."

FERC Commissioner Willie Phillips | *FERC*

Commissioner Willie Phillips agreed with Christie. "I want to echo the comments you made about Manu and PJM leadership. I think what you said was spot on and very well said."

Asked whether FERC would launch an investigation, Christie said he had to be careful about commenting because the commission has pending cases dealing with the high prices from the last capacity auction. But he noted he has been a skeptic/critic of the capacity market construct since it first was launched.

"I think that a lot of the problems that PJM is facing today are the result of trends that have been going on for 21 years," Christie said. "And again, I'm a fact-witness to that. I've been there, and I think a lot of decisions were made years ago that are now showing up and causing problems for a lot of the states that are complaining the most. One of the biggest problems, I think, was 20 some years ago. They made a decision to use the PJM capacity market as their mandatory sole source of resource advocacy, and so that put them at the mercy of the PJM capacity market."

Many of the member states have pointed the finger solely at PJM for those problems, but Christie argued some of their state policies are to blame as well. FERC is holding a two-day technical conference in June to look at resource adequacy, where the issues will be discussed.

Gov. Murphy's letter urged FERC to "determine the extent to which any such manipulation may have resulted in higher capacity auction prices that are being passed on to retail electricity customers in the PJM market, particularly in New Jersey."

"I believe that billions of dollars in excessive costs for [consumers] are the direct result of fundamental flaws in PJM's capacity market and were foreseeable and

*Continued on page 37*

# Christie Blasts PJM Pursuit of Transource Market Efficiency Project

## FERC Order Dismisses PJM Waiver Request as Moot

*By Devin Leith-Yessian*

FERC Chair Mark Christie on April 17 criticized PJM for continuing to consider proceeding with Transource Energy's Independence Energy Connection (IEC) transmission project years after Pennsylvania regulators denied it a certificate of public convenience and need.

Christie's comments came in his concurrence with a commission order dismissing as moot a PJM request to waive its deadline to complete an annual reevaluation of the project (*ER25-612*).

Should Transource "and PJM succeed in persuading a federal court that the mere selection of a transmission project planned by PJM acts to preempt the states' CPCN laws — a position vigorously opposed by all the states as expressed by the National Association of Regulatory Utility Commissioners — such a ruling will likely be a Pyrrhic victory of monumental proportions," Christie wrote. "Such an outcome will tell the states, which retain the authority under their inherent police powers to decide whether to allow their utilities to join, not join or leave RTOs, that the rules of the game have been changed radically after the fact — without the states' agreement and, as the history recounted herein shows, contrary to earlier pledges to respect state laws. So perhaps state perspectives on RTO membership for their utilities should be reconsidered."

PJM filed the waiver request in November 2024 to ask the commission to allow it to complete its annual reevaluation of the project in the third quarter of 2025, stating that its market efficiency modeling could not be complete until reliability violations had been resolved in the 2024 Regional Transmission Expansion Plan (RTEP).

In December 2023, a federal court ruled that the Pennsylvania Public Utility Commission had violated the U.S. Constitution, finding that the denial was based on economic protectionism rather than siting. The court said PJM must complete a new cost-benefit analysis before the project can proceed. (See *Federal Court Rules in Favor of Transource Congestion Project in PJM*.)

FERC Chair Mark Christie | *FERC*

### Why This Matters

FERC Chair Mark Christie's remarks add to a recent chorus of regulator criticism of PJM, which includes threatening to reconsider their utilities' RTO membership: "So perhaps state perspectives on RTO membership for their utilities should be reconsidered," the former Virginia regulator wrote.

In the absence of a FERC order Dec. 20, 2024 — PJM's requested effective date for the waiver request — the RTO proceeded with completing the reevaluation with the same modeling used in the 2023 evaluation, resulting in the same benefit-to-cost ratio of 0.81 as the earlier analysis. That ratio was 1.09 when sunk costs were excluded. In a *presentation* to the Transmission Expansion Advisory Committee in January, PJM said that using older data could mask impacts affecting the project.

"Significant impacts may be presently and temporarily masked by reliability and other issues which are being addressed by RTEP projects that are expected to be approved in first quarter of 2025," PJM said.

Comments opposing the waiver request contested the benefits of the project and argued that PJM had not followed its tariff requirements. They argued PJM staff should have recommended that its Board of Managers cancel the project or have considered it canceled when the PUC denied the CPCN for construction.

The commission ruled that PJM's completion of the reevaluation with "the presently available model" rendered the request moot.

First approved by the PJM board in August 2016, the project includes two 230-kV lines across the border between Pennsylvania and Maryland. It has been suspended since September 2021 after the PUC's denial. The Maryland Public Service Commission approved the segments of the project running through its state in June 2020 and has issued repeated extensions on deadlines for construction to start as the litigation proceeded.

### Christie Argues Ignoring CPCN Denial Would Undermine State Authority

In his concurrence, Christie wrote that it is "remarkable" that the issue was brought before the commission four years after the PUC denied the CPCN for the project.

The idea that PJM planning supersedes state siting authority could undermine states' ability to require utilities to obtain CPCNs for any projects if they remain RTO members, Christie argued.

"The claim that, because PJM and other RTOs are federally regulated, the inclusion of a PJM-planned transmission project in PJM's RTEP effectively preempts a state's inherent police power authority to approve that and other utility projects within its borders is, frankly, outrageous. FERC Order No. 1000, which set up the entire regional planning regime under which PJM and other RTOs now operate, said the opposite," he wrote.

He linked the possible impact to state jurisdiction to his longstanding opposition to incentives awarded to utilities that join RTOs, saying that awarding developers construction work in progress incentives for projects included in PJM's RTEP, but which are suspended or have been denied CPCNs, inflates consumer rates. He compared the continuation of the IEC project to PJM's abandoned Potomac-Appalachian Transmission Highline project, which he said cost consumers a quarter billion dollars with no construction ever commencing. (See *Christie Blasts FERC Transmission Incentives in PATH, Brandon Shores Orders*.)

"As transmission costs rise rapidly in PJM, as well as in all other RTOs, it is past time for this commission to fulfill its duty to ensure 'just and reasonable rates' under the Federal Power Act by protecting consumers from the costs of FERC's own policies that are inflating those rapidly rising transmission costs," Christie wrote. "And to be more specific, as the debate continues over whether to give transmission developers/owners a perpetual [return on equity] adder for joining an RTO, the history recited herein is extremely relevant. History matters." ■

# NJ Gov. Urges FERC to Investigate PJM; Christie and Phillips Defend PJM

*Continued from page 35*

preventable," the letter said.

In response, PJM released a statement that said the organization "has not seen evidence that supports a finding of market manipulation in the 2025/26 capacity auction, but we take such allegations very seriously." FERC's Office of Enforcement "is the right place to address such a concern, and PJM will follow any directives we receive from FERC," the statement said.

"New Jersey has insufficient generation in-state to meet its needs, and has to make up this difference through imports," said the statement, released by spokesman Jeffrey Shields. "A seven-year-long effort by New Jersey to fill this gap with offshore wind has failed to deliver any results whatsoever, and consumers are now paying the price for this failure."

Murphy's statement marks a new stage in the friction between PJM and New Jersey and other states over the rapidly increasing cost of electricity and the region's ability to generate enough power in the future.

New Jersey and Maryland officials on April 16 attended a press conference for the release of a report by Evergreen Collaborative, a national environmental group that promotes solutions to climate change. The report predicted a 60% hike in electricity rates unless PJM takes steps to reform the process by which new clean energy sources are added. (See related story *NJ, Md. Officials Target PJM After Critical Report*.)

Pennsylvania in January filed a complaint with FERC about PJM, which resulted in the RTO's agreement to cap future auctions' capacity prices. (See *PJM, Shapiro Reach Agreement on Capacity Price Cap and Floor*.)

New Jersey's draft master plan, released March 13, predicts demand for electricity will increase by 66% by 2050, and state officials are concerned about how they will meet that need. (See *NJ Releases Electrification-focused Energy Master Plan*.)

PJM says the expected shortfall in power is in part due to the slow pace of new energy sources coming online compared to the far faster pace at which older generating sources — mainly fossil-fueled sources — are going offline, often in line with state policies. In addition, PJM says the region can expect an influx of high-energy-using entities, especially artificial intelligence data centers.

New Jersey, and other states, say PJM has failed to plan for the surge and the problem is exacerbated by the slow pace at which the agency approves new energy sources, especially renewable energy sources. ■

# NJ, Md. Officials Target PJM After Critical Report

## Environmental Group's Report Calls for More Queue Reform

By Hugh R. Morley

### Why This Matters

New Jersey and Maryland officials are so frustrated with PJM because of rate increases and the slow interconnection queue that leaving PJM altogether is a possibility.

A D.C.-based environmental group argues electricity prices will rise by 60% in the PJM region if the RTO does not reform its permitting system to allow more clean energy.

The Evergreen Collaborative and consultant Synapse Energy Economics of Massachusetts released a report April 15 that predicts a 60% hike in residential bills will be reached by 2036 to 2040 if PJM continues on its current path. Residential rates could decline by 7% over the same period if PJM adopts interconnection reforms, such as accelerating the timeline by which new clean energy sources are approved, providing cheaper energy, *the report claims*.

"With swift action to resolve the interconnection queue, it can reduce electricity prices while bringing on new resources to power new demand and enable economic growth," the report says. Evergreen Collaborative, founded in 2020 by supporters and staffers of former Washington state Gov. Jay Inslee (D), aims to create an "all-out national mobilization to defeat the climate crisis and create millions of jobs in a clean energy economy."

The report drew vigorous support from Maryland and New Jersey officials. New Jersey ratepayers will experience a 20% hike in the average bill June 1 due to the basic services generation auction in February.

State officials say that auction was shaped by record-high prices in the PJM capacity auction in July 2024. An imbalance of supply and demand was the result of several factors: a surge in expected demand due to AI data center developments; limited supply due to the RTO's slow rate of approval for new clean energy sources; and the faster pace at which fossil fueled generators are closing. (See *PJM Capacity Prices Spike 10-fold in 2025/26 Auction*.)

The sudden price hike and expected supply shortfall have triggered heated words from New Jersey officials, who say PJM failed to anticipate the demand increase. The RTO says the shift was so sudden it couldn't have been anticipated. (See *NJ Lawmakers Sound Energy Supply Alarm*.)

PJM, responding to the Evergreen report, said it has taken "multiple actions, working with stakeholders, to make as much generation capacity available to the grid as quickly as possible." (See *PJM Board Initiates Fast-track Process to Address Reliability*.)

"PJM has already established an expedited process, which recently cleared 18 GW to finalize agreements to interconnect to the grid," the RTO said in a statement released by spokesperson Jeffrey Shields. "We have about 66 GW of active projects that we will complete in 2025 and 2026 as part of the reform transition period."

### Leaving PJM

Representatives of New Jersey and Maryland, who took part in a press conference marking the release of the report, titled "Tackling the PJM Electricity Cost Crisis," said the RTO needs to do a lot more, or see participating states look for alternative energy sources.

"We're at a fork in a road. We can't afford for PJM to continue down the same path," said Eric Miller, executive director of New Jersey Gov. Phil Murphy's Office of Climate Action and the Green Economy. "My office is calling on PJM to clear the queue as quickly as possible, adopt reforms that make interconnection timelines more predictable and leverage next generation grid-enhancing technologies."

Paul G. Pinsky, director of the Maryland Energy Administration, called PJM "one of the largest obstacles" to the state's efforts to reach 100% clean energy and "reduce soaring energy bills."

"I'm not here to say we're going to pull out of PJM," Pinsky said. "PJM is an RTO of importance. But it's trailing a lot of the other organizations around the country in how quickly they can bring online new energy, and, in our belief, clean energy. So we want to bring as much pressure to bear."

New Jersey state Sen. Andrew Zwicker (D) said the reality laid out in the report is that "PJM is sitting on hundreds upon hundreds of renewable and affordable energy projects that, in the end, would lower the bill for New Jersey families and families across the PJM area."

Asked by a reporter if he considers the situation so bad that New Jersey and Maryland should consider leaving the RTO, Zwicker said "everything's on the table right now."

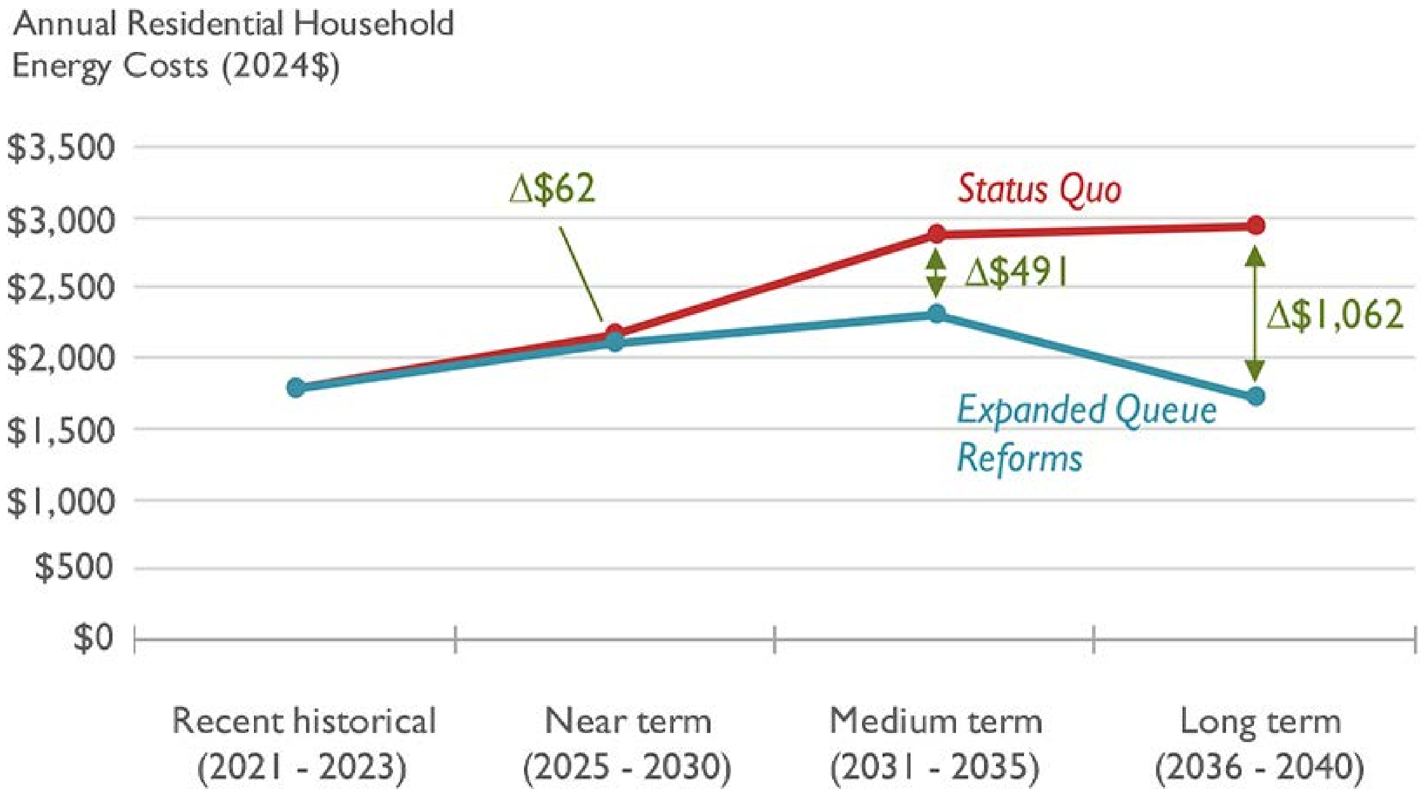
"New Jersey doesn't plan to be rash about this, and we have to do a very careful analysis of what the impact would be on New Jersey ratepayers," he said. "But it has to be part of the discussion at this point, that's for certain."

### Rate Counsel Complaint

New Jersey officials say the high cost of power from PJM stemmed in part from "flawed" modeling by the RTO in the run-up to the July 2024 auction. There was a failure to properly include all the clean capacity expected to come online, they say, leading bidders to think there was less new capacity in the pipeline than in reality.

The New Jersey Division of Rate Counsel and the Maryland Office of People's Counsel on April 14 filed a complaint with FERC, arguing PJM's auction produced "demonstrably unjust and unreasonable outcomes that the commission must now remedy."

The complaint alleged that "defective market rules either ignored or allowed market participants to withhold thousands of megawatts of existing capacity, while interconnection delays, a compressed auction forward period, and other entry barriers prevented the participation of new supply capable of disciplining incumbent market power."




Annual residential household energy costs, average in PJM | *Synapse Energy Economics*

The complaint demands that PJM redo the 2024 capacity auction, changing the rates for energy not yet delivered and fixing the defects in the process for the next auction. "What is at stake is an enormous and unlawful transfer of wealth from customers to owners of capacity resources: at least $4 [billion to $]5 billion in excess charges resulting from the subset of artificial supply constraints" in the auction, the complaint argues.

## System Reforms

Looking to the future, the Evergreen Collaborative report calculates the average residential household costs under the "status quo," with the RTO operating as at present, and with the queue reforms suggested in the report implemented. The report does so for seven states and Washington, D.C.

Under these scenarios, the average annual New Jersey residential bill would be $2,003 if the status quo continues, falling to $1,598 if the suggested reforms are adopted. The average Maryland bill would be $2,358 in the status quo and $1,813 with the reforms, according to the report. The average residential household cost across PJM would be just under $3,000 in the status quo over the period, and $1,062 less with reform implementation, the report says.

The reforms suggested by Evergreen include:

- Requiring PJM to approve projects within a 150-day timeline. A Synapse Energy Economics consultant said this timeline is required by FERC under its Order 2023. But PJM is asking FERC for approval for a timeline of one to two years.
- Implementing the first-ready, first-served cluster study approach on time for the regular-order queue.
- Using realistic modeling assumptions for energy storage behavior rather than assuming energy storage will charge during peak periods and require associated transmission upgrades.
- Studying grid enhancing technologies as part of transmission planning.
- Making it easier for developers to use interconnection agreements held by existing power plants and continue to use them after the existing plants retire.

PJM, noting that it began "significant interconnection process reform in July 2023," said it since has "relieved the interconnection backlog by 60% and placed more than 6 GW of new generation into service."

PJM suggested the high auction bids confirmed its analysis that "the supply/demand balance has been tightening." And the RTO added that it "will fully comply with Order 2023 but [has] also petitioned FERC to allow [it] to fit the order to PJM's already approved and implemented rules." ■

# PJM Stakeholders Discuss How to Increase Storage Development

*By Devin Leith-Yessian*

A panel of storage developers, regulators and RTO representatives discussed the roadblocks holding back the growth of battery storage installations in PJM during a meeting of the RTO's Public Interest and Environmental Organization User Group.

Claire Lang-Ree, an advocate for the Natural Resources Defense Council and moderator of the April 16 panel, said storage presents an opportunity to work toward state environmental goals while also providing capacity at a time when PJM is signaling a possible shortfall in 2030. While batteries share a similar effective load carrying capability rating to gas generation, she said, they aren't affected by a shortage of turbines and have one of the fastest development timelines of any resource type.

"Really if we need resources to come online and provide capacity quickly, battery storage is uniquely positioned to do that," she said.

She said storage also could allow generators to deactivate without requiring reliability-must-run (RMR) agreements, which are triggered when reliability violations are identified should a resource go out of service. PJM traditionally has resolved those needs with transmission projects, which consumer advocates and environmentalists have said take years to complete, sharply increasing rates while the RMR agreement is in effect and keeping fossil generation online longer.

## Increasing Capacity Prices Create New Market Potential for Storage

Convergent Energy COO Don Jenkins said high capacity prices in PJM's 2024/25 Base Residual Auction have helped make batteries more economical. But the core challenge continues to be the amount of time it takes to get construction started.

"Where we really run into the biggest roadblocks or delays is that permitting or interconnection process," he said.

CAISO Storage Sector Manager Sergio Dueñas Melendez said long-term

Shutterstock

bilateral capacity contracts also can give investors the stability needed to invest in storage development, which has helped fuel the growth of batteries in California. The state directed utilities to develop storage procurement targets and worked with the public utilities commission, CAISO and utilities to resolve roadblocks to getting batteries online.

While the approach in CAISO is simplified by its structure as a one-state grid operator, Melendez said there are several PJM members with their own climate goals, who can develop their own procurement plans or coordinate with each other.

Grant Glazer, MN8 Energy senior manager of regulatory and market affairs, said the uncertainty of future capacity prices can make it difficult to underwrite storage as projects increasingly look to target revenues beyond PJM's ancillary service markets.

## New Market Products Could Capture Unrecognized Storage Capabilities

Much of the panel centered around whether new market designs or products are needed to reflect the capabilities storage has to offer.

PJM Chief Economist Walter Graf said batteries offer valuable flexibility when ramping capability is needed, but the only lever dispatchers often have is out-of-market commitments. When uplift is paid to resources for those services, all other flexible resources — like batteries or demand response — that also provide those services are undercompensated for services they provide.

Glazer said MN8's top market design priorities are allowing storage resources to include opportunity costs in their energy bids, a seasonal capacity market and new ancillary service products — namely uncertainty and ramping reserves.

When storage resources are mitigated to their cost-based offers, Glazer said they cannot include opportunity costs and therefore lose the ability to manage their state of charge. This can cause a storage resource to discharge once it becomes profitable, even if prices are expected to be higher later in the day. It also can expose them to potential capacity performance (CP) penalties if they discharge before anticipated periods of high-strain conditions begin and a performance assessment interval is initiated. He argued that both forgone energy costs and CP risk should be allowed in energy market opportunity costs.

Jenkins said this was on display in ERCOT on April 7, when batteries were deployed earlier in the day only for there to be a spike in prices later in the day associated with thermal generators going offline. Had there been a mechanism for price signals to storage and dispatchers to recognize there would be a jump in demand in the near future, he said the dispatch of those resources could be better optimized.

Melendez said CAISO has "mitigated the challenges of mitigation" by introducing a default energy bid that includes opportunity costs which considers the highest price of the day-ahead market, the duration of the resource and the potential revenues a battery could miss out on.

The hold exceptional dispatch instruction also allows CAISO to tell a storage resource to reach a certain state of charge and maintain that for future needs, including opportunity costs in the process. It has proved useful, but the growing number of resources is cumbersome for operators to manage, leading staff to explore how it can be streamlined. ■

# PJM MRC/MC Preview

Below is a summary of the agenda items scheduled to be brought to a vote at the PJM Markets and Reliability Committee and Members Committee meetings. Each item is listed by agenda number, description and projected time of discussion, followed by a summary of the issue and links to prior coverage in *RTO Insider.*

*RTO Insider* will be covering the discussions and votes. See next week's newsletter for a full report.

## Markets and Reliability Committee

### Consent Agenda (9:05-9:10)

B. Endorse proposed *revisions* to Manual 11: Energy & Ancillary Services Market Operations resulting from the document's periodic review. The changes include updating hyperlinks, correcting grammar, and specifying that data centers and crypto mining fall into business segment load. (See "Committee Endorses Manual 11 Periodic Review," *PJM MIC Briefs: April 2, 2025*.)

C. Endorse proposed *revisions* to Manual 37: Reliability Coordination drafted through its periodic review. The changes are focused on administrative updates and clarifying the default baseline voltage limits.

### Endorsements (9:10-9:30)

1. **Black Start Base Formula Rate (9:10-9:30)**

PJM's Glen Boyle will *present* a proposal to rework how resources providing black start service are compensated. The new formula would be based on a five-year average of the RTO-wide net cost of new entry (CONE) for the 2025/26 delivery year, which would be adjusted using the Handy Whitman index in following years. PJM has argued the change will reduce the volatility of black start compensation and prevent existing providers from ceasing their participation. (See "PJM Presents 1st Read of Proposal to Rework Black Start Compensation," *PJM MRC/MC Briefs: March 19, 2025*.)

The committee will consider endorsing the proposed solution and corresponding tariff revisions. Same-day endorsement will be sought at the Members Committee.

Issue Tracking: *Black Start Base Formula Rate*

## Members Committee

### Endorsements (10:50-11:05)

1. **Black Start Base Formula Rate (10:50-11:05)**

If endorsed by the MRC, PJM's Glen Boyle will *present* the proposal to rework black start compensation to the Members Committee.

The committee will consider endorsing the proposed solution and corresponding tariff revisions.

Issue Tracking: *Black Start Base Formula Rate* ■

*— Devin Leith-Yessian*

# SEEM Opponents Urge FERC for Clarification

## PIOs Call Out 'Confusion' of Comparability Standard

*By Holden Mann*

The Sierra Club, Southern Alliance for Clean Energy and 11 other opponents of the Southeast Energy Exchange Market (SEEM) called on FERC to either clarify its March 14 order to update the market's agreement or allow a rehearing of what they described as a novel legal theory put forward by the commission (*ER21-1111-006, et al.*).

The April 14 requests by the opponents, jointly filing as the ad hoc Public Interest Organizations (PIOs), arrived the same day as a response filed by SEEM members to FERC's order. (See *SEEM Members File Market Agreement Update*.)

That response was an update to the SEEM agreement confirming that utilities may participate in the market via pseudo-ties, addressing a concern of the D.C. Circuit Court of Appeals about the agreement's requirement that participants have a source or sink physically located within the market's territory.

The PIOs' filing concerns a different part of the March 14 order, which FERC issued following briefings from supporters and opponents of SEEM. In the order, FERC affirmed its earlier decision that SEEM's open access transmission tariff is "consistent with or superior to the *pro forma* OATT," justifying the assessment on the basis of the commission's comparability standard, which FERC said "requires that comparable service be provided to comparable customers."

This description of the comparability standard is the crux of the PIOs' filing, which accused FERC of inventing a new definition by adding the term "comparable customers." The PIOs noted that when FERC initially articulated the standard in 1994, it said that an OATT "should offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions, as the transmission provider's uses of its system." At no point since then has the commission used the "comparable customers" language, the PIOs said.

### Why This Matters

SEEM opponents warned that FERC's order used language that contradicted the commission's previous arguments and could create confusion in the future.

D.C. Circuit Court of Appeals | *D.C. Circuit Court of Appeals*

"Nothing in the March 14 order indicates that the commission intended to modify its precedent regarding" the comparability standard or the alternative undue discrimination analysis of "whether utilities and their native load customers are similarly situated to third parties," the PIOs continued.

Further, they argued that the same paragraph seems to switch between the two frameworks, finding that "entities located outside the SEEM footprint are not similarly situated to [those within], which justifies SEEM's requirement that the former utilize a pseudo-tie to participate." The discrepancy indicates that FERC's order "did not intend to apply the comparability standard at all," they said.

To address this "potential confusion," the PIOs said FERC should clarify the March 14 order. They suggested doing so by removing the sentence that mentions the comparability standard, which would confirm that only the undue discrimination analysis should be applied.

If the commission did intend to apply the comparability standard, it should allow a limited rehearing of the relevant sentence and "modify the discussion to retract this unexplained and unjustified departure from its practice and precedent," the PIOs argued. Such action is needed to address what they called FERC's arbitrary and capricious redefinition of the standard. ■

# New ERAS for SPP: Stakeholders Approve RA Studies

## Process Designed to Help LREs Meet Their Requirements

*By Tom Kleckner*


Empire District's Aaron Doll explains his company's position on the ERAS proposal. | © *RTO Insider*

HOUSTON — SPP stakeholders debated a contentious tariff revision request that creates a one-time study outside the grid operator's normal planning process during their quarterly Markets and Operations Policy Committee meeting. They took a break and then continued the debate.

Eventually, MOPC passed a series of votes April 15 that sends the expedited resource adequacy study (ERAS) proposal (*RR668*) to the SPP board and its Regional State Committee, composed of state regulators in the RTO's footprint, for final approval.

"I think for most of us there, we had some fun elements and getting some clarity around motions," MOPC Chair Joe Lang, with Omaha Public Power District, told the Strategic Planning Committee on April 16.

SPP says the tariff change is necessary because large loads have increased load forecasts significantly. However, load-responsible entities could fall short by 17 GW by 2030, according to their submissions, and "large uncertainties" still exist with the backlogged generator interconnection queue.

The Resource and Energy Adequacy Leadership (REAL) Team worked with staff to develop the ERAS. It added modifications to attestation and LRE-ceiling capacity suggested by Evergy and Xcel/Southwestern Public Service (SPS) and Empire District Electric, respectively, before endorsing it April 2.

### Why This Matters

The expedited process is designed to help load-responsible entities meet their resource adequacy requirement, which is challenged by increasing large loads that have increased demand and SPP's backlogged generator interconnection queue.

MOPC approved the provisional process policy in October 2024, and the RSC subsequently endorsed its cost-allocation concept. The current process is base-plan funded; under the new methodology, upgrade costs will be assigned directly to the customer, with base-plan funding covering the remaining cost.

During MOPC's hourslong discussion, staff accepted Oklahoma Gas & Electric's suggestion to extend the deadline for ERAS projects' commercial operations date from five to seven years, allowing for supply chain issues.

"Let's allow for some of [the] things that an LRE can control to happen and still get resources on to meet the [planning reserve margin] as quick as possible," OG&E's Brad Cochran said.

Evergy also modified its own comments to add a second LRE ceiling provision: the projected deficiency multiplied by the ceiling multiplier or the projected deficiency plus the less of either 419 MW or 50% of the LRE's highest summer season or winter season net peak demand.

The final measure passed with 81.15% approval and five abstentions. All 18 transmission-owning members voted for RR668, but only 38 of 61 transmission-using members voted for the revision.

Not everyone was happy.

NextEra Energy's Jeff Wells said SPP's time, resources and efforts would be better supported clearing the existing GI queues.

"SPP has made substantial efforts … my estimates are rough, but there are approximately 180 GW currently in the queue," he said. "I would imagine that most of that could meet resource adequacy, so I think it would be important for SPP to focus on those current queues and unlocking those with [GI agreements] instead of creating a new queue exclusive to LREs. It's unduly discriminatory."

Christy Walsh, with Natural Resources Defense Council-Sustainable FERC, suggested waiting until the commission responds to MISO's ERAS filing, which is opposed by independent power producers, environmental organizations and several state regulatory bodies. MISO's proposal also drew pushbacks from eight former FERC commissioners, who said it threatens the open-access principle. (See *MISO Fast Lane Proposal Disadvantages IPPs, Retail Choice States, Critics Tell FERC*.)

"I think that should be concerning to all of us, and I, at the very least, think we need to wait," Walsh said, noting MISO asked for action by May 17. "At least wait to see what FERC does there, to see if this proposal even has legs. I think SPP hasn't really adequately justified the need and we haven't done enough to ensure that the resources that are going to be in ERAS will actually come online in time. We're doing a lot here that violates fundamental tenets for FERC rules and isn't actually going to fix any problem that's been identified."

"The biggest problem that exists with this proposal … is the challenge, the danger it poses to open access. The idea that one set of entities [has] the ability to unilaterally make a decision about who gets access to the grid runs directly contrary … to what has been established by FERC over the last two-and-a-half decades in multiple orders," echoed Steve Gaw, with the Advanced Power Alliance.

SPP's Steve Purdy, technical director of engineering policy, responded to concerns that the proposal helps some entities by allowing them to jump ahead of projects stalled in SPP's queue.

"I don't know that a restudy constitutes queue-jumping, but all along, we've said that the ERAS requests are going to get higher priority than anything that's already been [studied] and that hasn't had a GIA," he said. "If you want to characterize that as queue-jumping, you can."

Jeff Wells, NextEra Energy | © *RTO Insider*

Purdy agreed with stakeholders that the ERAS process could lead to costs being shifted to SPP's transmission planning process, but said he didn't think it would be "dramatic."

"That's been a recognition all along, with the understanding that the purpose of ERAS is resource adequacy to benefit the entire footprint," he said. "The rationale, if you will, is for those costs to be borne by the larger footprint in order to reinforce our resource adequacy."

LREs will be able to determine which projects go to ERAS, Purdy added, but said they will be limited by the planning reserve margin (PRM). Perhaps worn down by the ERAS discussion, committee members quickly approved without further feedback an increase to the 2029 PRM (*RR664*). The summer PRM will go from 16 to 17% and the 2029/30 winter PRM will go from 36 to 38%.

The tariff change passed with 82.54 approval. Four of 18 TOs voted against the measure and eight of 63 transmission users.

## 'Chicken & Egg' Issue

MOPC unanimously approved a provisional load process (*RR672*) that allows transmission customers to add load to the system when they don't have enough designated resources to cover their 10-year load forecast (including losses). The measure is subject to secondary stakeholder groups' approval.

"If ERAS is the chicken, this is the egg," said Evergy's Derek Brown, chair of the Transmission Working Group. "So, resources versus load. We need a way to bring loads online faster that don't have resources procured for them yet."

The new planning process replaces a tariff attachment that required costly studies when customers didn't have enough firm resources.

MOPC approved the provisional process policy in October 2024, and the RSC subsequently endorsed its cost-allocation concept. The current process is base-plan funded; under the new methodology, upgrade costs will be assigned directly to the customer, with base-plan funding covering the remaining cost.

SPP plans to file the tariff revision with FERC in June, assuming it secures board and RSC approval.

"We have loads that are waiting to connect that would rely on this process," Brown said. ■

# FERC OKs Final SPP Markets+ Compliance Filing

FERC said in a letter order April 17 that it has accepted SPP's proposed compliance revisions to its Markets+ tariff that clarify five issues (*ER24-1658*).

The commission accepted SPP's tariff in January 2025 but asked the grid operator for further clarification in five areas: transmission availability, transmission opt-outs, Markets+ transmission contributor responsibilities, resource-aggregation mitigation and the seasonal hydroelectric offer curve's mitigation methodology.

FERC said the proposed revisions comply with its directives in the January order and accepted the modifications.

SPP's legal counsel told *RTO Insider* the compliance filing amounted to clarifying six sentences in its application. One of those was the same sentence written twice.

SPP first filed its Markets+ tariff in March 2024. FERC responded in July with a deficiency letter outlining 16 issues to be addressed. The RTO's response in January resulted in the commission's approval. (See *SPP Markets+ Tariff Wins FERC Approval*.)

## Operations Review

FERC on March 31 granted in part and denied in part Basin Electric Power Cooperative's request for transmission rate incentives for three 345-kV projects in North Dakota's portion of the Bakken Formation (*EL24-140*).

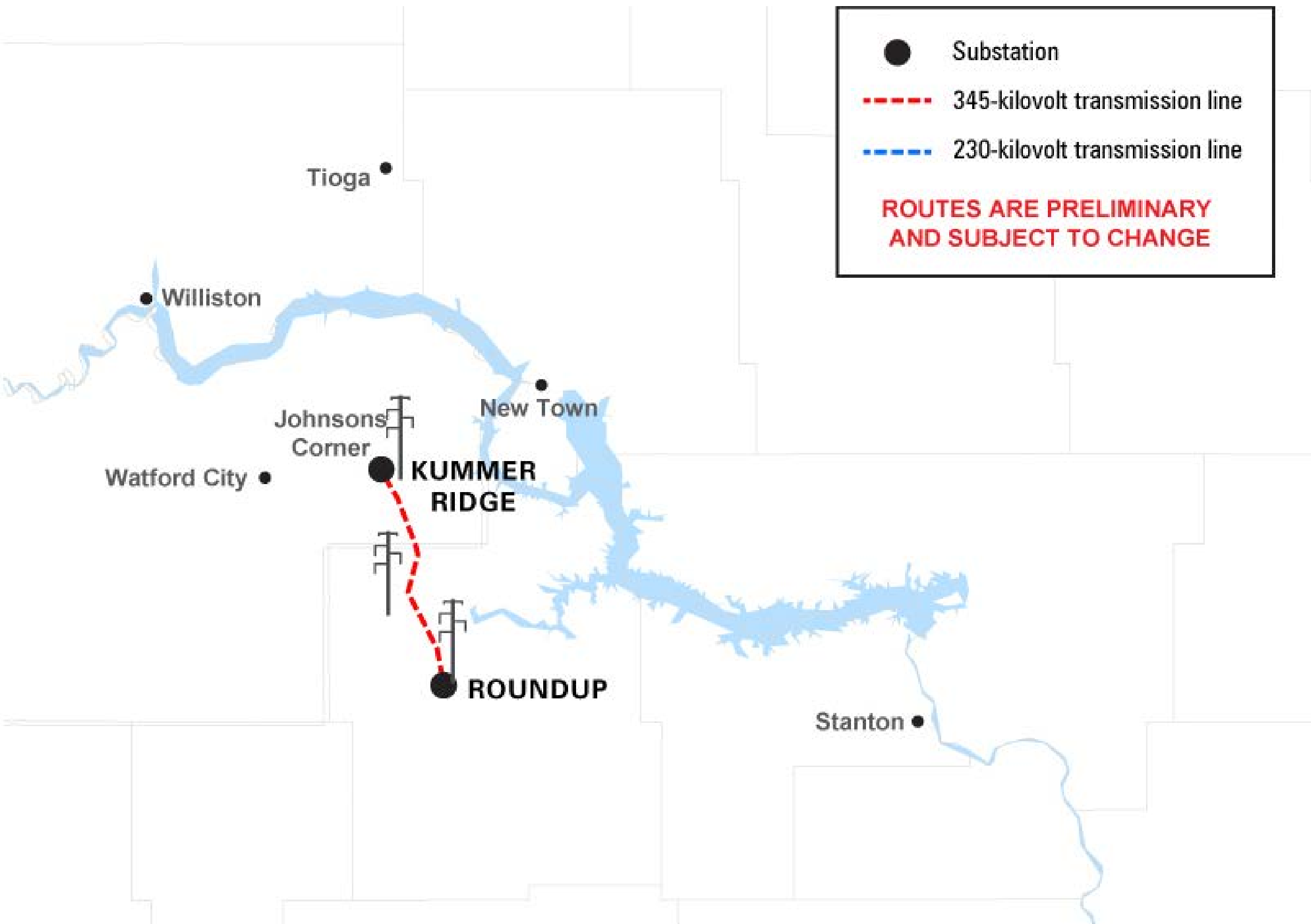
The commission granted Basin's request for abandoned-plant and hypothetical capital structure incentive for two of the projects but denied the latter incentive for the third, the 33-mile *Roundup-Kummer Ridge project*.

FERC found Basin's request for a 50-50 debt-to-equity hypothetical capital structure incentive for the Roundup-Kummer Ridge project had not demonstrated the project had any remaining risks or challenges given that the in-service date was in the past. The line was energized in December 2024.

All three projects were identified as part of the SPP 2021 Integrated Transmission Planning's 10-year assessment.

Commission Chair Mark Christie both concurred and dissented in part with a separate statement. He agreed with the capital structure incentive's denial for the Roundup-Kummer Ridge project and dissented with the approval of the other two incentives. Christie said he dissented on the same reasoning as his prior dissents on the topic, where he has argued FERC should revisit granting such transmission incentives because they unfairly transfer wealth and risk. ■

*— Tom Kleckner*




Basin Electric's Roundup-Kummer Ridge project. | *Basin Electric Power Cooperative*

# SPP Appoints New Senior Director of Seams and Western Services

## RTO Veteran Will Tackle Key Challenge for Operators of the Region's Day-ahead Markets

*By Robert Mullin*

SPP has appointed Jim Gonzalez as its new senior director of seams and Western services, in what will be a highly visible position in the RTO as it continues to develop Markets+ ahead of its expected launch in 2027.

Gonzalez will take over a role held by Carrie Simpson since 2022, who in March was *promoted* to SPP's vice president of markets. (See *SPP Brings Back Ex-staffer to Develop Western Services*.)

"Jim has played a key role in the development and administration of SPP's market services for over a decade," Simpson said in an April 21 release announcing the appointment. "His extensive knowledge and leadership will be invaluable to SPP's work in the West."

According to the release, Gonzalez "will direct the ongoing development and implementation of Markets+ … and other electricity services in partnership with SPP's stakeholders," as well as serve as the staff secretary for the Markets+ Participant Executive Committee (MPEC), the policymaking group representing the market's participants.

"I'm thrilled to be part of such a great team," Gonzalez said. "SPP and its stakeholders have done a tremendous job developing affordable, reliable energy services, and I'm ready to build on that success to bring a market that delivers substantial value to the Western Interconnection."

According to his LinkedIn profile, Gonzalez joined SPP in 2008 as an engineer, worked his way through the ranks into management positions in real-time operations and currently is the RTO's technical director of market policy and operations. He holds a bachelor's degree in electrical engineering from the University of Arkansas.

"Gonzalez is an expert in market and system operations and has held various positions at SPP contributing to market development and the reliability of the electric grid," SPP said in the release.

Gonzalez likely will lead the effort to tackle what industry participants expect to be a key challenge for the West as Markets+ is rolled out in parallel to CAISO's Extended Day-Ahead Market (EDAM): how to deal with the politically complicated and physically non contiguous seams running between the two markets.


Jim Gonzalez, SPP | © *RTO Insider*

### Why This Matters

The issues stemming from the seams between SPP's Markets+ and CAISO's EDAM promise to be extremely complicated, according to many Western industry participants and neutral market experts.

EDAM supporters have raised strong concerns about market seams. Markets+ backers — including the Bonneville Power Administration and Powerex — have played down the significance of the issue, calling it "manageable" while acknowledging the two market operators will have to address challenges. (See *Seams Concerns Won't Drive Day-ahead Market Decision, BPA Says*.)

SPP has pointed to its own experience in managing the seams between its market and those of its neighbors. (See *SPP's Experience with Seams Could Help Markets+*.)

But others have taken a more cautionary view.

"This is a special situation that you're going to have in the in the West," Richard Doying, vice president at Grid Strategies, said during the April 9 meeting of the Regional Issues Forum, a stakeholder body for CAISO's Western Energy Markets. "It will be difficult to deal with, just because we don't have any good historical precedents for how we would deal with this — and that is, we have currently a non contiguous market footprint."

"We don't have any existing markets where the markets are disconnected and they're in their own isolated zones without physical transmission connected," Doying said of Markets+. ■

# SPP MOPC Briefs

## Members Pass Last of HITT's 2019 Recommendations

HOUSTON — The SPP Markets and Operations Policy Committee has endorsed the last of 21 recommendations made by a task force that reviewed the RTO's transmission and market operations in the last decade.

The proposed tariff change (*RR665*) would establish "subregions" for the cost allocation of future byway (between 100 and 300 kV) upgrades.

"It's been a long time coming," Evergy's Derek Brown, a supporter of the revision request, said during MOPC's April meeting. "We just need to know the size of the subregions, which we now have."

SPP said the tariff change could be implemented next year, once it receives approval from the Board of Directors, state regulators and FERC.

"I'll just share Evergy's opinion that we should try and move faster than that, if possible," Brown said. "The policy has been approved for a long time now. We have some of the largest portfolios we've ever seen that we just went through the last few years, and we have another large one, potentially, in the 2025 [Integrated Transmission Planning assessment]. Cost allocation has a big impact on those discussions."

The change, as developed by the Cost Allocation Working Group's state regulatory staff, would decouple SPP's Schedule 9 (zonal rates) and Schedule 11 (highway/byway) transmission pricing zones and create larger Schedule 11 subregions of existing zones. Two-thirds of the cost of byway upgrades would be allocated to the subregion where they are connected, with the remaining 33% allocated to the SPP footprint.

Similar to 300-kV and above highway projects, new base plan upgrades larger than 300 kV would be allocated RTO-wide.

The change must be approved by the board and Regional State Committee when they meet May 5.

MOPC approved the proposed tariff change with 75.99% approval. Six of 17 transmission owners and seven of 55

OPPD's Joe Lang (right) chairs the MOPC meeting with Vice Chair Olivia Hough, of City Utilities of Springfield. | © *RTO Insider*

transmission users voted against it.

SPP's board created the *Holistic Integrated Tariff Team* (HITT) in March 2018 to conduct a comprehensive review of the grid operator's cost-allocation model, transmission planning processes, Integrated Marketplace and real-time operations. After a year of discussion, the 15-person HITT published a *report with 21 recommendations*. (See *HITT Shares Draft Report with SPP Stakeholders*.)

The tariff change was hung up for several years by work on another HITT recommendation to adopt a policy creating an appropriate balance between cost assessed and value attained from energy and network resource interconnection service products and generating resources with long-term firm transmission service.

"Not everybody got what they wanted on this, but this really is bringing about what was intended; what HITT wanted to do," said Golden Spread Electric Cooperative's Mike Wise, who was a HITT member. "I remember how long it took to get through [the other recommendations], and finally when we did, we breathed a sigh of relief. And then we started working immediately on [RR665]."

## 2025 ITP: Waiting on Study Request

SPP's manager of transmission planning, Kirk Hall, told MOPC that the 2025 Integrated Transmission Planning assessment will be the most complex study to date.

He based his comments on a potential 9-GW generation shortfall; exponential load growth that has resulted in 57,000 non-converged contingencies (too many needs for one Microsoft Excel workbook); large loads interconnected with substations that have substandard transmission; and other factors.

"People have asked me, 'What do you think the portfolio is going to look like this year?' And I don't really know, but I think it's going to be somewhere between diddly-squat and a gazillion," he said to laughter. "Somewhere in the middle. We're just not quite there yet."

Hall said staff were "smack dab" into the 2025 window for detailed project proposals (DPPs), which closed April 20.

"The transmission planning team is going to come in Monday morning, bright-eyed and bushy-tailed, and ready to start validating," he said. "We're anxiously awaiting those DPPs coming in."

The 2025 study has completed its needs assessment but is in yellow status because the DPP submission window was extended. Hall said mitigation steps are being taken and staff are planning on-time approvals in the October MOPC cycle.

The 2026 ITP, which begins the transition into SPP's Consolidated Planning Process (CPP) assessments, is also underway and developing its models. The 2027 ITP's scope efforts should begin by late summer, Hall said.

Following the quarterly ITP update, MOPC endorsed a pair of motions recommended by the Transmission and Economic Studies working groups: *scope changes* that update the resilience language, and staging resilience projects. Those projects that also have economic, reliability, policy or operational needs will be staged based on the earliest need date identified; resilience-only projects will be staged as determined by model extrapolation and interpolation methodologies.

In other transmission-related issues, MOPC also:

- endorsed a tariff change (*RR673*) that would eliminate a requirement to have met definitive interconnection system impact study (DISIS) requirements before submitting an interim service request. Instead, transmission customers can make that request when a DISIS open season is delayed.
- accepted the Project Cost Working Group's recommendation that 12 upgrade projects exceeding their *estimated in-service date thresholds* by more than 90 days be deemed reasonable and acceptable. Members also endorsed the baseline used to evaluate future in-service delays.

## GI Queue Backlog on Track

SPP's effort to relieve the generator interconnection queue backlog is on track, with four study clusters expected to reach the GI agreement stage in 2025, Natasha Henderson, senior director of grid asset utilization, told the committee.


Natasha Henderson, SPP | © *RTO Insider*

Henderson said that while the 2017 and 2018 clusters are in the GIA stage, transmission customers in the 2022 cluster will receive their GIAs within three years of submission.

The key cluster is the 2026 DISIS, which SPP hopes will be the first of its CPP. The new study process is expected to be brought before MOPC in July and the board in August. Assuming timely FERC approval, it could be active in 2026.

"The timing actually aligns so that we can either open the 2026 DISIS, or those same generators could go into the CPP," Henderson said. "Either way, this is the time frame in which we would anticipate opening the 2026 DISIS window [for study requests]."

She said the timing could also benefit members of *SPP's RTO expansion* into the Western Interconnection, set to go live in April 2026.

Excluding the record 2024 DISIS (102 GW), SPP staff are currently studying 325 projects representing 65.8 GW. Solar, wind and batteries account for all but 10% of the queue. Henderson said 24 GW have GIAs but have not reached their commercial operations date; an additional 5 GW have CODs in 2025, she said.

More than 150 projects have already withdrawn from the 2021, 2022 and 2023 clusters, taking with them 33 GW of capacity. Those withdrawals can shift upgrades and associated costs. They will be reassessed in the next planned study.


SPP's Paul Suskie updates MOPC on the Z2 resettlement status. | © *RTO Insider*

## SPP Waiting for FERC's Response on Z2

SPP says a FERC response is imminent for its plans to resettle invoices for transmission upgrades under tariff Attachment Z2, a process that has bedeviled the RTO since 2016. (See "Grid Operator Waiting for FERC Order to Resettle Z2 Funds," *SPP Markets & Operations Policy Committee Briefs: Oct. 15-16, 2024*.)

"We, as well as many parties, have asked for an order soon, sooner rather than later, because of the significant interest that is accruing on those Z2 refunds," General Counsel Paul Suskie told MOPC. "We continue to work hard to be proactive and addressing issues, answering questions and providing information in a transparent way."

Under Z2, transmission upgrade sponsors receive credits from any upgrade users whose service could not be provided "but for" the upgrade. The attachment also requires the RTO to invoice the charges monthly and to make any adjustments within one year.

However, software problems delayed the attachment's final implementation for eight years before 2016, during which the RTO did not invoice for the upgrade charges. FERC approved a waiver request to settle more than 365 days in arrears, but in 2019, the commission reversed course and said SPP should have settled Z2 from only September 2015 forward. (See *FERC Reverses Waiver on SPP's Z2 Obligations*.)

In January 2022, the grid operator filed with FERC an update to its proposed refund plan, submitted in 2019. SPP made an informational update to the commission in September 2024. FERC has made it clear SPP can't process refunds without an order, Suskie said.

When the order comes, SPP plans to send out refund invoices with FERC interest for the March 2008-August 2015 operating days, accrued to the current invoice date. Once the resettlement system is deployed in about a year, invoices would be issued for the September 2015-January 2020 operating days. Additional resettlements from February 2020 would be run monthly in the current settlement system, along with normal current day Z2 settlements, until they catch up to the operating month.

"At this point, we're waiting for a FERC order so that we can quickly issue the refunds and collect the money and issue the refunds, and then begin the process of building the models in the system so that we can start resettling 2015 to present," Suskie told *RTO Insider*. "Once FERC gives us an order, we're thinking it'll take us about four years to resettle it."


SPP's Casey Cathey explains revisions to the ITP assessments. | © *RTO Insider*

### 8 Tariff Changes

MOPC's consent agenda included eight NPRRs that would:

- *RR658*: prevent the uneconomic dispatch of demand response resources by creating an energy offer curve price floor equal to the net benefits threshold price for DR resources.
- *RR661*: introduce a new "TCR model" definition in the transmission congestion rights (TCR) tariff language by clarifying the congestion-hedging team's ability to adjust NERC-defined flowgates in the modeling process to match the day-ahead market topology and improve TCR funding.
- *RR662*: remove Form EIA-411 from the Integrated Marketplace protocols.
- *RR663*: develop inverter-based requirements based on reliability needs for SPP governing documents.
- *RR666*: clarify deadlines for market participants submitting project-related data for commercial model changes and provide a commercial changes submission due date column.
- *RR667*: add language clarifying that opportunity costs for hydro resources are excluded when obligations are imposed outside of the Integrated Marketplace. This does not include commitments ordered by a transmission provider or local transmission.
- *RR669*: update the ITP Manual with SPP's brand standards, correct small typographical errors and add consistent formatting throughout the document.
- *RR671*: remove the annual violation relaxation limits analysis' date requirement to create a more flexible timeline. ■

*— Tom Kleckner*

# EEI Names Drew Maloney as Next CEO

*By James Downing*

The Edison Electric Institute has selected Drew Maloney as its new CEO effective July 1, when he will succeed interim CEO Pat Vincent-Collawn.

Maloney will be the permanent replacement for Dan Brouillette, a former Secretary of Energy who stepped down last fall after less than a year at the helm of the investor-owned utility trade group. He had a brief tenure compared to former CEO Tom Kuhn, who ran EEI from 1990 through 2023.

"Drew Maloney's extensive public policy expertise, financial and energy sector work and trade association leadership will be a tremendous asset to EEI member companies and the millions of customers we serve," said EEI Board Chair Maria Pope. "His proven record in Washington, D.C., navigating some of the most complex policy landscapes by building effective coalitions, will be invaluable as our industry works to meet increasing electricity demand with a focus on keeping customer bills as low as possible."

Maloney has been CEO of the American Investment Council since 2018. The AIC represents "the private investment industry" that includes private equity and major investors in the power sector. His

Drew Maloney | *EEI*

work there included efforts to promote investment in energy production and critical infrastructure, EEI said.

Before working at the AIC, Malone was Assistant Secretary of the Treasury for Legislative Affairs during President Donald Trump's first term. From 2012 to 2017 he was a vice president at Hess Corp., which was involved in the power industry early in his tenure before it sold that part of its business to focus on oil. Before working at Hess, Maloney was CEO of Ogilvy Government Relations, where part of his job was to promote investment in energy production and, according to lobbying disclosures, PJM was one of his clients.

"As AI transforms our industries, manufacturers return to our shores and daily life becomes more electrified, the strength and resilience of America's energy grid is more critical than ever," Maloney said in a statement. "EEI's member companies make up an innovative and dynamic industry, and I am excited to work with them to lay out and execute policies to support critical infrastructure investment, accelerate the deployment of domestic energy sources and keep energy affordable and reliable for customers."

Working with the Trump administration and Congress, Maloney said EEI can advance and strengthen energy independence and economic prosperity. Maloney holds a law degree from the Catholic University of America and earned a bachelor's degree at Randolph-Macon College.

TXNM Energy CEO Vincent-Collawn has pulled double duty, serving as interim CEO of EEI since November while also continuing to run the utility holding company with operations in Texas and New Mexico. She has a long involvement with EEI's board, becoming the first woman to chair the board of the trade group for a one-year term from 2017 to 2018.

"On behalf of the EEI board, I also want to thank interim President and CEO Pat Vincent-Collawn for her successful stewardship of the organization," EEI Chair Pope said. ■

# Company Briefs

## BGE Names Olivier New CEO

Baltimore Gas & Electric last week named Tamla Olivier as its new CEO, effective May 1.

Olivier joined Exelon about 15 years ago and has been the senior vice president and chief operating officer of Pepco Holdings — another subsidiary of Exelon — since 2021.

Current CEO Carim Khouzami will move to a position at parent company Exelon.

More: *The Baltimore Banner*

## Microsoft, Fidelis Partner on Carbon Capture Project

Fidelis last week announced it is partnering with Microsoft on a proposed $800 million facility at the Port of Greater Baton Rouge.

Microsoft signed a contract with Fidelis' portfolio company AtmosClear to remove 6.75 million metric tons of $CO_2$ over a 15-year period as part of a larger effort by the tech giant to offset its greenhouse gas emissions, Fidelis said. It's unclear where the CO2 will be sequestered, though several companies in the region are seeking permits for wells to inject and store it in rock formations deep underground.

Fidelis said a final investment decision on the project is expected this year. Construction would begin in 2026, and commercial operations would start in 2029.

More: *The Advocate*

## Schneider Electric Unveils Data Center Consulting Service

Schneider Electric last week announced the launch of EcoConsult for Data Centers, a consulting service designed to help data center and IT managers achieve operational efficiency and maximum uptime.

Schneider Electric said its EcoConsult service is a global network of more than 250 consultants, 430 service centers and 6,500 service representatives that helps ensure consistent, reliable and high-quality service worldwide.

About 36% of U.S. data centers are more than 10 years old and lack a facility-wide proactive asset management strategy, according to Schneider. Their service aims to provide a roadmap toward ensuring maximum uptime, reduction in total cost of ownership and life extension of the infrastructure.

More: *Schneider Electric*

# Federal Briefs

## EPA Exempts Coal Plants from Biden-era Toxic Chemicals Rule

The EPA last week granted 66 coal-fired power plants a two-year exemption from federal requirements to reduce emissions of toxic chemicals such as mercury, arsenic and benzene.

A list posted on the EPA's website lists 47 power providers that are receiving exemptions from the Biden-era rules under the Clean Air Act, including a regulation limiting air pollution from mercury and other toxins. The exemptions also apply to four plants operated by the Tennessee Valley Authority.

More: *The Associated Press*

## USDA Cancels $3B Climate-friendly Farming Program

The U.S. Department of Agriculture last week said it canceled a $3 billion program for climate-smart farming projects after a review found it did not align with the priorities of the Trump administration.

The Partnership for Climate-Smart Commodities allocated $3 billion to 135 projects in every state that encouraged soil health, carbon sequestration, reduced methane emissions and other climate-friendly practices, according to the USDA website.

The USDA determined that most of the projects provided too little money to farmers and too much to administrative costs.

More: *Reuters*

## Report: $8B in Renewable Energy Investments Canceled in Q1

The first three months of 2025 saw nearly $8 billion in investments canceled and 16 new large-scale factories and other projects abandoned or downsized in the renewable energy industry, according to E2's latest Clean Economy Works monthly update.

The $7.9 billion in investments withdrawn since January are more than three times the total investments canceled over the previous 30 months combined, the report said.

Still, companies continue to invest, as businesses in March announced more than $1.6 billion in investments for new solar, EV and grid and transmission equipment factories.

More: *Solar Builder Magazine*

# State Briefs

## CONNECTICUT

### Gillett Confirmed for 2nd PURA Term

Marissa Gillett last week was confirmed by a 21-0 Senate vote for a second four-year term as the Public Utilities Regulatory Authority's chair.

Gillett, who has led the authority since 2019, was confirmed with none of the chamber's 11 Republicans participating due to a planned walkout.

The Senate also voted to confirm nominee David Arconti.

More: *CT Mirror*

## ILLINOIS

### Byron Nuclear Center to Receive $355M Upgrade

Constellation Energy last week announced it plans to invest $355 million in the Byron Nuclear Power Station to increase the site's output and extend its life of operation.

The upgrade, set to begin in 2026 and finish in 2029, will replace six low-pressure turbines and two high-pressure turbines. The new turbines will generate an additional 80 MW and raise the facility's output to 2,427 MW.

More: *Shaw Local News Network*

## INDIANA

### Gov. Braun Signs 'Construction-in-progress' SMR Bill

Gov. Mike Braun last week signed a bill into law that enables public utilities to petition state regulators to recover costs for developing small module nuclear reactors.

The law allows the state's investor-owned utilities to recover the costs of developing SMRs from ratepayers before receiving a certificate of public convenience and necessity.

More: *Indianapolis Star*

### Indiana Michigan Power Eyes Purchase of 870-MW Gas Plant

Indiana Michigan Power (I&M) has asked the Utility Regulatory Commission for permission to buy the Oregon Clean Energy Center.

The existing 870-MW natural gas plant is one component of the utility's Future Ready plan as it tries to meet power demand through 2044. Power demand is expected to more than double from approximately 2,800 MW in 2024 to more than 7,000 MW in 2030.

I&M said it anticipates a decision from the URC on the filing in early 2026.

More: *Power Engineering*

## MASSACHUSETTS

### DEP Delays Enforcement of Clean Truck Requirements

The Department of Environmental Protection last week announced a delay in its enforcement of minimum electric truck sales requirements.

Under the Advanced Clean Trucks regulation the state adopted following California's lead in 2021, medium- and heavy-duty vehicle manufacturers are required to produce and sell a gradually increasing percentage of zero-emission vehicles starting in model year 2025.

The DEP said some manufacturers said the sales requirements "are too difficult to meet" and municipalities have said only a limited supply of clean trucks are available to comply with the standards. The department, which had previously indicated it would be flexible about enforcement of some provisions, said it "will exercise enforcement discretion by not taking enforcement action against manufacturers that do not meet their Model Year 2025 or Model Year 2026" sales requirements as long as those manufacturers continue to provide internal combustion vehicles to distributors.

More: *State House News Service*

### Massport Hires Climate Chief

The Massachusetts Port Authority last week announced it has hired Jill Valdes Horwood as its first chief climate and resilience officer.

The job includes helping the agency, which owns and operates Logan International Airport, get to its goal of net-zero greenhouse gas emissions by 2031.

More: *CommonWealth Beacon*

## OHIO

### Power Siting Board Denies Solar Application

The Power Siting Board last week unanimously denied Stark Solar a certificate to construct, operate and maintain a 150-MW solar farm in Stark County.

The board said there were many benefits to the project, but the benefits do not outweigh negative impacts to residents near the project. It cited opposition from local governments and residents as reasons for its denial.

The company, or other intervenors in the case, could still appeal the decision.

More: *Canton Repository*

## PENNSYLVANIA

### EV, Hybrid Owners to Pay 'Road-user' Charge


Electric and plug-in hybrid vehicle owners will have to pay a fee each year to help with road maintenance beginning May 1.

The annual fee is $200 for 2025 for full electric vehicles and $50 for plug-in hybrids. In 2026, that amount jumps to $250 for EVs and $63 for hybrids. After that, the fee would be reset based on the prior year's consumer price index.

The fee is expected to generate $16 million in 2025, which would be deposited in the state's Motor License Fund that helps pay for construction, maintenance, repair and safety improvements on highways and bridges.

More: *Penn Live*

## TEXAS

### Senate Approves Fines for Deceiving Solar Customers

The state Senate voted 22-8 to approve

a measure that would give a state board the authority to fine residential solar companies as much as $100,000 for deceiving customers.

A *San Antonio Express*-News analysis of consumer complaints filed with the Office of the Attorney General found that more than 50% said they were making payments on systems that were unfinished or faulty or that never worked. Another 28% said their systems were generating much less power than promised and usually not enough to offset the cost.

The bill now heads to the House.

More: *Houston Chronicle*

# VIRGINIA

## Balico Application for Pittsylvania Data Center Denied

The Pittsylvania County Board of Supervisors last week denied Balico's application to rezone 750 acres for a data center and power generation project.

Balico tried to withdraw its application last week; however, that move was also denied by the board. Balico will now need to wait a full year before it can submit another proposal.

More: *Danville Register & Bee*; *Cardinal News*

## Mecklenburg County Blocks Future Large-scale Solar Development

The Mecklenburg County Board of Supervisors last week voted unanimously to remove utility-scale solar as a future allowed land use.

County Administrator Alex Gottschalk said the county was an early adopter of utility-scale solar but "the cons have, to date, far outweighed the pros in most people's minds."

The supervisors will allow three pending projects to continue their permitting process, although they can approve or deny the projects as they see fit.

More: *Cardinal News*

# WASHINGTON

## NextEra Energy Plans Grant County Solar Project

NextEra Energy Resources last week announced plans for the Dry Falls Solar project in Grant County.

The facility would generate up to 400 MW while being complemented by 1,600 MW of battery storage.

The proposal has been submitted to county commissioners, while the company hopes to begin construction this summer.

More: *Columbia Basin Herald*

# WYOMING

## PSC OKs Rocky Mountain Power Rate Hike

The Public Service Commission last week approved a rate hike for Rocky Mountain Power.

The PSC unanimously accepted a settlement between Rocky Mountain Power, the Wyoming Industrial Energy Consumers group and the Office of Consumer Advocate. The deal reduced the utility's original request for a $123.5 million (14.7%) increase to a $85.5 million (10.2%) increase.

The average residential bill will climb by about $14/month.

More: *WyoFile*