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YES ENERGY

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YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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

MISO

MISO Requires Load Shed in New Orleans to Avoid Grid Instability

Entergy

Diagnosing exactly what happened in Louisiana, and why, surely will be debated in MISO in the coming weeks and months, along with how to prevent it from happening again.

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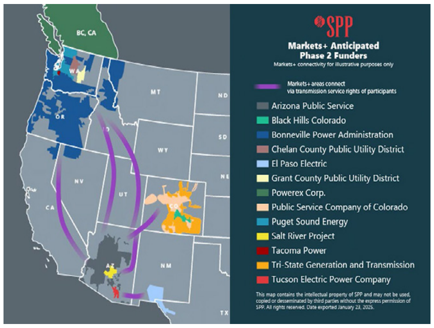
FPA Section 202(c) effectively is a federal backstop for reliability-must-run deals to keep power plants needed for reliability open, overruling environmental laws in the process. The Trump administration's order signals a more aggressive use of the authority.

SPP CAISO/WEST



SPP

SPP Readies Participants for Next Phase of Markets+ (p.40)

SPP has set a soft deadline of July 23 for submitting agreements and retaining seats on stakeholder groups. The rosters will be posted for the stakeholder-led Markets+ Participant Executive Committee's approval and then confirmed by the MPEC during its Aug. 12-13 meeting.

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In this week's issue

The Facts About FERC Order 1920 and Why It's Essential

By Gretchen Kershaw

Why This Matters

Gretchen Kershaw says utilities are investing more than ever in upgrading a rapidly aging grid, and Order 1920 provides a collaborative road map for more efficient and cost-effective grid upgrades.

Gretchen Kershaw

As the tides of "deregulation" swell, I write to set the record straight on FERC Order 1920. As Mark Twain said, "Get your facts first, then you can distort them as you please." Here are the facts.

We need a significant amount of transmission in this country. Study after study shows a pressing need today as well as in the future, and that need is driven by threats to the reliability and resilience of the grid, high energy costs, and congestion and constraints on the existing system.

At the same time, demand is *surging*, driven by electrification, increases in domestic manufacturing, and, of course, new load from artificial intelligence (AI) data centers and other large customers.

So, everyone is asking: How do we meet potentially exponential demand growth reliably and affordably? Generation will be needed, but it cannot meet this demand alone; transmission is essential. So is FERC's Order No. 1920. Here are a few key facts.

Fact 1: The status quo incremental and reactive approach to building the grid we need is the most expensive option and will contribute to rising electricity bills. FERC aimed to fix the broken paradigm with Order 1920, establishing a baseline across the country that reflects best practices, such as planning on a 20-year forward-looking basis. Well-planned transmission, as envisioned by Order 1920, benefits all users of our electric system.

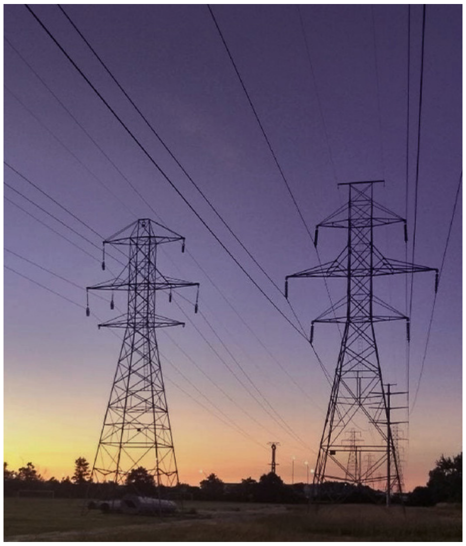
Fact 2: Well-planned transmission improves reliability and resilience. The reality is that *all generators* have outages, whether "behind the meter" or grid-connected. A more networked system, connecting areas that have peak loads and generation outages at different times, always has been the way to ensure steady power supply.

Looking at extreme weather events, transmission consistently allows more resources to be shared across regions and move energy from where it is available to where it is needed. Witness Winter Storms *Uri* and *Elliott*, where regions that could import power avoided prolonged outages that plagued regions that were more islanded.

As my colleague Michael Goggin says: We need a grid bigger than the weather. Building this insurance policy against future extreme events requires planning that is proactive and that accounts for a wide range of drivers and addresses uncertainty by identifying projects that are beneficial under multiple scenarios.

Fact 3: Well-planned transmission saves consumers money. Electricity rates are increasing for several reasons, one of which is transmission. But despite transmission spending hitting an all-time high in recent years, the *miles* of new high-voltage transmission that is being built has dropped year-over-year.

So, transmission owners are investing — not surprising, given our aging electric grid — but not adding new large-scale transmission capacity nearly fast enough. The *National Transmission Planning Study*, released by DOE last year, found the lowest-cost electricity system to meet future demand and reliability needs includes substantial transmission expansion — and that accelerated and coordinated expansion could save upward of $490 billion through 2050. We cannot afford to abandon Order No. 1920; instead, we should implement it faster to significantly benefit sooner.



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Fact 4: Order 1920 benefits all kinds of generation, and our country needs more transmission *no matter the generation type*. Abundant American energy supply is within reach. But we cannot access it reliably and affordably without transmission.

Let's be clear: Utilities are investing more than ever in upgrading a rapidly aging grid. Order 1920 provides a collaborative road map for more efficient and cost-effective grid upgrades. Grid hardening is critical, as is squeezing more from our existing system by deploying *grid enhancing technologies and high performance conductors*.

Congress knew this when it acted, on a bipartisan basis, to establish federal funding programs in the Infrastructure Investment and Jobs Act in 2021 for *just this type of investment*. Regrettably, delays in these critical enhancements may indeed happen, but not from Order 1920; instead, delays may happen from blocking use of federal funds specifically for these needs.

Those are the facts. How impactful Order 1920 will be is yet to be seen, but to cut it off at the pass is to threaten grid reliability and resilience, impose higher costs on consumers, and threaten America's ability to compete in the global AI race. ■

Gretchen Kershaw is chief operating officer and vice president of strategy at Grid Strategies LLC.

Trump Orders Nuclear Regulatory Acceleration, Streamlining

Wholesale Change in Approach and Staff Reductions Directed for NRC

By John Cropley

Plant Vogtle Units 3 and 4, the first U.S. commercial reactors to come online in more than 30 years. The reactors were completed seven years behind schedule at a cost of more than $30 billion. | *Georgia Power*

President Donald Trump *moved to speed up nuclear power development* May 23 with a series of executive orders designed to ease federal regulations on the sector.

The measures require the Nuclear Regulatory Commission to *issue timely licensing decisions*, allow *construction on federal lands* to serve national and economic security, *attempt to re-invigorate* the nuclear energy industrial sector and allow for reactor design *testing at nuclear laboratories*.

The end goal is to quadruple U.S. nuclear power production by 2050. A shorter-term goal is to have three new experimental reactors online by July 4, 2026.

Nuclear industry executives spoke appreciatively as they watched the president sign the orders, and advocacy groups not present at the ceremony issued a chorus of supportive comments.

But others raised concerns about the Trump administration speeding up review of nuclear development and construction, particularly as the industry attempts to pivot from time-tested designs to new and unproven technologies.

The narrative of commercial nuclear power in the United States is well-known: The nation pioneered the industry and built the largest reactor fleet in the world, then stepped back, completing zero commercial plants for 30 years. The nation's first new reactors in a generation were completed recently, far behind schedule and at stunningly high cost.

One after another, Trump and his invited speakers blamed this turn of events on federal over-regulation and said the executive orders would change that.

Why This Matters

The orders direct a radical revision of policy in an attempt to sharply increase U.S. nuclear power generation.

"We're not going to have cost overruns," Trump said.

"It's time for nuclear, and we're going to do it very big."

Reactions

The reporters gathered for the ceremony asked the president two almost cursory questions about the safety of nuclear energy, then quickly switched to tariffs and other topics.

Trump replied that nuclear generation has become very safe.

Neither he nor any of the speakers or questioners present drew any correlation between nuclear generation becoming safer at the same time as regulations on it were becoming more strict.

But others made that connection.

Edwin Lyman, director of nuclear power safety at the Union of Concerned Scientists, said in a news release: "By fatally compromising the independence and integrity of the NRC, and by encouraging pathways for nuclear deployment that bypass the regulator entirely, the Trump administration is virtually guaranteeing that this country will see a serious accident or other radiological release that will affect the health, safety and livelihoods of millions."

Shortly after Trump was inaugurated and began to assert power over independent federal regulators such as the NRC, Allison Macfarlane, the NRC chair from 2012 to 2014, warned in the *Bulletin of the Atomic Scientists* about the *dangers of faster, looser regulation* of the next generation of reactors now being designed: "These proponents — some with no experience in operating reactors — want the NRC to trust their simplistic computer models of reactor performance and essentially give them a free pass to deploy their untested technology across the country."

But others cheered Trump's moves.

Constitution CEO Joe Dominguez was present at the signing ceremony.

"The problem in the industry has historically been regulatory delay," he said. "Mr. President, you know this because you're the best at building big things. Delay in regulations and permitting will absolutely kill you."

He also noted "silly questions" by the NRC, such as the investigations into whether new reactors are suitable for a site adjacent to reactors that have been operating safely for decades. Addressing that one line of inquiry has cost Constellation $35 million each in three application processes, he added.

Jacob DeWitte, CEO of fast reactor developer Oklo, also was present for the signing and said, "Nuclear is a manifestation of energy dominance" and "changing the permitting dynamics is going to help things move faster."

ClearPath Action CEO Jeremy Harrell said in a news release: "These executive orders take a whole-of-government approach to move quickly in support of new deployments." Harrell also called for additional policy and financial support from Congress.

Nuclear Innovation Alliance CEO Judi Greenwald applauded the Trump administration's goals with the orders but raised concerns about some parallel actions: "Adequate staffing and funding are required for these goals to be met. Recent DOE staffing reductions and proposed budget cuts undermine the department's efforts and make it harder to implement these executive orders."

Greenwald added that the alliance has long thought the NRC needed to be more efficient, but sees it making significant progress and feels it important this not be undermined by staff cuts or conflicting directives: "NRC effectiveness, efficiency and independence are critical to the public, the industry and potential customers of U.S. nuclear technology both here and abroad."

The Orders

President Trump signed five executive orders May 23, four of them pertaining directly to nuclear energy and the fifth requiring federal research agencies to conform to *Gold Standard scientific practices*.

The nuclear executive orders are lengthy and detailed.

The NRC order, for example, specifies:

- reorganization and staff cuts, including a reduction in personnel and functions of the Advisory Committee on Reactor Safeguards;
- wholesale revision of NRC regulations and guidance;
- adoption of fixed deadlines;
- an expedited pathway for approval of reactors already tested by the departments of Defense or Energy; and
- consideration of nuclear energy's economic and national security benefits alongside the traditional safety, health and environmental considerations.

At times, the wording is blunt in its criticism of the NRC: "A myopic policy of minimizing even trivial risks ignores the reality that substitute forms of energy production also carry risk, such as pollution with potentially deleterious health effects."

Trump did not mention in his order that he also has moved to ramp up those other forms of energy production and remove safeguards against their deleterious effects.

Other actions ordered by Trump include:

- A nuclear reactor will be built and operational on a domestic military base within three years.
- The departments of Energy and Defense will explore categorical exclusions under the National Environmental Policy Act for the construction of advanced nuclear reactor technologies on federal sites.
- The State Department and other agencies will aggressively explore opportunities for export of U.S. nuclear technology to allies to bolster the U.S. nuclear industrial sector.
- DOE will release at least 20 metric tons of high-assay low-enriched uranium into a readily available fuel bank for private sector projects operating nuclear reactors to power AI infrastructure at DOE sites.
- The "severely atrophied" domestic nuclear fuel supply chain will be expanded.
- All relevant federal agencies will work together to develop solutions for the "difficult problem" of treatment of nuclear waste.
- Multiple efforts will be undertaken to build a workforce that can do all of these things. ■

TVA First U.S. Utility to Request SMR Construction Permit

Plan Presented as Means to Ease Deployment Nationwide

By John Cropley

The Tennessee Valley Authority crossed a milestone May 20, becoming the first U.S. utility to request a construction permit for a small modular nuclear reactor.

The facility would be built around a GE Hitachi BWRX-300 near Oak Ridge, Tenn., at TVA's Clinch River site, where plans to build a breeder reactor were pursued and then abandoned 40 years ago.

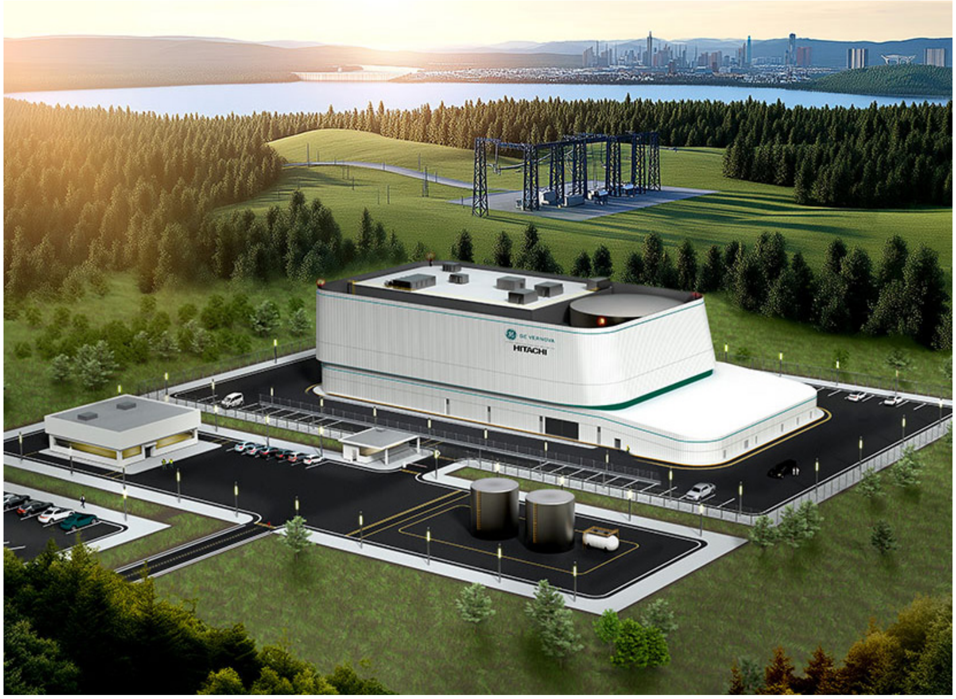
In its announcement, TVA said its plan has the best path to success because the site holds the first — and still only — early site permit issued by the Nuclear Regulatory Commission for an SMR.

But there are many competing plans. The SMR field is crowded with technology developers, site developers and would-be off-takers eager for the non-intermittent, emissions-free electricity this next class of nuclear reactors is expected to provide.

If the technology evolves as hoped, and if it is widely deployed, permitting and construction could be streamlined and standardized to the point that SMRs come online much more quickly and at markedly lower cost than their large-scale forebears.

TVA's milestone comes amid a series of firsts in the SMR sector:

- The NRC on May 13 accepted a construction permit application for *X-energy's first SMR*, which would power Dow Chemical's manufacturing facility in Seadrift, Texas, and be the first advanced nuclear reactor at an industrial site in the U.S.
- Ontario Power Generation on May 8 received provincial approval to build what is expected to be the first SMR to come online in North America, also a BWRX-300. (See *Ontario Greenlights OPG to Build Small Modular Reactor*.)
- In March 2024, TerraPower *submitted the first application* for permission to construct a commercial advanced reactor, its Natrium demonstration project in Wyoming. NRC's draft safety evaluation is underway.



A rendering shows the potential configuration of a GE Hitachi Nuclear Energy BWRX-300 small modular reactor facility. | *GE Vernova*

Why This Matters

The first-of-its-kind request could help advance the U.S. small modular reactor sector.

2024 and 2025 have seen many other SMR announcements. Most were not milestones, yet they carried a tone of confident certainty. But at least some amount of revision, delay or failure seems likely for these proposals, given all the financial, regulatory and technological hurdles standing between the announcements and start of commercial operation.

If nothing else, a key value prospect of SMRs — serial production of identical facilities — would be diluted if 10 technology developers all bring their assorted designs to market.

The Clinch River SMR project joins TVA — the country's largest public power supplier and a nuclear operator — with GE Hitachi Nuclear Energy, which has a decadeslong legacy of dozens of completed reactor projects worldwide.

TVA is leading an industry coalition in an application for up to $800 million in grant funding from the U.S. Department of Energy's Generation III+ Small Modular Reactor Program, designed to bridge the gap between the existing U.S. reactor fleet and more advanced designs.

TVA CEO Don Moul highlighted this in the official announcement. "This is a significant milestone for TVA, our region and our nation because we are accelerating the development of new nuclear technology, its supply chain and delivery model to unleash American energy," he said. "TVA has put in the work to advance the design and develop the first application for the BWRX-300 technology, creating a path for other utilities who choose to build the same technology."

TVA said preliminary site preparation for the SMR could begin as soon as 2026. ■

DOE Orders Michigan Coal Plant to Reverse Retirement

By James Downing

J.H. Campbell Power Plant in Michigan | *Consumers Energy*

Secretary of Energy Chris Wright issued an *emergency order* May 23 that seeks to keep Consumers Energy's 1,560-MW J.H. Campbell coal plant in West Olive, Mich., running past its May 31 retirement date.

"Today's emergency order ensures that Michiganders and the greater Midwest region do not lose critical power generation capability as summer begins and electricity demand regularly [reaches] high levels," Secretary Wright said in a statement. "This administration will not sit back and allow dangerous energy subtraction policies to threaten the resiliency of our grid and raise electricity prices on American families."

The Office of Cybersecurity, Energy Security and Emergency Response issued the order under Section 202(c) of the Federal Power Act, which is in accordance with President Trump's Executive Order Declaring a National Emergency. (See *Trump Seeks to Keep Coal Plants Open, Attacks State Climate Policies*.)

Section 202(c) effectively is a federal backstop for reliability-must-run deals to keep power plants needed for reliability open, overruling environmental laws in the process. Recently, it has been invoked for brief periods. The Trump administration's order signals a more aggressive use of the authority.

The rule was *used* in 2005 to keep power flowing to the White House by preventing the closure of coal plant across the Potomac River in Alexandria, Va.

Why This Matters

FPA Section 202(c) effectively is a federal backstop for reliability-must-run deals to keep power plants needed for reliability open, overruling environmental laws in the process. The Trump administration's order signals a more aggressive use of the authority.

Consumers signed a deal with Michigan regulators in 2022 that it would stop burning coal by the end of 2025. (See *Michigan PSC Oks CMS Plan to End Coal Use by 2025*.)

"We're officially retiring our J.H. Campbell Complex beginning in early 2025," the utility's website said. "This will allow us to get closer to end coal use by 2025, lower our carbon footprint and add more renewable energy for us to deliver."

DOE cited NERC's recent Summer Reliability Assessment that listed the Midcontinent ISO (and several other regions) at an elevated risk for outages this summer due to a narrow reserve margin. The order declares an emergency on the grid to keep the J.H. Campbell plant open.

"Its retirement would further decrease available dispatchable generation within MISO's service territory, removing additional such generation along with the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024," the order said.

The retirement was in MISO's and Consumer's summer forecasts, as was a new 1,200-MW natural gas plant it purchased, which expected sufficient capacity to meet peak demand, the order said.

"For the duration of this order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers," the order said. "Following conclusion of this order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant."

The secretary's order directs Consumers to file waivers needed for compliance with FERC. It also directs the plant to follow environmental laws while producing power. ■

House Passes Reconciliation Package that Would End Energy Tax Credits

By James Downing

The House of Representatives narrowly passed President Donald Trump's "One, Big Beautiful Bill" that would extend tax cuts for individuals and render energy tax credits effectively useless.

After meeting through the night, the House passed H.R. 1 by a vote of 215-214 in an early-morning *vote* May 22. The Senate has yet to take up the package, but the bill is being passed through reconciliation, meaning it is exempt from the filibuster.

"Today, the House has passed generational, nation-shaping legislation that reduces spending, permanently lowers taxes for families and job creators, secures the border, unleashes American energy dominance, restores peace through strength, and makes government work more efficiently and effectively for all Americans," House Speaker Mike Johnson (R-La.) said in a statement.

The bill would sunset tax credits for renewables, storage and nuclear earlier than current law and add new restrictions to foreign components. (See *House Committees Mark up Budget Bill that Guts Energy Tax Credits*.)

It would also require that renewable and storage projects be completed — rather than begin construction — by the end of the year to qualify. Nuclear plants were spared this provision. (See related story, *So far, Nuclear Energy Credits Remain in Reconciliation Bill*.)

American Clean Power Association CEO Jason Grumet called on the Senate to reject the House's hardline approach to winding down tax credits, which were last updated by the Inflation Reduction Act of 2022, passed by Democrats using reconciliation.

"This morning, the House voted to immediately end the clean energy tax incentives that provide economic growth, good-paying jobs and low-cost electricity to millions of Americans," Grumet said in a statement. "By a margin of one vote, the House voted to retreat in our competition with China for manufacturing jobs and to weaken our technology sector in the global race for digital dominance."

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

Why This Matters

Clearing the House is a major step forward for the legislation, but provisions could change in the Senate.

American Council on Renewable Energy President Ray Long said growing demand for electricity requires generation of all kinds, and the bill would set back Trump's goal of reliable and affordable power.

"ACORE is committed to working with Congress and President Trump to make any improvements to this legislation and help them deliver on his promise to slash energy costs for Americans by 50%," Long said in a statement. "It's time to achieve American energy dominance across all technologies."

Advanced Energy United also argued that the bill would lead to reliability issues and raise prices.

"At a time of growing demand, economic uncertainty and fierce competition, we need smart, certain tax policies that are pro-growth," CEO Heather O'Neill said in a statement. "Last year alone, the advanced energy industry added over 50 GW of new capacity to the U.S. grid, generated an estimated $400 billion in domestic revenue and led the way with critical investments in energy storage, nuclear power and American manufacturing. This work must continue without delay to power the U.S. economy and to keep the lights on across the country."

The Solar Energy Industries Association also called on the Senate to change the legislation, with CEO Abigail Ross Hopper saying that deploying solar and storage is the "only way" the grid can keep up with growing demand.

"If this bill becomes law, America will effectively surrender the AI race to China, and communities nationwide will face blackouts," Hopper said in a statement. ■

Power System's Shifting Direction Highlighted at Energy Future Forum

By James Downing

FERC Chair Mark Christie speaks at the Energy Future Forum at the U.S. Chamber of Commerce headquarters on May 19. | *© RTO Insider LLC*

WASHINGTON — President Donald Trump's policies and the growth in demand from data centers and other new customers have changed the trajectory of the power system, speakers said May 19 at the Energy Future Forum, hosted by RealClearEnergy and the U.S. Chamber of Commerce.

"Demand is going up, but we're losing exactly the dispatchable resources that we need," FERC Chair Mark Christie said. "Particularly we're losing coal resources, and we're losing some gas, and over the last 20 years, we've lost nuclear."

The "reality that is tracking us down" is demand rising from data centers, manufacturers and other sources, while too many resources are retiring.

"And they're not being replaced with sufficient dispatchable capacity," Christie said. "So, it's just arithmetic. You don't need to be a Ph.D. in math to see the numbers are not adding up."

FERC's main role in dealing with that situation is regulating wholesale markets, which cover about three-fourths of the customers in the country, he said. It has a larger role in restructured states that have left their generation investment decisions largely up to those markets. "A lot of states effectively delegated their ability to determine their generation mix to these FERC-regulated markets."

A key role for FERC as a regulator is to be a truth teller about the reliability issues facing those markets, he continued. The commission is holding a two-day *technical conference* on June 4 and 5 to detail the status of resource adequacy across those markets.

"One of the things that I really worry about is that we kind of continue to march down the path of removing diversity from the grid," NERC CEO Jim Robb said.

While plenty of forensics remain to be done to determine the causes of the massive blackout in Portugal and Spain on April 28, Robb said a major factor in its size was the lack of traditional generation operating on their grid at the time, with 74% being inverter-based resources (solar, wind and batteries).

The rest was hydro and natural gas, which provided some inertia that can help cushion the grid against frequency disturbances, but ultimately it was the "wall of inertia" from the French nuclear fleet that stopped the blackout's growth, Robb said. Generators from across the Strait of Gibraltar in Morocco provided black start to bring back Iberia's grid within a day.

Why This Matters

Renewables and batteries are still growing, but the new goal of meeting demand levels not seen in decades is causing the industry to focus on dispatchable generation, which for the immediate future means more natural gas generation.

While traditional generation helped bail out that blackout, Robb said some new inverters are capable of grid forming, and other technologies like flywheels and synchronous condensers can provide vital ancillary services too.

"Batteries can also kind of help on frequency response," Robb said. "We're seeing that in Texas right now. And the solar-battery combination is really a killer summer generating resource."

Solar and batteries are a great pairing in regions with a lot of sunshine, with the best in the U.S. being Texas and the Desert Southwest. But the combination is not nearly as effective in the winter, only helping balance the grid a little.

"It's kind of a horses-for-courses thing: Any one resource can be good for one thing, but not everything," Robb said. "And that's true of gas; it's true of coal; it's true of nuclear."

Batteries can also help address the main issue of growing demand by helping balance the transmission system and adding flexibility to data centers without the emissions associated with more standard diesel backup generation, Eolian CEO Aaron Zubaty said. He brought up a Duke University study that has been making waves since its release this winter. (See *US Grid Has Flexible 'Headroom' for Data Center Demand Growth*.)

"We're building a 2-GWh site right now in Texas, next to a retiring coal power plant," Zubaty said. "We're finishing multiple 1-GWh sites right now in Portland, Ore. These are designed to be locations so that you don't need to rebuild transmission, and so that the grid runs more efficiently."

Batteries can help all kinds of large, inflexible loads connect more easily to the grid by running during peak times, avoiding the need to expand the grid in order to keep them running. On top of data centers, Eolian is also working on projects with large industrial sites like aluminum smelters to accomplish the same thing, Zubaty said.

Eolian is focused on lithium-ion batteries because they have become commoditized, and their affordability is making longer-duration batteries more economic.

"When you can do eight and 10 hours — where, by the way, we can turn it on in 250 milliseconds — that is a very unique asset on the energy grid for all the reasons we heard earlier about reliability," Zubaty said. "The combination of many, many hours of reliability plus instant response has pretty much never existed in the history of the grid at this scale."

While renewables and storage are continuing to grow, the flow of capital in North America has shifted away to natural gas and other traditional resources, 1PointSix CEO Terrence Keeley said. And it's not just the U.S.

"It will be very interesting to watch the metamorphosis of Mark Carney as [Canadian] prime minister from central banker. We're going to find that he's much more interested in developing Canadian tar sands than perhaps he had been as a banker," Keeley said.

Even with the Wall Street money flowing increasingly to other resources, renewables are continuing to grow. Keeley criticized language in this year's budget bill on clean energy tax credits. (See *House Committees Mark up Budget Bill that Guts Energy Tax Credits*.)

"One of the big problems we're having amongst Republicans is how quickly these incentives are going to be removed for renewables," Keeley said. "Turns out they fought against the [Inflation Reduction Act] when it was going into law, but they're now fighting to not take it off too quickly. St. Augustine needs to be called out, in light of our new pope: 'God, grant me chastity, but not yet.'"

GE Vernova Gas Power CEO Eric Gray speaks at the Energy Future Forum on May 19. | *© RTO Insider LLC*

GE Vernova Gas Power CEO Eric Gray has seen firsthand the rise in demand for the turbines it manufactures as industrialization, data centers and electrification are all growing its orders.

"Given the fact that gas turbines can be installed in a relatively short period of time versus some of the other technologies out there, gas is a good solution to what we need today," Gray said.

As recently as late 2023, GE Vernova could have fulfilled an order for a turbine in 12 to 18 months, but if one is ordered today, it will not be delivered until 2028. The company is responding to the uptick in demand with $600 million overall invested this year, including $300 million in gas.

Part of that money is going is going to its manufacturing plant in Greenville, S.C., where it is installing 500 new pieces of equipment in a bid to make the facility efficient and capable of producing more turbines. The investments are expected to grow the firm's production capacity by 35%, Gray said.

That domestic demand has been constant for about 12 months, but before that, the firm was seeing more orders from Southeast Asia, Taiwan and Saudi Arabia, he said. Another wrinkle in the picture is Trump's tariffs, but Gray said that they are not having much of an impact on business.

"If you fast forward to tariffs, as we said publicly, around 5% of our spend comes from China, Mexico and Canada," he added. "It's definitely not immaterial, but it's something that we're working our way through. The conversations we're having with our customers today — obviously, having an increase in price changes the economics that they thought they were underwriting, but the fact of the matter is that the demand is still there. We need the electrons, so they're being somewhat accepting of the tariffs and the price increases that they're seeing as a result." ■

U.S. Hydropower Projected to Bounce Back from 2024 Slump

EIA also Forecasts More Power from Solar, Coal in 2025

By John Cropley

Federal analysts expect U.S. *hydropower generation to increase* 7.5% over 2024 totals, which were the lowest in at least 14 years.

The U.S. Energy Information Administration said in its May Short-Term Energy Outlook that the 259.1 billion kWh projected this year still would be 2.4% below the 10-year average and would constitute 6% of the nation's power generation.

The projections are strongly influenced by conditions in the West Coast states, as roughly half the nation's hydroelectric generating capacity is in Washington, Oregon and California.

Precipitation conditions have been mixed there and in the Rocky Mountain region.

More precipitation than normal was recorded since October in northern California and eastern Washington, and some areas of Oregon saw record levels of precipitation. But Montana, Idaho and other parts of Washington and California saw below-normal precipitation from October through April.

2025 hydropower output in the Northwest and Rocky Mountain region is projected at 125.1 BkWh — 17% more than 2024 but 4% less than the 10-year average.

By contrast, 28.5 BkWh of hydropower generation is projected in California, 6% less than last year but 15% more than the 10-year average.

As of April 1, most major reservoirs in California were above the historical average for that date — two of the largest, Shasta and Oroville, stood at 113% and 121%, respectively.

Snowpack conditions were above normal in the northern Sierra Nevada region and below normal in the central and southern Sierra regions as of April 1. Higher-than-average temperatures brought the snowpack to well-below-average levels for all three regions by May 1.

Why This Matters

Precipitation patterns are among the variables affecting the U.S. power generation mix in 2025.

Other Generation

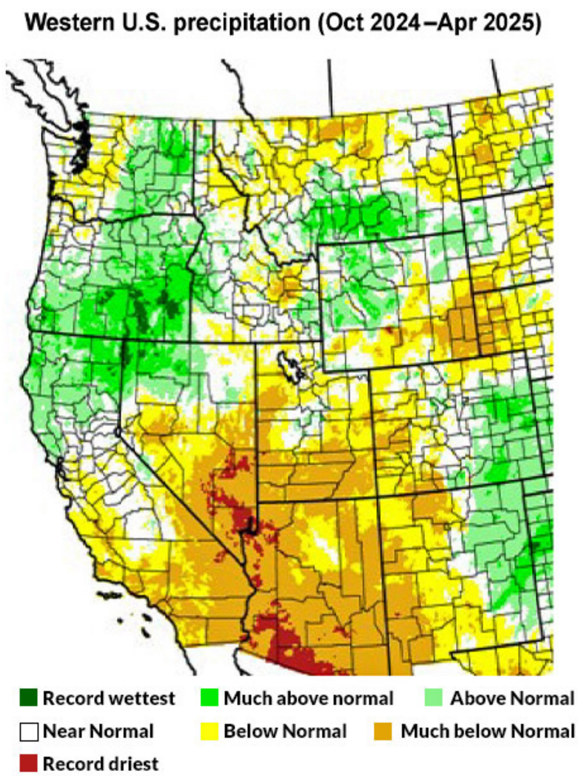
More broadly, the EIA's *May Short-Term Energy Outlook* forecasts that U.S. electrical power generation will be 2% higher in 2025 than in 2024, and then 1% higher in 2026.

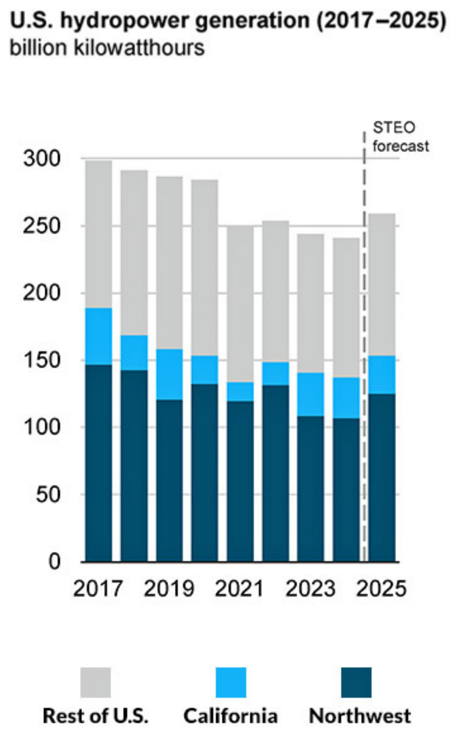
EIA predicts that natural gas will remain the largest single fuel for electrical generation. But it expects 2025 output from gas-fired plants to decline 3% year over year due to gas prices, which are forecast to be 63% higher on average than in 2024.

This — combined with recently relaxed emissions regulations on coal-fired plants — will lead to a 6% increase in generation from coal, EIA predicted.

EIA said about 5% of U.S. coal-fired generation facilities had been slated for retirement in 2025, most of them at the end of the year, which could reduce generation from coal by 9% in 2026. However, the agency also said President Donald Trump's policy changes in favor of coal could alter these retirement strategies, adding a degree of uncertainty to the forecast.

Utility-scale solar generation is expected to jump 34% in 2025 and 18% in 2026, EIA said, bringing total installed capacity to 180 GW by the end of next year and providing another limiting factor on natural gas-fired generation. ■





The U.S. Energy Information Administration is projecting greater hydroelectric power generation in 2025 than in 2024, due to precipitation levels. | EIA

EBA Event Examines History of Electricity Demand as Industry Tackles New Wave

By James Downing

Why This Matters

The industry has met major growth in demand before, even if the return of demand growth is new to many working today.

WASHINGTON — The return of rapid load growth is still a relatively new phenomenon for the power industry, but demand has seen such cycles several times before, speakers said at the *annual half-day meeting* of the Energy Bar Association's Electricity Steering Committee.

Electricity started off as a niche product, with fully distributed power generators serving mansions and some industrial customers in the late 19th and early 20th centuries, recalled Hannah Wiseman, professor of law at Penn State University.

Appleton, Wisc., was home to the first grid in the country, with a hydropower dam serving multiple homes and the lights dimming as water flow slowed.

At first industry preferred distributed power, and residential customers only used electricity for lights, but that expanded to new products like electric clocks. It was not until World War I that industrial use took off and the grid as we know it started to be patched together, Wiseman said.

"We start to see more centralization, and we start to see more federal involvement, which means we also start to see more public involvement in power," Wiseman said. "So the War Department in World War I became directly involved in determining where the electricity needed to be generated most."

The department helped to wring efficiency out of the grid by determining when coal power needed to be dispatched due to hydropower not producing enough to meet demand, she said.

Under the New Deal, electricity service started expanding to more rural areas, such as through the Tennessee Valley Authority. Then World War II and its demands on industry made the backbone transmission system developed in the 1930s a valuable investment. Demand surged during the war as industry built massive fleets of airplanes that needed aluminum, she said.

"Historians say that that previous build-out that was in the 1930s was viewed as an overbuild," Wiseman said. "Private industry said: 'Will the rural customers … use this much power? Do we need all this transmission?' It turned out to be quite important."

After the war came the golden age of the investor-owned utility, when demand grew by 416% between 1949 and 1969, with residential demand growing even faster, at 540%, Harvard Law School's Ari Peskoe said.

Ronald and Nancy Reagan sell the benefits of electricity for General Electric back in the early days of television. | *General Electric Theatre*

There was a massive housing boom after the war, and the electric industry tried to maximize their individual power demand.

"If you can get a what was called 'a total electric home' at the time, where it's using electricity for heat, hot water for cooking; that's a massive increase in the amount of electricity that house is going to consume," Peskoe said.

From 1970 to 1990, demand grew by 100%. A survey by the Department of Energy in 1979 found homes that only had electricity used three times the amount of power as homes that had another fuel such gas or oil, Peskoe said. The industry tried to maximize those total electric homes with direct financial incentives and via advertising in the early days of television.

"There's some great commercials there," Peskoe said. "You can see Ronald and Nancy Reagan *promoting* all sorts of electricity use in the home."

The rapidly growing demand coupled with efficiencies from new, larger power plants meant that adding capacity to the grid lowered costs for everyone, Peskoe said. That led to similarly rapid growth in power demand, which had to be managed either by taking turns building new plants or working together on joint projects.

"Consistent with Section 202(a) of the Federal Power Act, the Federal Power Commission was focused on encouraging utility coordination at the bulk power system," Peskoe said. "So, for instance, in 1964, it publishes a two-volume national power survey, and the theme of that is basically the benefits of coordinated growth. That is, utilities ought to be interconnecting more. They ought to be trading more. There ought to be more joint planning, even potentially joint dispatch."

That all should sound familiar to anyone who knows the FPC by its newer name, FERC, and while the commission, states and industry are all grappling with demand growth and the need to meet it now, the days of power too cheap to meter are over.

Former FERC Commissioner Philip Moeller, who recently left the Edison Electric Institute, started at the commission in 2006 when the economy was booming, but then the 2008 financial crisis hit. That contributed to low demand growth, but it also led central bankers to cut interest rates to zero in advanced economies.

"We had a period of extraordinary monetary policy where interest rates were basically zero for almost 10 years," Moeller said. "I mean, that's an exaggeration, but not too far off."

In a capital-intensive industry where investments last for decades, the cost of borrowing money is important, Moeller said. Now those zero interest rates are a thing of the past, but when it comes to the electric industry, the regulatory framework is also vitally important, said Moody's Ratings Vice President Jairo Chung. About 50% of the credit risk in Moody's analyses comes from the regulatory side of things.

"We look at the judicial underpinning of the regulatory framework where the authorities operate," Chung said. "So, this could be state regulation, but also federal-level regulation, and we also look at the consistency and predictability of the law."

Other ratings agencies assign utility credit scores to states, but Moody's is instead more granularly focused on how specific utilities work within their state frameworks because that can vary across firms under the same jurisdiction, she said.

Maryland People's Counsel David Lapp criticized those agencies that do rank states because he has found them to be arbitrary, with different agencies scoring his state very differently.

"My primary concern as the customer advocate is regulators overusing or being oversensitive to how a rating agency may categorize the state as a whole," Lapp said. State rankings can change, with no impact on a utility's credit rating, which is more important to investors than ratepayers, he said. ■

BPA Approves $700M Plan to Boost Columbia Generating Station Output

Project Plus Other Improvements to Uprate Northwest's Only Nuke by 186 MW by 2031

By Robert Mullin

Why This Matters

The project, plus other improvements, will increase CGS' output by 186 MW by 2031 and reduce BPA's need to procure solar and wind resources.

The Bonneville Power Administration has approved a $700 million plan to increase the output of the Pacific Northwest's only commercial nuclear plant by 162 MW by 2031.

BPA said May 22 that it approved implementation of an extended power uprate (EPU) project for the 1,207-MW Columbia Generating Station (CGS) it publicly proposed in April. (See *Northwest's Only Nuclear Plant Could Get Uprate*.)

The federal power agency said also that CGS will gain an additional 24 MW of capacity from a series of energy efficiency upgrades made during the plant's 2027, 2029 and 2031 refueling cycles, bringing the total increase to 186 MW.

Located near Richland, Wash., CGS is owned and operated by Energy Northwest, a consortium of Washington utilities, but BPA markets the energy produced by the plant and covers its costs, which are included in the revenue requirements of the agency's power services rate structure.

"This is a great value for ratepayers in the Pacific Northwest," BPA Administrator John Hairston said in a statement. "Upgrading an existing resource to provide additional reliable energy will help BPA keep pace with its customers' growing electricity needs and keep rates low."

"We applaud BPA for its decision to approve this project and for its strategic vision in advancing our region's future with additional, reliable capacity that nuclear energy can provide," Energy Northwest CEO Bob Schuetz said. "Their leadership in supporting this initiative underscores a commitment to affordable and carbon-free electricity for the Northwest region, including our public power member utilities and their customers."

BPA and Energy Northwest said the EPU will increase electrical output at the plant by upgrading and replacing key pieces of equipment, including turbines, heat exchangers and the plant's generator. The process will also involve 30 individual upgrades focused on increasing the size of pumps and motors.

During an April 8 meeting to discuss the proposed uprate, a BPA representative said the agency's resource program includes the CGS EPU in its least-cost portfolio for meeting future customer needs, reducing the amount of new solar and wind capacity it would otherwise need to procure. ■

Columbia Generating Station | *Energy Northwest*

California's 'Pathways' Bill Heading to Senate Floor

Questions Remain About Status of Previous Amendments

By Robert Mullin

A California bill to implement the West Wide Governance Pathways Initiative's Step 2 proposal is headed to the floor of the state Senate after being approved by the body's Appropriations Committee May 23.

The committee voted 4-1 to move *Senate Bill 540* — known as the "Pathways" bill — out of the "suspense" process, part of a normal procedure in which bills are examined for their fiscal impact before being advanced to the floor for a second reading and debate.

But questions remain about the exact content in the bill, especially related to amendments.

SB 540 authorizes CAISO to 1) transfer its state-backed governance authority over its Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM) to the new, independent "regional organization" (RO) being developed by the Pathways Initiative; and then 2) join the RO as a participating member. (See *Pathways 'Step 2' Bill Sets Conditions for EDAM Governance*.)

In late April, the Senate's Judiciary Committee amended the bill to include several provisions intended to shield California's environmental and energy policies from interference by the Trump administration through any potential backdoors opened by CAISO's participation in the RO. (See *California Lawmakers Seek to Trump-proof Pathways Initiative Bill*.)

Key among those amendments is a provision allowing the California Public Utilities Commission to direct the state's investor-owned utilities to exit the RO if the new body's market rules — or other public policies — become "detrimental to California consumers;" the state's renewable portfolio standards are "held invalid by [a] reviewing court on claims of impermissible discrimination;" or Trump or future presidents use emergency powers to require California to subsidize fossil fuels.

Another amendment would prevent the RO from establishing capacity markets, which California consumer advocates worry would be used to support coal-fired generation the Trump administration is seeking to incentivize.

According to one source not authorized to speak for their organization, the amendments have rankled some Pathways supporters, who are concerned the changes needlessly complicate the bill's original intent.

During a May 9 press briefing after the Bonneville Power Administration released its long-awaited day-ahead market decision in favor of Markets+, BPA Vice President of Bulk Marketing Rachel Dibble said the amendments "continue to erode the independence that was even in the initial bill, which we did not find to be superior to Markets+." (See *Debate Lingers After BPA Day-ahead Market Decision*.)

But the precise language of the bill emerging from the Appropriations Committee still is unclear.

While the bill tracker on the California Legislature's website indicates the committee voted with the recommendation of "do pass as amended," multiple sources familiar with the legislative process said the bill could have been further altered in committee, with the previous amendments revised or potentially stripped out — although Appropriations amendments typically deal with fiscal matters.

"Any bill that costs money or would bring in more than a certain amount of money is automatically moved to the suspense file in Appropriations. It can definitely be amended there," according to a source familiar with California's legislative process.

That issue will become clearer when the Legislature prints and posts the next version of the bill, likely May 27, according to one source. ■

California State Capitol | *Shutterstock*

Arizona Utilities Explore Expanded Use of Nuclear

APS, TEP, SRP Seeking DOE Funding for SMR Projects

By Elaine Goodman

Arizona utilities are seeking U.S. Department of Energy funding to help plan for additional nuclear power facilities in the state.

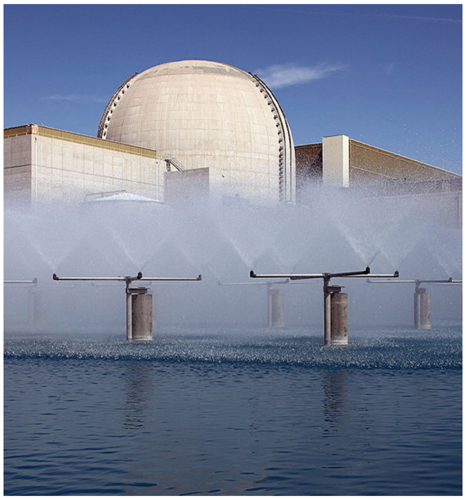
Representatives from Arizona Public Service (APS), Tucson Electric Power (TEP) and Salt River Project (SRP) discussed their plans May 21 during an Arizona Corporation Commission workshop on advancing nuclear power generation in the state.

APS is leading the effort, working in partnership with TEP and SRP. The goal is to select a site for a future nuclear facility and submit an early site permit application to the Nuclear Regulatory Commission, according to Brian Cole, vice president for resource management at APS.

In evaluating sites, the utilities will consider the availability of land, water, transmission infrastructure and workers. Coal-fired power plant sites are one possibility, as are the site of the Palo Verde nuclear generating station and other locations.

To help with the planning, the utilities have applied for funding through the Generation III+ Small Modular Reactor *program* in the DOE's Office of Clean Energy Demonstrations.

The utilities are applying for funding in the "fast follower" category, which will provide up to $100 million to address hurdles the U.S. nuclear industry has faced in areas such as design, licensing, supply chain and site preparation. Awardees must match the DOE funding.



As Arizona utilities plan for new nuclear power facilities in addition to the Palo Verde Generating Station, the availability of water is one issue they'll need to address. | *Arizona Public Service*

DOE opened the funding opportunity in October and reissued the solicitation in March. The Arizona utilities submitted a revised application in April. They expect a decision by the end of the year.

Small modular reactors could provide reliable power for energy-intensive applications such as industrial uses, artificial intelligence and data centers, DOE said in a March announcement. SMRs offer flexible deployment due to their compact size and modular design, the agency added.

"Light-water small modular reactors could also leverage the existing service and supply chain supporting the country's current fleet of light-water reactors, helping speed up the near-term deployment of new nuclear reactors," DOE said.

Technology Options

Despite the DOE grant's focus on Generation III+ SMRs, the Arizona utilities are remaining open for now to different types of nuclear technology, Cole said.

"We also want to make sure we keep the door open for both SMRs and large-scale nuclear," Cole told commissioners.

An early site permit (ESP) from the NRC may consider a range of technologies, according to Tom Cooper, SRP's senior director of future system assets and strategy. The ESP, which is a voluntary permit, is a way to reduce the risk surrounding a nuclear project, he said.

An early site permit "does not authorize construction or operations, but it is a significant de-risking factor, because it gives you a very strong indication that the … NRC finds that site suitable to host nuclear."

Palo Verde's Status

APS operates the 4.2-GW Palo Verde nuclear power plant, the largest power producer on the Western grid. It shares ownership of Palo Verde with six utilities: SRP, El Paso Electric, Southern California Edison, Public Service Company of New Mexico, Southern California Public Power Authority and the Los Angeles Department of Water and Power.

Palo Verde is the only nuclear plant that's not next to a body of water. The facility uses reclaimed wastewater.

"We continue to evaluate water strategy at the station," said John Hernandez, vice president of site services at Palo Verde. One idea is to use lower-quality wastewater.

The first of Palo Verde's three reactors is set to mark 40 years of operation in June. In 2011, the NRC granted Palo Verde a 20-year license extension that runs to 2047. An application for an additional 20-year license extension is being considered, with a target date for approval of 2029, Hernandez said.

Although APS has the largest ownership stake in Palo Verde, at 29%, followed by SRP at 20%, ownership shares in a new nuclear facility would be subject to negotiation, Cole said.

Commissioner Lea Marquez Peterson asked whether California utilities might want to be involved in a new Arizona nuclear facility, a move that might help reduce risk for the Arizona utilities.

California entities "don't have that political openness to placing a new nuclear plant in their state, but seem to be open to keeping the energy," she said.

Cole said the current focus for a potential nuclear project is Arizona's needs.

"We're looking at this right now as an Arizona project, but that doesn't mean … that there won't be additional partners in the future," he said. ■

Why This Matters

Arizona utilities could be at the forefront of a revived use of nuclear power in the U.S. if state regulators give approval.

CAISO Postpones EDAM Congestion Revenue Decision

Decision now Expected in June

By David Krause

CAISO has delayed its final decision on how to allocate congestion revenues in its Extended Day-Ahead Market (EDAM) after receiving comments from stakeholders asking for more analysis.

CAISO planned to vote on its draft final proposal in late May but decided to hold off until June. Adjusting the proposal's planned approval date has "allowed us to further explore additional enhancements suggested by stakeholders," said Anna McKenna, CAISO vice president of market design and analysis, at a May 20 WEM Governing Body meeting.

The congestion revenue initiative is a top priority for CAISO in 2025. The organization received comments from PacifiCorp that questioned the way congestion revenues will be allocated in the proposed EDAM design. The primary concern is whether certain congestion revenues should be allocated to the balancing area in which the congestion costs accrued, or to the neighboring EDAM balancing authority area where the transmission constraint is located, specifically in cases in which parallel — or loop — flows occur.

On May 19, CAISO published a revised draft final proposal, which fine-tunes the allocation of parallel flow congestion revenues "based on the exercise of eligible firm point-to-point and Network Integration Transmission Service and Open Access Transmission Tariff transmission rights."

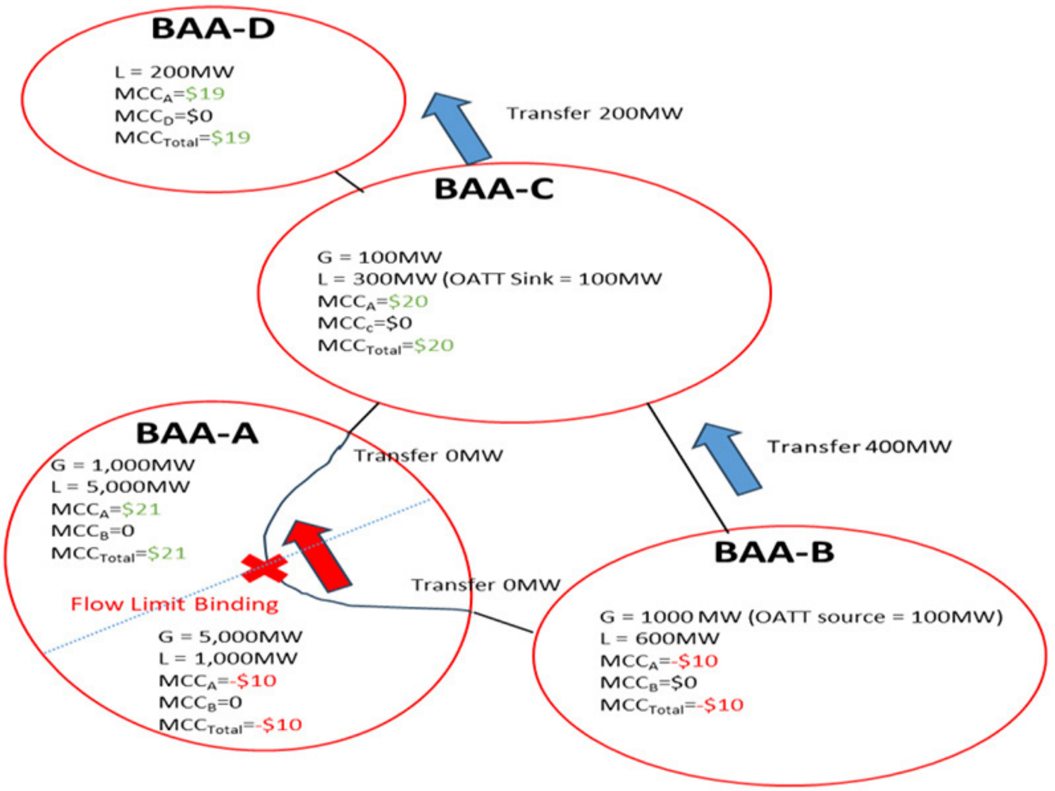
The revised draft provides details about congestion revenues that are not received under the current design for the EDAM entity. Any remaining parallel flow congestion revenue accrued because of a transmission constraint in a neighboring EDAM balancing area would be allocated to the area where the binding transmission constraint is located, CAISO wrote.

The revised draft is consistent with FERC requirements that say congestion revenues accruing internal to an EDAM balancing area because of an internal transmission constraint are allocated fully to that balancing area — i.e., where the transmission constraint is located, CAISO wrote.

Why This Matters

CAISO's decision about how congestion revenues will be allocated in EDAM has been a top priority for the organization in 2025.

"Stakeholders continued to note the concern that the proposed design in the near term may incent self-scheduling by transmission customers in order to receive a congestion hedge, a 'use it or lose it' concept to the exercise of transmission rights," CAISO said in the draft. "In this context, stakeholders indicated broad support for an economic bidding enhancement to enable parallel flow congestion revenue allocation for balanced cleared market schedules based on economic bids, not only self-schedules."



An example of parallel flow revenue allocations under the revised proposal. | *CAISO*

The revised proposal includes an example of a load event that shows how much money would be distributed to four balancing areas: BAA-A, BAA-B, BAA-C and BAA-D. In the example, the market footprint net settlement is an over-collection in congestion revenue of $135,800. Under the current EDAM design, all of the congestion revenue is allocated to the BAA where the constraint is modeled, CAISO wrote. However, under the revised draft, the congestion revenue associated to balance OATT self-schedules is allocated to the EDAM entity where OATT rights are exercised.

CAISO will hold a stakeholder meeting on the revised final draft proposal May 27, with comments due by June 2. CAISO plans to publish a final proposal June 6. ■

CAISO Approves $4.8B Transmission Plan to Support 76 GW of New Capacity

San Francisco Bay Area Projects Receive Largest Piece of Pie

By David Krause

CAISO's Board of Governors on May 22 approved the ISO's 2024/25 transmission plan to build out 31 new projects in the region over the next eight to 10 years.

Of the 31 approved projects valued at $4.8 billion, 28 are for reliability purposes for $4.6 billion. By 2039, California will need 76 GW of additional capacity to meet increasing building electrification and electric vehicle loads, CAISO wrote in the plan.

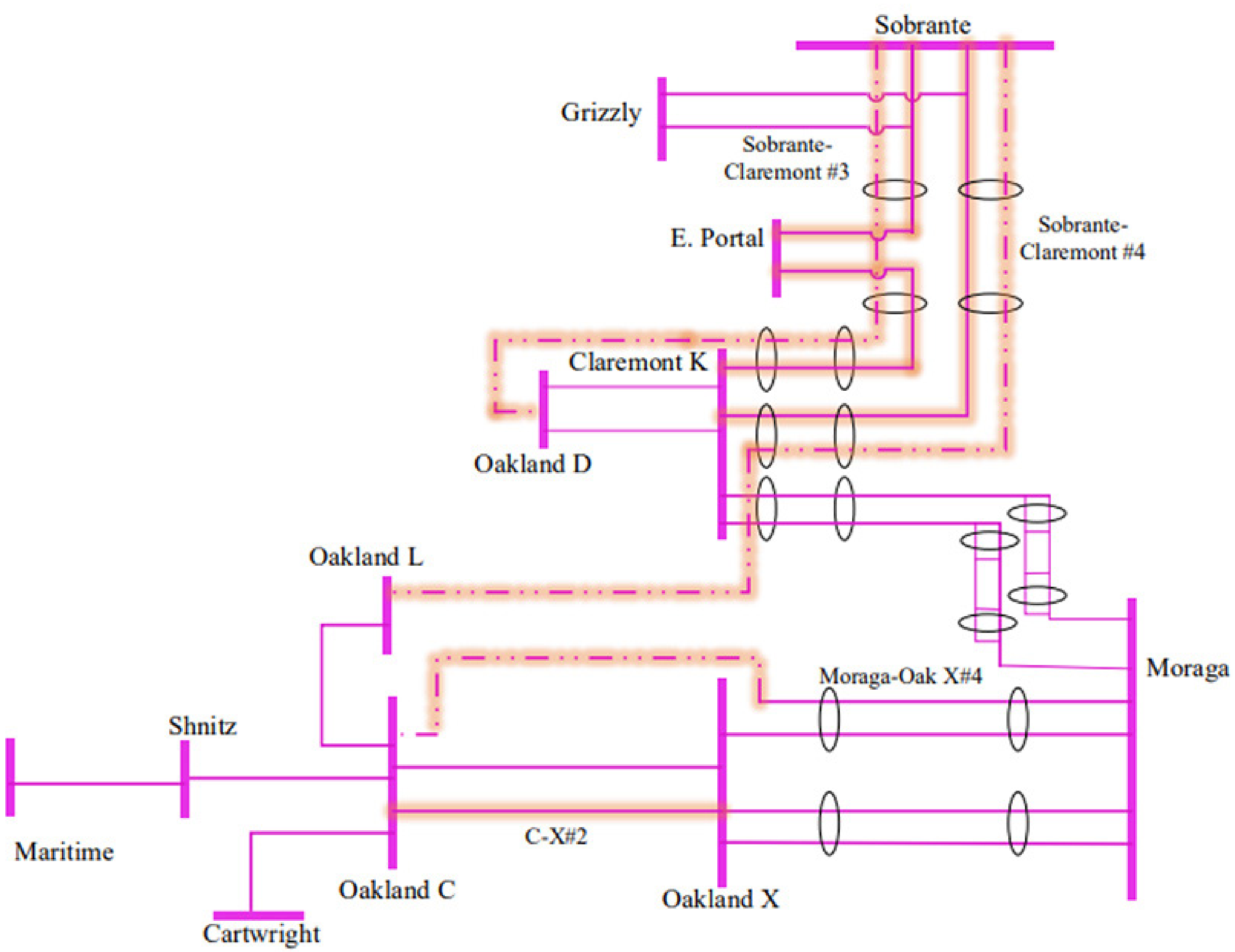
The plan's most expensive project is the North Oakland Reinforcement Project, estimated at $1.1 billion and with an online date by 2032. The project includes the Port of Oakland, which is experiencing rapid load increase due to industrial and commercial growth, EV charging and electrification loads.

The project is meant to meet increasing demand without relying on local Oakland thermal generation units, CAISO wrote in the plan. Demand is forecast to increase from 377 MW in 2024 to 458 MW by 2039 in the region. CAISO and Pacific Gas and Electric should attempt to accelerate the completion of the project prior to 2032, Teri Dean Alderson, assistant general manager at Alameda Municipal Power (AMP), said in comments to CAISO.

Why This Matters

CAISO's transmission plan in large part will determine how California's grid will accommodate the resources needed to meet growing electrification and EV loads.

The second-most expensive project in the plan is the $700 million Greater Bay Area 500-kV Transmission Rein-



A schematic of the North Oakland Reinforcement Project | *CAISO* forcement project, which has an online date of 2034. The area could have a deficiency of about 5,000 MW by 2039, which significantly surpasses the available transmission resources and internal generation capacity, CAISO said in the plan. The forecast supply shortage is caused by the potential loss of two of the three 500/230-kV transformer banks at Metcalf or loss of the two 500-kV sources to Metcalf and Moss Landing substations, CAISO said.

About $290 million of the remaining funding is allocated for three policy-driven transmission projects. Policy-driven transmission projects enable the grid to support local, state and federal directives, with most of these projects focused on meeting California's renewable energy goals, CAISO said.

From a systemwide resource assessment, CAISO is going into a period of greater uncertainty as load growth continues to accelerate, Neil Millar, CAISO vice president of transmission planning and infrastructure development, said at the May 22 ISO Board of Governors general session meeting.

"Not only are the peak loads growing, but our load factor and winter peak loads are growing, which is a success of building and transportation electrification," Millar said. "Those are creating additional challenges that the state agencies are taking into account."

Having more transmission project options is important because "we don't know what things are going to look like four years from now [at the federal level]," Millar said. However, CAISO must also follow state policies and cannot afford to let transmission projects be a barrier to achieving state policy goals, he said.

At the same time, CAISO should consider the risk of policy changes affecting expensive transmission projects, such as two transmission projects in the North Coast region, which are to support future offshore wind power in Humboldt County, Millar said. Last week, CAISO selected Viridon to build these future OSW transmission projects for up to $4.1 billion over the next eight to 10 years. (See *CAISO Chooses Viridon to Develop Humboldt OSW Transmission Projects*.)

The projects were designed to be the right first step, but CAISO recognizes that the resource requirements for the lines can grow beyond their initial design, Millar said.

"We were also very clear in bidding those projects that there is inherent uncertainty in those resource types and as a result those projects have a higher risk of potential cancellation," Millar added.

The transmission plan also emphasizes non-transmission alternatives, such as energy efficiency and demand response programs, renewable resources and energy storage systems. Battery energy storage has made up the vast majority of new resources in CAISO's region in recent years. As of April, more than 12,000 MW of battery storage capacity is online in CAISO's region, with an additional 15,000 MW planned to be available by 2028.

Stakeholders Applaud, Question Plan

In comments to CAISO, Caitlin Liotiris, principal at Energy Strategies, said one notable enhancement to this year's transmission plan is the additional transparency regarding CAISO's process for reserving deliverability for long lead-time resources.

"The [plan] specifies the long lead-time resources in the base portfolio and the amount of deliverability that is being reserved for them," Liotiris wrote.

However, staff with California Wind Energy Association (CalWEA) said CAISO's transmission plan "does not fulfill … CPUC's request to plan transmission for the 5.2 GW of in-state wind energy."

"CalWEA is primarily concerned with the Southern California Edison Northern and San Diego Gas & Electric study areas where wind development interest is currently the strongest," CalWEA staff said.

In the SCE Northern area, CPUC requested that CAISO plan for 564 MW of full capacity deliverability status. Of this 564 MW, only 100 MW has been awarded that status. CAISO must therefore plan for 464 MW, CalWEA staff wrote.

In next year's transmission plan, there will likely be a fairly heavy emphasis on load-growth related reliability projects as CAISO transitions to a higher long-term expectation of growth, Millar said. ■

Turlock Irrigation District to Join EDAM in 2027

Central Valley Utility Hopes to Build on WEIM Success

By Henrik Nilsson

California publicly owned utility Turlock Irrigation District has agreed to join CAISO's Extended Day-Ahead Market in 2027, the ISO said May 19.

Turlock's board of directors voted May 13 to allow the district to join EDAM in 2027, with the implementation agreement signed the following weekend. Turlock is a member of CAISO's Western Energy Imbalance Market (WEIM) and has saved $28 million since joining WEIM in 2021, CAISO stated.

Turlock provides irrigation water and electricity to more than a quarter million customers in California's Central Valley, according to the news release.

"[Turlock] has had tremendous success in the Western Energy Imbalance Market, and we are excited to build on this partnership and leverage the increased economic, reliability and environmental benefits of the Extended Day-Ahead Market," Brad Koehn, Turlock's general manager, said in a statement. "[Turlock]'s continued alliance with the California Independent System Operator will enable the district to continue our stellar track record of providing reliable, affordable power to its customers."

The announcement comes as the race for participants between SPP and CAISO is both heating up and winding down as the two entities prepare to launch their respective Western day-ahead markets.

SPP got a major win May 9 when the Bonneville Power Administration issued its long-awaited decision in favor of SPP's

Why This Matters

The Turlock Irrigation District's commitment to join CAISO's EDAM comes after SPP secured key commitments to Markets+ from the Bonneville Power Administration and Puget Sound Energy.

| Shutterstock

Markets+. Puget Sound Energy followed suit shortly after. (See *BPA Chooses Markets+ over EDAM* and *Puget Sound Energy Inks Agreement to Join Markets+*.)

Entities such as Xcel Energy subsidiary Public Service Company of Colorado, El Paso Electric and Tacoma Power have also committed to joining SPP's day-ahead market.

Meanwhile, PacifiCorp and Portland General Electric have agreed to begin participating in EDAM in 2026, with the Los Angeles Department of Water and Power and the Balancing Authority of Northern California set to join in 2027. (See *LADWP Gets Board's OK to Join CAISO's EDAM*.)

Additionally, BHE Montana, PNM, NV Energy, Idaho Power and Arizona G&T Cooperatives have indicated they are leaning toward EDAM as their preferred day-ahead market choice.

In CAISO's May 19 news release, the ISO said EDAM is built "on the proven track record of the WEIM."

"The Turlock Irrigation District has been a valued partner in the Western Energy Imbalance Market since 2021, and its decision to join the Extended Day-Ahead Market reflects the growing recognition of the markets' significant economic, reliability and environmental benefits," CAISO CEO Elliot Mainzer told *RTO Insider* in a statement. "As Turlock joins the community of EDAM entities, we are pleased with the continued expansion of the EDAM footprint and remain laser focused on achieving market go-live with PacifiCorp and Portland General in 2026." ■

CPUC Proposal Seeks to Blend RA, Clean Energy Procurement

Program Would Apply to California's IOUs, CCAs, Electric Service Providers

By Elaine Goodman

The California Public Utilities Commission has proposed a new framework that would take a "more programmatic approach" to load-serving entities' resource procurement requirements compared with the agency's recent practice of issuing procurement orders as needed.

CPUC released the proposal, called the Reliable and Clean Power Procurement Program (*RCPPP*), in late April. It is intended to cover procurement to meet both reliability needs and greenhouse gas emissions-reduction targets.

"The goals … are to build on prior procurement experience and to establish a clear and predictable set of long-term procurement requirements that will allow LSEs to better plan and implement their procurement of reliable and clean electric resources," the CPUC proposal stated.

CPUC staff held a workshop on the proposal May 16. RCPPP was also a topic of discussion during the California Energy Transition Summit in Sacramento on May 6-7, hosted by Infocast.

During the conference, Molly Sterkel, CPUC's electric market program manager, described RCPPP as a bridge between CPUC's resource adequacy program, which is focused on the availability of resources in CAISO markets, and the 10- to 15-year planning time frame of utilities' integrated resource plans.

Why This Matters

The goal of the proposed CPUC program is to enable California's load-serving entities to better plan for procurement of resources that together meet their state-mandated reliability and clean energy requirements.

She recalled CPUC's first procurement order to all LSEs, including investor-owned utilities, community choice aggregators and electric service providers, in 2019. That order, for 3.33 GW, was followed by a 2021 decision ordering a record-breaking 11.5 GW and a 2023 order for 4 GW. (See *California PUC Orders 4 GW of New Resources for Reliability*.)

"We were kind of tired of doing all those orders," Sterkel said. "We knew we needed to have a more durable approach."

CPUC staff issued proposals for a procurement framework in 2020 and 2022. The release of the current proposal was accompanied by a *summary of comments* on staff's 2022 options paper.

The CPUC is accepting opening comments on the proposal through June 5. Reply comments will be due June 26. Commissioners are expected to consider the proposal later in 2025.

RCPPP Requirements

RCPPP would apply to all LSEs under CPUC jurisdiction, including IOUs, CCAs and ESPs, but not publicly owned utilities.

The reliability portion of the RCPPP framework has four components: a determination of how many resources will be needed over a specified period, how much of the needed resources will be allocated to each LSE, reporting requirements and enforcement provisions.

The CPUC has proposed two options for reliability procurement.

Under both options, the Reliability Procurement Need (RPN) would be calculated based on the accredited capacity to meet the 0.1 loss-of-load expectation using marginal effective load-carrying capability, plus a 2.5% buffer.

In Option I, the scope of the need determination would include both new and existing resources.

Option II would adopt a rolling 10-year "new" resource vintage, defined as resources that came online or will come online no more than 10 years before the compliance year. This would give LSEs credit for proactive and early procurement, the proposal stated.

Molly Sterkel with the California Public Utilities Commission discusses the agency's proposed Reliable and Clean Power Procurement Program (RCPPP) during a California Energy Transition Summit in Sacramento on May 6. | © RTO Insider

For need allocation, both options would allocate RPN to each LSE using LSE-specific hourly load forecasts and each entity's *pro rata* share of load during critical hours.

On the GHG reduction side of the framework, CPUC staff have proposed a clean energy standard, which would be a percentage calculated to meet the electric sector GHG target. An LSE's allocated need would then be its retail sales forecast multiplied by the annual CES percentage.

California Senate Bill 100 of 2018 requires all electric retail sales to come from renewable energy and zero-carbon resources by 2045.

"How do you get to that 100% clean energy goal?" Sterkel said. "You can't just keep putting more and more clean capacity in the system. You also have to make sure that the energy mix of each of the entities gets us from here to the 100% clean energy goal."

Even with a new framework, procurement orders may still be needed to meet SB 100 objectives, according to a presentation during the CPUC workshop. ■

Texas RE: ESRs to Boost ERCOT During Summer

By Tom Kleckner

A "tremendous" growth in resources for ERCOT has resulted in a "significantly lower" probability for an energy emergency alert this summer, according to the Texas Reliability Entity.

During a May 20 "Talk with Texas RE," Evan Shuvo, a senior engineer with the organization, said a spike in energy storage resources has substantially lowered the risk level during the early evening hours as solar energy tails off.

"Storing power in these energy storage resources for when demand is high and there is not enough solar generation available will help the reliable operation of our grid," he said. "There's a low risk of energy shortage during early evening hours compared to last summer."

ERCOT has added 7.4 GW of ESRs since summer 2024, Shuvo said. That's more than half of the 13 GW in increased storage capacity since last summer across NERC's ERO footprint. Overall, ERCOT has boosted its expected capacity by more than 15 GW.

"We have plenty of reserves under the expected peak conditions," Shuvo said.

According to the data shared by Texas RE, ERCOT is projecting a 0.7% increase this summer in net internal demand of 81.9 GW, with 3.3 GW in demand response deducted. With the additional resources since 2024, the grid operator will enter the summer months with a prospective reserve margin of 43.9%.

ERCOT's monthly outlooks for resource adequacy (MORA) for *June* and *July* predict it will have a little more than 91 GW each month to meet demand as high as 79.6 GW during the hour of highest risk for reserve shortages (the hour ending at 5 p.m.).

The ISO will release its August MORA on June 6. August tends to be the hottest month in Texas; ERCOT's record peak of 85.5 GW was set during that month in 2023.

ERCOT has yet to publish its *summer outlook* — Shuvo said it will be released the last week of May — but the National Weather Service said in April it's expecting summer 2025 to be among the hottest on record in Texas. The past three summers ranked among the top six hottest summers since 1895. The grid operator set a record for May when average demand peaked at 77.8 GW on May 14.

Shuvo said the Lone Star State's drought conditions will continue with the precipitation outlook "leaning on the dry side of normal."

"Conditions like this can contribute to high temperatures," he said. "This has a very direct impact on the reliability of generation and transmission system elements. Extreme heat can contribute to elevated load levels for prolonged periods and this can lead to reduced transmission line ratings and major derates of thermal resources." ■

Spearmint Energy's 150-MW battery energy storage facility in West Texas is among the resources expected to help ERCOT meet demand this summer. | *Spearmint Energy*

Regulators Focus on Energy Affordability at NECPUC Symposium

By Jon Lamson

MYSTIC, Conn. — Government officials and industry executives discussed how to mitigate rising energy costs in New England at the 77th annual New England Conference of Public Utility Commissioners Symposium May 19 and 20.

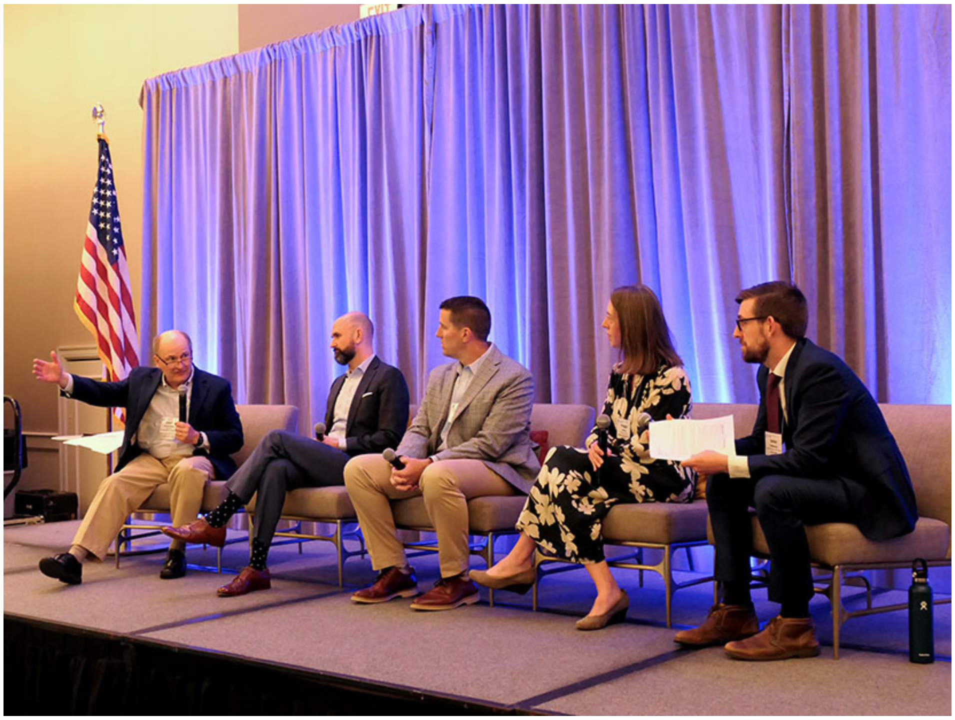
Moderating a panel on affordability, Ron Gerwatowski, chair of the Rhode Island Public Utilities Commission, compared the different components of a customer's bill to a large stack of pancakes. While no one pancake is overwhelming on its own, "when viewed as a tower of components, then you see the problem," he said.

"With the possible exception of the supply costs … I don't think it's fair to blame any one component for the high bills," he added.

While all speakers emphasized the importance of affordability, there were few easy answers and limited consensus about how to meaningfully cut costs on bills. (See related story, *ISO-NE Open to Asset Condition Review Role amid Rising Costs*.)

Dan Dolan, president of the New England Power Generators Association, said energy prices have trended down over the past 10 years when adjusting for inflation, and added that "we are in a time of some of the lowest capacity prices in the history of New England."

Dolan acknowledged that New England faces "massive volatility in cold winters" but argued that "as I look at the data, I don't know where else to really squeeze on the supply end without pushing out resources that are really performing."



From left: Rhode Island PUC Chair Ronald Gerwatowski; Jamie Dickerson, Acadia Center; NEPGA President Dan Dolan; Doug Horton, Eversource Energy; and Maggie Molina, Northeast Energy Efficiency Partnerships | © RTO Insider

Why This Matters

Hard questions about balancing decarbonization and affordability will likely define the region's energy policy landscape in the coming years as lawmakers debate the pace and scale of the transition to clean energy.

Looking forward, with above-market-rate clean energy contracts set to take effect and load growth likely to accelerate in the coming years, "the bottom line is that rates are probably going to go up," Dolan said.

Doug Horton, vice president of distribution rates at Eversource Energy, said "affordability for our customers means looking at the entire stack," while noting that the company's distribution charges are "generally aligned with other utilities across the country providing similar services."

Meanwhile, representatives of climate and energy efficiency organizations also made the case that their portions of the stack were not the drivers of the region's high energy costs.

"I don't see a correlation between recent bill increases and the macro-trends we're seeing on energy efficiency," said Maggie Molina, executive director of Northeast Energy Efficiency Partnerships. Molina said energy efficiency typically provides a roughly 2-to-1 return on investments and warned policymakers that rolling back energy efficiency programs would bring long-term affordability consequences.

Jamie Dickerson, senior director of clean energy and climate programs at the Acadia Center, said it was "a cold, tough winter, there's no doubt about it," but added that "the primary driver of costs was gas and oil, not renewable energy."

He said adding more clean energy to the grid will help diversify the supply mix and drive down market volatility. The New England Clean Energy Connect transmission line, which is slated to come online at the end of this year, should save ratepayers millions annually, while the winter-peaking power production profile of offshore wind should provide significant relief for winter price spikes, Dickerson said.

He resisted the idea that adding new pipeline capacity to the region would lower consumer costs, telling attendees that "we actually don't see that there is an economic case for the buildout of pipelines into New England."

Arguments for new pipelines to New England have seen some revived interest under the administration of President Donald Trump, who was elected with strong financial backing from the fossil fuel industry, which spent more than $219 million during the 2024 election cycle, according to *Yale Climate Connections*.

"We need more pipelines," said Cynthia Niemeyer-Tieskoetter, natural gas markets policy adviser for the American Petroleum Institute. She added that "the system is already facing constraints" during extreme winter weather, with electricity demand projected to increase in the coming decades.

Niemeyer-Tieskoetter lauded the White House for its "pro-energy agenda" and called for permitting reform to reduce the challenges of building new energy infrastructure.


Connecticut Gov. Ned Lamont | © *RTO Insider*

Earlier in the week, New York Gov. Kathy Hochul (D) appeared to agree to concessions relating to a potential new gas pipeline to the Northeast in exchange for the Trump administration lifting the stop-work order on Empire Wind. (See related story, *BOEM Lifts Stop-work Order on Empire Wind*.) Connecticut Gov. Ned Lamont (D) has also signaled that he is open to a new pipeline project.

While increased gas capacity in New England would ease some of the region's pipeline constraints during cold periods — when heating demand backed by firm contracts limits gas generators' ability to access fuel — it is unclear who would pay for this new capacity, or whether it would be a cost-effective solution in the long term.

Gas generators generally do not receive enough incentives to contract for firm fuel, and it is not clear whether gas distribution companies in New England would be willing to take on the costs of new pipeline infrastructure. In 2016, the Massachusetts Supreme Judicial Court ruled that the state's electric ratepayers could not be charged with the costs of new gas infrastructure, a major blow to a proposed $3.2 billion pipeline project by Enbridge, which was ultimately canceled in 2017.

Massachusetts Gov. Maura Healey (D) served as the state attorney general at the time of the SJC ruling and was a vocal critic of the plan to fund pipelines through electric rates. (See *Massachusetts Regulators Endorse Pipeline Contracts*.) Elected governor in 2022, Healey's administration has taken significant steps to transition Massachusetts away from natural gas reliance as the state works to meet its statutory emissions limits.

Doubling down on natural gas likely would undermine state decarbonization efforts, as methane is an intense short-lived greenhouse gas and could risk creating expensive stranded assets as states electrify and transition to renewable power.

Matt Nelson, principal at Apex Analytics and former chair of the Massachusetts Department of Public Utilities, said it is "critical" to coordinate clean energy policy to avoid unnecessary gas investments as states transition to clean energy.

"You could see bills going up in the near term to help avoid these long-term costs, and you have to be good about messaging that," Nelson said, adding that, in the long term, "you're going to have to build clean generation to meet electrifying customers."

"In the short term, you may see some increased emissions as people transition from gas to electric heating," Nelson said. "If you're committed to adding clean resources, however, those emissions will come down over time."

Lamont briefly spoke at the symposium prior to its conclusion, pitching lawmakers on the importance of regional collaboration to help support new and existing generation in the region. He highlighted the Millstone Nuclear Power Plant, which is owned by Dominion Energy and is *under contract* with Connecticut's electric distribution companies through 2029.

"I like Millstone. … It represents about half of our power and almost all of our carbon-free power," Lamont said. "I think we ought to give Dominion the incentives they need to continue, and I can do that a lot more effectively with the other governors."

Lamont advocated for a formal collaboration between Northeast energy officials to ensure resource adequacy in the coming years. He noted that the Northeastern governors will meet in the coming weeks and said this concept is at the "top of the agenda." ■

ISO-NE Open to Asset Condition Review Role amid Rising Costs

By Jon Lamson

With projects to replace deteriorating transmission infrastructure adding billions of dollars to New England electric bills, ISO-NE has announced it's open to taking on a limited "asset condition reviewer" role, intended to help increase oversight on the projects.

"Given the significant benefits to the region from a robust process and independent review of asset condition projects (ACPs), we are now exploring the issue further," ISO-NE wrote in a *memo* May 15.

While the scope of the role has yet to be determined, the RTO has insisted it could take on only a strictly advisory role and would not review the prudence of investments or assume any legal liability. The regional transmission owners would retain the right to decide whether to move forward with individual projects.

The rising costs associated with ACPs have drawn increased scrutiny over the past two years. There are about $6 billion in asset condition projects listed as proposed, planned or under construction in ISO-NE's ACP *project list*, while more than $5 billion in asset condition projects have come online since the start of 2015.

According to a *2024 report* by the Rocky Mountain Institute (RMI), asset condition spending in New England "increased eightfold from 2016 to 2023" and now makes up a majority of pooled transmission system spending in the region.

The high costs are not limited to New England; RMI's report noted that the portion of residential electric bills spent on transmission and distribution increased from 10% in 2005 to 24% in 2020. The bulk of this added spending has gone to local projects, as the U.S. has built far fewer new high voltage transmission lines in the early 2020s compared to the prior decade.

Why This Matters

As energy costs rise in New England, state officials and consumer advocates argue that reigning in excess asset condition spending is essential for electricity affordability in the region.

From left: Chair Phil Bartlett, Maine Public Utilities Commission; Claire Wayner, Rocky Mountain Institute; Commissioner Kerrick Johnson, Vermont Department of Public Service; Alan Trotta, Avangrid; Anne George, ISO-NE | © *RTO Insider*

Along with rising costs, New England officials have expressed concern about a lack of transparency and regulatory oversight on the projects, with some arguing transmission owners have abused the process to increase spending.

"These asset condition projects frequently do not receive oversight from state regulatory authorities, as rebuilding aging assets is often exempt from state regulatory processes," said Claire Wayner of RMI, one of the authors of the asset condition report, speaking at the annual symposium for the New England Conference of Public Utility Commissioners (NECPUC) on May 20.

While the projects are subject to a prudence review at FERC, the formula rate process provides "very few opportunities for oversight of these projects," Wayner added.

Some asset condition projects have drawn specific concern from state officials, including a $385 million line rebuilding project proposed by Eversource Energy in New Hampshire. (See *New England States Raise Alarm on Eversource Asset Condition Project*.)

Recently, a couple of projects presented at the NEPOOL Reliability Committee highlight potential discrepancies in how transmission owners approach asset condition projects. Vermont Electric Power Co. (VELCO), a transmission company collectively owned by the states' distribution utilities and structured to return profits back to customers, *proposed* to replace 41 wooden structures on a 115-kV line, with a projected cost of $5.8 million.

At the same meeting, Eversource, an investor-owned utility company, presented an *update* on a project to replace 41 wooden structures on a couple of sections of 115-kV line in Connecticut. The project's estimated cost is over $16 million, more than double the cost of VELCO's similar project.

While Eversource serves roughly half

the load in the region, it's responsible for 79% of all spending in New England on ACPs that have come online since 2015, according to ISO-NE data. The company has stressed its investments are critical to preserving the reliability of its aging grid.

"Inconsistent decision and design standards across transmission owners that lead to notable cost disparities between the same or very similar asset condition projects is just bad behavior," said Commissioner Kerrick Johnson of the Vermont Department of Public Service (DPS). Prior to taking his position as a DPS commissioner, Johnson held several senior roles at VELCO.

"Bad behavior by any New England [transmission owner] impacts every customer in each of the six New England states," Johnson said, adding that this "undermines trust in the entire regional collaborative transmission enterprise and punishes those least able to pay."

Johnson added that he recently reviewed six ACPs flagged as the most "needlessly expensive" by the New England States Committee on Electricity (NESCOE), finding that the "cost delta between that which would have been expected for these projects and that which was submitted for each of these projects … totals nearly half a billion dollars."

He said he based his review on VELCO cost analyses and accounted for the varying costs typically seen in different states and utility service areas.

ISO-NE previously expressed reluctance about taking on an asset condition oversight role, arguing it is not a regulatory entity. However, following discussions with the states and transmission owners, ISO-NE said it is comfortable taking on a limited reviewer role.

Anne George, chief external affairs and communications officer at ISO-NE, said the RTO's board met the prior week and offered support for continued discussions "about ISO-NE having an asset condition review role."

George stressed the importance of limiting the role to a non-regulatory, advisory function, but said it could "provide additional information and address some of those concerns about information asymmetry, and then people could take that information to FERC or take it to another forum and make the case."

NESCOE and the Massachusetts Attorney General's Office, along with transmission owners Avangrid and National Grid, offered public support for the concept following the announcement.

"NESCOE expects that the asset condition reviewer will provide states and stakeholders with an independent, objective review of asset condition proposals, including needs, solutions and cost drivers," NESCOE *wrote*. "ISO-NE's asset condition reviewer should provide information necessary to enhance confidence in the proposed investments, or in the alternative, information that others would be able to rely on in challenging a project."

NESCOE added there remains a "core need" to better incorporate asset condition needs into the regional planning process, which could enable those projects to be appropriately sized in anticipation of the need for more transmission capacity. ISO-NE has estimated new transmission to meet load growth through 2050 could cost up to $26 billion. (See *ISO-NE Prices Transmission Upgrades Needed by 2050: up to $26B* and *ISO-NE Analysis Shows Benefits of Shifting OSW Interconnection Points*.)

In March, NESCOE asked FERC to direct the creation of an independent transmission monitor (ITM) with a broader scope, intended to "support the efficacy and efficiency of transmission planning and cost transparency." Some stakeholders also have supported the concept of a monitor with authority to review the prudency of transmission projects.

ISO-NE has expressed concern about having a separate independent entity overseeing the RTO's planning processes and has resisted taking on anything more than an advisory role.

At the NECPUC symposium, some stakeholders expressed interest in state or federal regulatory changes to go along with a new asset condition reviewer role for ISO-NE.

"There's definitely additional work that FERC could do to improve its formula rate-making process," said Wayner of RMI. Wayner said this could include "looking at the automatic presumption of prudence that transmission projects get through formula rates and maybe reconsidering that for some of these projects if they are not being adequately reviewed at the state level."

Johnson of the Vermont DPS expressed his hope "the states pass individual review of asset condition projects like we have in Vermont."

In Massachusetts, Gov. Maura Healey (D) recently introduced a bill that would allow the state's Energy Facilities Siting Board to review "any proposed reconductoring, replacement or rebuilding of a transmission facility or group of transmission facilities on an existing transmission corridor that has an estimated cost of at least $25 million." (See *Mass. Gov. Healey Introduces Energy Affordability Bill*.)

As state officials consider other changes to the asset condition process, ISO-NE has said it's considering adding the evaluation and creation of an asset condition review role to its 2026 work plan.

"Following the ISO's assessment and the development of any preliminary framework, we plan to bring that proposal to our stakeholder community for discussion and feedback," it added.

For ACPs proposed in the interim period before a reviewer role can be established, Johnson asked representatives of the transmission companies at the NECPUC symposium to commit to answering all outstanding stakeholder questions before proceeding with a project. Representatives of each company signaled their agreement to the commitment. ■

MISO Requires Load Shed in New Orleans to Avoid Grid Instability

By Amanda Durish Cook

MISO initiated an hourslong load shedding event in greater New Orleans over Memorial Day weekend with nuclear power outages appearing to play a role.

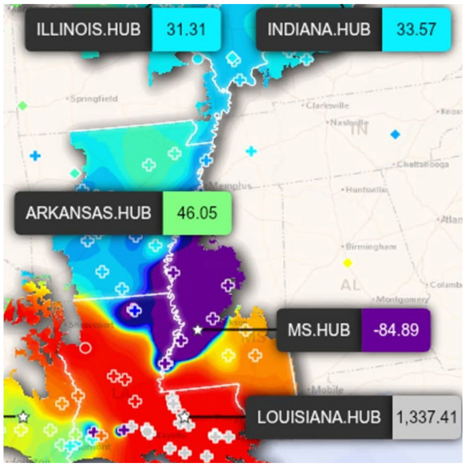
The RTO said on *X* that it ordered Entergy and Cleco to drop about 600 MW on the evening of May 25 to "maintain the reliability of the bulk electric system."

"High temperatures in Louisiana led to higher-than-expected demand, and with planned and unplanned transmission and generation outages, MISO needed to take this action as a very last resort. MISO is coordinating closely with Entergy and Cleco to restore power as quickly as possible," MISO wrote at the time.

Entergy New Orleans and Entergy Louisiana reported they initiated the rolling blackouts on MISO's orders around 5 p.m. CT. Entergy said the "last resort" actions were to "prevent a more extensive, prolonged power outage that could severely affect the reliability of the power grid."

"MISO is directing actions to be taken to restore the system to normal operations as quickly as possible and will direct Entergy to stop these outages as soon as the power shortfall no longer threatens the integrity of the rest of the electrical power system," Entergy said in a *press release* at the time. Later that day, the utility issued a second release announcing MISO canceled further period load shed. Entergy said it would work with MISO to understand the sudden load shed directive.

Local news outlets reported that more than 100,000 customers around New Orleans were impacted by the controlled outages. Entergy said it restored power around 8 p.m. CT. Entergy and Cleco's territories in Orleans, Jefferson, St. Tammany, St. Bernard and Plaquemines parishes reportedly were affected.



MISO pricing the evening of May 25 | *MISO*

Cleco also *confirmed* it instituted rolling outages on MISO's instructions.

"If the power supply cannot meet the demand, periodic power outages could be needed to protect the stability of the power grid and prevent widespread lengthy outages," said Jennifer Cahill, director of corporate communications. "This was the case yesterday when we took the unprecedented step, as directed by MISO, to force outages to some customers in St. Tammany Parish."

RTO Insider has reached out to MISO for further comment. MISO's real-time market *notifications* don't list any emergency steps that might have preceded the event.

River Bend Station | *Entergy*

Why This Matters

Diagnosing exactly what happened in Louisiana, and why, surely will be debated in MISO in the coming weeks and months, along with how to prevent it from happening again.

The outage could be the result of hot weather and nuclear power unexpectedly going offline.

Louisiana Public Service Commissioner Davante Lewis said Entergy's 974-MW River Bend Nuclear Station in St. Francisville, La., tripped offline May 25 as Entergy attempted to restore it to service. The unexpected outage reportedly occurred at the same time Entergy's Waterford nuclear plant in Killona, La., was on a scheduled outage. The Nuclear Regulatory Commission *listed* both reactors as offline before the holiday weekend.

Meanwhile, temperatures around New Orleans registered at about 90 degrees Fahrenheit.

Lewis told local station *WWL-TV* that the simultaneous scheduled and unscheduled outages should not have risen to a load shedding event. "That means there's more to the story — either bad forecasting, bad modeling or higher demand than was projected," he said.

Fellow Commissioner Eric Skrmetta said the load-shed orders arrived less than three minutes before action was required so utilities didn't have the option to cut interruptible industrial customers first in an attempt to reduce demand. He said the notification time was "unacceptable" and said upcoming commission meetings would focus on appropriate notification times from RTOs before delivering load shed instructions.

Until now, MISO had directed load shedding just once in the past 17 years, ordering about 700 MW offline in MISO South during Winter Storm Uri in early 2021. ■

MISO Stakeholders Request Theoretical 2025/26 Auction Clearing Sans Sloped Curve

By Amanda Durish Cook

Stakeholders continue to ask MISO to crunch hypothetical auction clearing prices absent the RTO's new sloped demand curve that sent prices past $660/MW-day for summer.

During a May 21 Resource Adequacy Subcommittee meeting, multiple stakeholders asked MISO staff to publish 2025/26 hypothetical auction clearing prices through a simulation with the old, vertical curve. The exchange led Independent Market Monitor David Patton to chime in to defend MISO's installment of a sloped demand curve.

The 2025/26 planning year auction marked the first time MISO used a sloped demand curve, meant to procure more capacity than strictly necessary to meet MISO's one-day-in-10-years reliability standard. MISO ultimately cleared 137.5 GW, more than the 135.3 GW it designated prior to the auction to meet its one-day-in-10-years reliability standard, at a cost of $666.50/MW-day for the upcoming summer. (See *MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction*.)

"Given that we just switched from a vertical demand curve to a sloped demand curve," it's appropriate for MISO to show what the clearing would have been with a vertical curve, WEC Energy Group's Chris Plante said during the meeting.

WPPI Energy's Steve Leovy said he failed to see how MISO could claim that its sloped demand curve "enabled MISO to secure more capacity at a significantly lower price," as the RTO claimed in its presentation. He asked which alternate reality MISO used as a comparison.

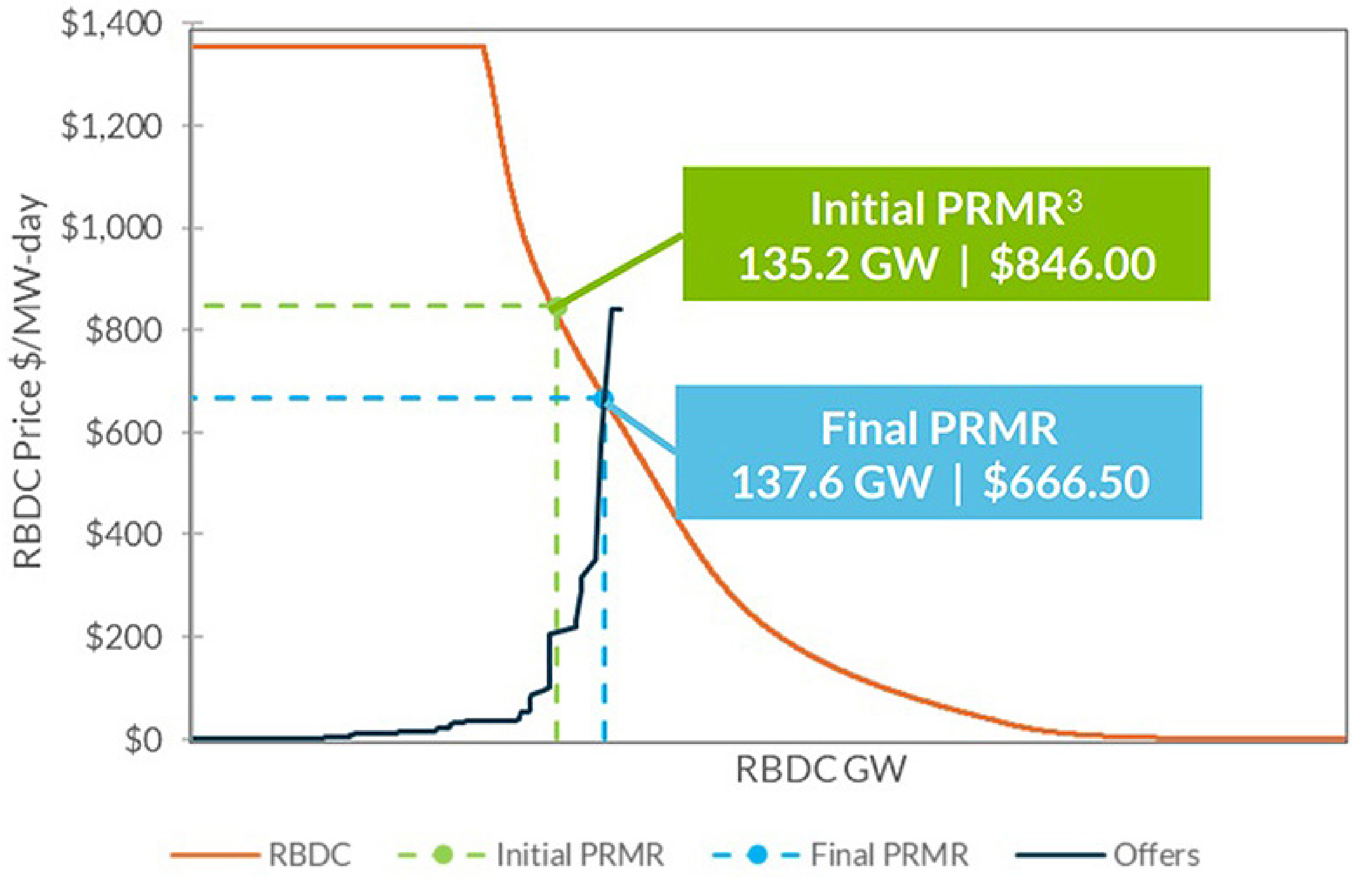
MISO Resource Adequacy Manager

Why This Matters

MISO's stakeholders — still sorting through summer's expensive capacity auction clearing prices — want to compare price points based on a scenario where MISO never adopted a sloped demand curve.

Andy Taylor said MISO's comparison "is not a counterfactual to" the old, vertical demand curve, but a counterfactual to other sloped demand curve designs.

MISO develops its sloped curves by assessing the value of additional capacity beyond the one-day-in-10-years stan-



The price MISO's original planning reserve margin would have cleared at versus the final amount MISO's sloped demand curve judged necessary for the 2025/26 capacity auction | *MISO* dard relative to its price. If the cost isn't too steep, MISO shapes the slopes with the OK to clear extra megawatts.

MISO said had the auction cleared only to its initial planning reserve margin requirement of 135.2 GW, prices would have been $846/MW-day based on the sloped curve it ultimately used.

Plante said MISO's comparison is "very confusing to a casual observer."

Clean Grid Alliance's David Sapper said he didn't believe MISO's auction clearing process as described in its business practice manual makes sense. He asked MISO to redraft a process that could be more readily understood.

Sapper said he also was "dismayed" that FERC Chair Mark Christie, whom he said is consequential in RTOs' capacity auction changes and "a scholar and a gentleman," didn't seem to understand auction clearing processes.

"He seems to have thrown up his hands that they're impenetrable," Sapper said.

Minnesota Power's Tom Butz said prices this year "rocketed up to CONE-like values" and it seems they will be there for the foreseeable future.

But IMM David Patton said, "for the first time," auction clearing prices in MISO reflected the marginal value of capacity. Patton said the auction clearing an additional 2% in capacity is a good thing despite what stakeholders might think.

"I know this is a shock with prices being high, but we do find that this is going to set up for a much more reliable system," he said. Patton said prices should compel utilities and regulators to make more informed decisions in integrated resource plans and selecting resource retirement dates.

Patton estimated summer prices would have been about $20/MW-day under the old, vertical curve. But he cautioned that hypothetical, low prices aren't as attractive as they appear.

"What you should take away from that is: Our previous market was flawed and wouldn't have produced prices in line with reliability," Patton said.

Had inexpensive capacity prices held court for another planning year, Patton said it wouldn't meet any "fundamental objectives of the capacity market to set prices this way."

During the April 29 auction results call, Taylor said had MISO used its vertical curve, the auction would have produced "extreme, very low or very high" pricing outcomes as it has in years past.

At the time, Clean Grid Alliance's David Sapper asked if MISO would commit to re-running the auction if it's discovered the RTO drew on incorrect inputs in its sloped curve. MISO counsel Michael Kessler said it would be "highly unusual" for FERC to order any capacity auction to be rerun.

The 2025 auction results are poles apart from auction results a decade ago, when Southern Illinois' Zone 4 clearing price of $150/MW-day sparked concerns that pivotal supplier Dynegy manipulated capacity availability to raise prices. (See *FERC Sets Dynegy's MISO Market Manipulation Case for Hearing*.)

MISO to Allow Resources with Provisional Agreements to Provide Capacity

At the same resource adequacy meeting, MISO said it will take steps to allow resources with provisional generator interconnection agreements (GIAs) to offer capacity in MISO's seasonal capacity auctions if they can deliver.

MISO's tariff expressly prohibits resources with provisional GIAs from participating in capacity auctions. MISO announced it will pursue a turnaround on its longstanding policy and open the auction to the resources with the provisional agreements starting with the 2026 seasonal capacity auction.

"We would like these resources to participate in the planning resource auction as well, provided they've procured deliverability," Taylor said.

Taylor said the "current length and state" of MISO's interconnection queue might have influenced MISO's rethinking of the nearly complete resources' ability to furnish capacity. ■

Amid Fraud, MISO Plans Stricter Testing of Demand Response

By Amanda Durish Cook

MISO said starting with the 2026/27 planning year, it will require its demand response resources to demonstrate actual demand reductions through tests to weed out imposters in the capacity market.


Joshua Schabla, MISO | © RTO Insider

"We need to see everyone perform a real power test," Joshua Schabla said during a May 21 Resource Adequacy Subcommittee meeting.

MISO said requiring real power tests with actual load cuts decreases the likelihood that resources fraudulently register in capacity auctions. MISO currently allows its demand response fleet to submit mock tests or opt out of testing. Under the new regime, real power tests would be required annually for at least one hour. Exceptions would be limited to trusted performers with a history of responsiveness and overrides because of state regulations.

Schabla said the last time load-modifying resources were deployed was Dec. 22, 2023, long enough to need renewed proof that the resources can discount load levels.

MISO said it would file the changes with FERC at the end of May for a June 1 go-live date. The grid operator said the "rapid" deadline would ensure all demand resources have the summer to perform a test in preparation for the 2026/27 planning year.

MISO would permit waivers of testing requirements only in two limited circumstances: when a test is precluded by regulatory restrictions, or when a resource requesting a waiver hasn't amassed any penalties in the past three planning years, hasn't changed its registered value in the past three years and — also in the last three years— has made at least an 80% reduction of the maximum accredited value it has requested for the upcoming planning year.

Schabla said testing waivers should be reserved for resources that have shown to be "solid" through scheduling instructions or MISO-initiated tests.

MISO also plans to stop letting aggregated demand response drop to a firm service level for testing. The RTO's pending demand response accreditation *filing* before FERC similarly cuts the firm service level-reduction option for aggregations. Schabla said "gaming opportunities are substantial" when aggregated resources can specify a firm service level baseline.

MISO recognizes two types of demand response: those that make megawatt reductions and those that drop to a predetermined firm service level.

The stricter testing is part of MISO's larger reining in of demand response following a handful of FERC investigations and findings that companies have manipulated the capacity market. MISO in March proposed an overhaul of its capacity accreditation methods for demand response that would be based on whether they can help during system risk. (See *Stakeholders Ask FERC to Soften MISO's Proposed DR Accreditation*.)

A few months before its April capacity auction, MISO said it would hold its demand response to heightened testing requirements. (See *Following DR Exploitation, MISO Announces Stiffer Requirements Before Capacity Auction*.) The new tariff filing would solidify the change going forward.

MISO's Independent Market Monitor recently predicted more enforcement actions from FERC on the horizon for bad actors among MISO's demand response fleet. During the Organization of MISO States' Resource Adequacy Summit in May, Patton said a planned data center has been collecting demand response payments even though its construction location remains an empty field. (See "IMM: Problem Remains with 'Not Real' DR," *MISO CEO: Slim Reserves Not Necessarily Bad*.)

Schabla read from lines from recent FERC orders levying penalties on companies that have offered phantom demand response to prove the point that MISO needs stricter testing requirements.

Why This Matters

Demand response resources preparing to enter MISO's 2026/27 capacity auction will have to pass testing to be included in the RTO's DR fleet. MISO is betting stepped-up testing and other crackdowns on demand response will solve its fraud problem.

"I hope you can agree with us that we need to put in controls today" that demand response resources can prove they can reduce demand, Schabla said. He said it's "clear we need to act, and we need to act fast."

MISO said the "lack of a real power test was specifically cited in several recent FERC orders and stipulations as helping to perpetuate the fraud."

For the 2025/26 planning year beginning June 1, MISO said it cleared about 3.7 GW of demand resources that waived the requirement to perform a real power test.

Under the upcoming summer clearing price of $666.50/MW-day, the grid operator said a 10-MW demand resource can expect to be compensated $613,180 over the season.

MISO said, in total, auction revenue this year for demand response resources that have waived a real power test is about $282 million.

"There's a great deal of money to be made in our capacity market," Schabla said. He added that it's appropriate for demand resources to flock to MISO's market to offer their capabilities but, "if we're going to pay that much money, it has to be real."

Schabla said MISO is looking for "reasonable requirements, reasonable barriers" when attracting demand response, although he admitted nothing would be a "panacea" that would completely defeat fraud. ■

MISO Gen Developers Sour on RTO's JTIQ Cost Allocation

Clean Grid Alliance, Developers Object to Inclusion of 2023 Queue Cycle in Cost Sharing

By Amanda Durish Cook

Why This Matters

A push from MISO to include cost sharing on Joint Targeted Interconnection Queue lines for its 2023 cycle of interconnection requests has set off deeper concerns among generation developers regarding MISO and SPP's JTIQ cost allocation.

MISO generation developers have pushed back on MISO's cost allocation of the $1.65 billion Joint Targeted Interconnection Queue (JTIQ) portfolio in partnership with SPP, reportedly saying MISO's late-stage alterations have eroded the value of the seams planning.

The discord became apparent after a MISO announcement in April that it now plans to incorporate JTIQ lines and assign new generation upgrade costs from them beginning with the 2023 cycle of interconnection queue entrants. The RTO must seek FERC permission to begin including JTIQ lines beginning with the 2023 interconnection cycle because it would use the modeled lines in an earlier queue cycle than it first anticipated.

MISO confirmed in mid-May that it will file with FERC soon to allow the earlier incorporation of JTIQ into its queue studies. (See *MISO Readies JTIQ Filings, Hints at More Tx Portfolios with SPP*.)

Ordinarily, MISO locks in modeling assumptions when it kicks off studies shortly after it accepts the new cycle of generation projects. However, MISO's 2023 class of interconnection customers have been in a holding pattern while MISO attempts to get a handle on its oversaturated queue. The RTO has said models as they existed two years ago are too stale to be relied upon as it begins processing proposals again. MISO said it would work from its latest transmission modeling when studies kick off. (See *MISO: New Software Effective, Faster than Previous Queue Study Process*.)

Some generation developers in MISO reportedly are unhappy with JTIQ being accounted for in the 2023 queue cycle. That stems from concern that cost assignments on the lines could climb as high as under MISO and SPP's erstwhile affected system study process.

MISO *said* its view is queue cycles that have not yet started down the study process "must be able to take advantage of all approved transmission and reduce uncertainty for the next cycles."

MISO and SPP are assessing JTIQ costs 100% to interconnection customers; costs will be assessed a per-megawatt JTIQ charge that is billed directly by either MISO or SPP.

Beyond that, MISO in 2024 added a second step to its JTIQ cost assignments in the form of what it calls the Expanded Scope Study. The additional study is meant to pinpoint line upgrades beyond JTIQ projects that interconnecting generation might require.

Clean Grid Alliance (CGA), speaking on behalf of some of the developers it represents, said it regards the Expanded Scope Study as the old affected system study that produced unexpectedly high upgrade costs and was meant to be replaced by the JTIQ process. In an interview with *RTO Insider*, CGA representative Rhonda Peters said though the name is different, the function is the same.

MISO has said while the JTIQ study is designed to address congestion for about 28.6 GW of generation projects wishing to connect near the seams, the Expanded Scope Study is designed to address lingering issues around the point of interconnection.

CGA told MISO it is "strongly against" merging JTIQ projects in the 2023 interconnection cycle. The alliance asked MISO to begin work on changing its tariff and joint operating agreement with SPP to make cost assignments more certain and contained for MISO generation developers. The alliance made a similar request when MISO was designing its JTIQ cost allocation in 2023 and 2024. It said its request was ignored repeatedly.

CGA said as it stands now, interconnection customers beginning with the 2023 cycle could be in "for high cost variability when projects are subjected to JTIQ." It said the penalty-free withdrawal option in MISO's queue likely won't be enough to counter the costs because it doesn't expect the Expanded Scope Study or the JTIQ cost estimates to be completed at that point in the process.

MISO has said the point of JTIQ allocation is to know up front what portion of costs that generation will be on the hook for. The RTO has said the alternative to including JTIQ in the 2023 queue cycle is MISO and SPP conducting another affected system study, where costs wouldn't be fleshed out until the second or third phases of the queue. MISO also pointed out that its interconnection procedure is "not a risk-free process."

MISO expects costs from the separate, Expanded Scope Study would be known later, once in the first phase of the queue and again in the second phase of the queue. MISO and SPP will treat a few buses into one another's footprint as their own system for the purpose of determining whether a generation developer should pay for upgrades under the Expanded Scope Study.

Differing DFAX Thresholds

Generation developers in MISO also oppose MISO employing a lower distribution factor (DFAX) threshold than SPP uses for its internal projects in allocation. When singling out necessary upgrades on generation projects requesting unguaranteed energy resource interconnection service, MISO holds its developers to a more rigid 10% DFAX impact threshold than SPP's 20%. For projects requesting the higher-quality network resource interconnection service, MISO and SPP both use a 5% DFAX impact threshold.

MISO halved its 20% DFAX value in 2023 despite opposition from stakeholders who claimed MISO did not complete an engineering analysis to support the change. They also argued that such a major change belonged in a tariff filing to FERC, not in a business practice manual edit. Their complaint over MISO's change is pending before FERC. (See *Renewable Developers Challenge MISO's Lower Congestion Limit*.)

In comments to MISO, CGA said MISO's lower DFAX means that MISO developers will have more exposure to SPP network upgrade costs than SPP developers. The alliance also said that unsuspecting "projects far away from the seams that would have never needed JTIQ lines" nevertheless could get pulled into JTIQ cost sharing "simply because of power flows in the path of least resistance." CGA said the second study step once again means developers at the seams will have no solid cost predictions on the network upgrades their projects might induce.

CGA also told MISO that the JTIQ 345-kV portfolio lines not having a cost cap mechanism is problematic, given the

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100% cost assignment to developers. CGA said that cost overruns on transmission construction would add to generation developers' tabs. Peters said MISO using its usual network upgrade allocation of 90% to interconnection customers and 10% to load on 345-kV and above projects would have afforded some budget oversight because states likely would question mounting costs even on their 10% portion.

Peters also said the 5% power flow DFAX threshold seems arbitrary and insignificant, and that MISO would be better served if it split costs among generators that actually cause or worsen constraints. CGA said JTIQ essentially reversed a long-standing FERC precedent: the "but for" principle that assigns costs to cost-causers. The alliance said that under JTIQ, many interconnection customers would be assigned costs for JTIQ lines even though they do not depend on the lines and have not contributed to any constraints if the lines were not in the model.

'Affected System Study on Steroids'

MISO developers opposing MISO's allocation methods declined to be interviewed for this article and instead opted to effectively speak through Clean Grid Alliance's comments.

Peters confirmed that many generation developers oppose MISO's JTIQ cost allocation mechanisms and called them poorly understood among stakeholders.

Peters said cost recovery of the transmission lines is uncapped for generation developers and that their costs can increase over the 10-plus years the lines are built.

"There is no regulation or oversight on cost increases on those lines," Peters said. She said the current two-phase JTIQ allocation could saddle developers with more costs than MISO and SPP's past affected system study process. She said that's why MISO's JTIQ cost allocation was so strongly opposed by MISO interconnection customers at FERC. She also pointed out that CGA and other renewable trade associations are appealing the JTIQ cost allocation at the 7th U.S. Circuit Court of Appeals.

Peters said generation developers made sure to enter the 2023 cycle to avoid potentially "disastrous" outcomes funding the JTIQ projects.

"These projects spent a lot of money to enter when they did," Peters said. "[And] MISO customers are going to have to build out SPP's system to a 10% DFAX." She added that the uneven threshold between MISO and SPP is likely to "significantly cost shift from SPP to MISO generators near the seams."

"We call it affected system study on steroids," Peters said, adding that she thought the JTIQ began as a good idea, but generation developers got "trampled" in the stakeholder process, including cost allocation discussions. She said there are "fatal flaws" in several aspects of the allocation methodology that make costs to generators highly unpredictable.

Peters said developers made "commercial decisions to enter the queue" based on the absence of JTIQ cost sharing in the 2023 cycle.

"This introduces significant uncertainty and cost increases to projects which undermines the predictability necessary for project financing and development. [Definitive Planning Phase] 2023 projects entered the queue having specifically modeled the transmission system without the unpredictable cost exposure JTIQ creates, and do not want the process changed at this point," CGA said in its comments to MISO.

Shell's Savion, a solar and energy storage developer, agreed that developers entered the queue in 2023 strategically before JTIQ integration began. In comments to MISO, Savion said MISO's move to group the 2023 entrants into the cost allocation now is "akin to retroactive ratemaking."

MISO: Allocation Already Has FERC Support

MISO, on the other hand, stressed that FERC unanimously *approved* the JTIQ cost allocation, including the Expanded Scope Study, in late 2024.

"The JTIQ portfolio was developed in close collaboration with SPP and our joint stakeholders to support generation at our seam and strengthen regional reliability. MISO and SPP followed a transparent, stakeholder-driven process to develop the JTIQ study framework and cost allocation methodology," MISO spokesperson Brandon Morris wrote in an emailed statement to *RTO Insider*. ■

NYISO Seeking Info on Dispatchable Generation not in Queue

By Vincent Gabrielle

NYISO on May 21 asked developers to tell the ISO about any dispatchable generation projects that have not yet been submitted to the interconnection queue by June 13.

Ross Altman, senior manager of reliability planning for NYISO, told the Transmission Planning Advisory Subcommittee that any responses would support the ISO's Comprehensive Reliability Plan.

"We are very concerned about the shrinking margins," Altman said. "Just knowing that there's anything else out there that's early in the pipeline that could potentially be in service by the time we run into narrowing margins could be helpful for us in coming up with the Comprehensive Reliability Plan."

Altman said any projects submitted in response would be nonbinding and the ISO would respect all confidentiality requests from stakeholders. He said any information obtained through this request would be used "on an aggregated basis" and that the ISO would not identify any specific developers or locations.

NYISO sent its request out to all stakeholders earlier in the week. The ISO is requesting the following information from developers:

- nameplate capacity (MW), or if a storage resource, energy capacity (MWh);
- fuel type and technology;
- location;
- anticipated project schedule and commercial operation date;
- ownership or development partners; and
- status of site control.

Independent Power Producers of New York spokesperson Jordan Lomaestro told *RTO Insider* that IPPNY's membership was still "digesting" the request and deciding whether to submit anything to NYISO.

Why This Matters

The request is unusual, showing how concerned NYISO is with shrinking reserve margins.

Lomaestro said IPPNY favored an all-of-the-above approach to new resources on the grid and noted its *comments* submitted to the Public Service Commission in support of any and all new technologies to support the state's climate goals.

Alliance for Clean Energy New York spokesperson Barry Wygel said the group did not have an official position on the request but noted that it "isn't typical for NYISO."

"There's some interest in seeing how the submitted information will be aggregated and what insights NYISO will share," Wygel told *RTO Insider*. ■

Ravenswood Generating Station in Queens, N.Y. | © *RTO Insider*

BOEM Lifts Stop-work Order on Empire Wind

Officials Signal that Rejected Gas Pipeline in N.Y. Could Move Forward

By James Downing

The Empire Wind project off the coast of New York is back from near death after the U.S. Bureau of Ocean Energy Management lifted a stop-work order and its developer Equinor announced it would move forward.

"We appreciate the fact that construction can now resume on Empire Wind, a project which underscores our commitment to deliver energy while supporting local economies and creating jobs," Equinor CEO Anders Opedal said in a statement May 19. "I would like to thank President Trump for finding a solution that saves thousands of American jobs and provides for continued investments in energy infrastructure in the U.S. I am grateful to Gov. [Kathy] Hochul for her constructive collaboration with the Trump administration, without which we would not have been able to advance this project and secure energy for 500,000 homes in New York."

The stop-work order was issued on April 16 and was criticized by New York officials and renewable energy advocates. The 810-MW project is planned for just off the coast of New York City and would connect to the grid at a site in Brooklyn. (See *Feds Move to Halt Construction of Empire Wind 1*.)

Hochul welcomed the change in course from the Department of the Interior,

Why This Matters

Empire Wind would provide New York City with 810 MW of additional supply as soon as 2027, while the deal on pipelines could alleviate high winter electricity prices in the Northeast, though the Trump administration and the region's states will need to do more than revive the Constitution Pipeline to accomplish that.

The first monopile for Equinor's Empire Wind 1 project off the coast of New York | *Sif Group*

saying in a *statement* she had spent weeks working with the federal government to ensure the project could move forward.

"Equinor will resume the construction of this fully permitted project that had already received the necessary federal approvals," Hochul said. "I also reaffirmed that New York will work with the administration and private entities on new energy projects that meet the legal requirements under New York law. In order to ensure reliability and affordability for consumers, we will be working in earnest to deliver on these objectives."

Interior Secretary Doug Burgum *posted* he was pleased with Hochul's comments.

"I am encouraged by Gov. Hochul's comments about her willingness to move forward on critical pipeline capacity," Burgum posted on X. "Americans who live in New York and New England would see significant economic benefits and lower utility costs from increased access to reliable, affordable, clean natural gas."

Burgum is correct directionally, but the project at issue, the Constitution Pipeline, would increase supply for some natural gas customers, while the pricing problem in the Northeast comes in winter at peak electricity demand, when generators cannot access the gas they can at other times of the year.

Trump has spoken publicly in favor of reviving the project, and the executive order setting up the National Energy Dominance Council, which Burgum chairs, calls for approving pipelines into New England.

FERC approved the Constitution Pipeline more than 10 years ago, but it did not get a permit from the New York State Department of Environmental Conservation. Developers effectively asked FERC to overrule the state, but in 2018 the commission *denied* the request, with three Trump nominees all voting for the order.

In a talk hours before BOEM reversed course that was largely focused on how Trump's election was leading to more capital flowing to fossil fuels, 1PointSix CEO Terrence Keeley criticized the decision to stop work on the project at a conference held by RealClearEnergy and the U.S. Chamber of Commerce. Halting work on a permitted project funded by Norway's state oil company that was about a year from delivering electricity to the grid "seemed punitive," he said.

"You can say goodbye to foreign direct investments in the United States for any type of project, renewable or unrenewable, when that type of unreliability becomes commonplace," Keely said.

American Clean Power Association CEO Jason Grumet made a similar point in a statement calling the decision to move forward with Empire Wind good for reliability.

"Fully permitted projects must have policy consistency and certainty to deliver the infrastructure required to meet America's growing electricity demand," Grumet said. "Our nation needs all types of energy infrastructure to lower energy prices and support economic growth. In lifting the stop-work order, the administration has honored a principle that is essential to all infrastructure investment."

At a Federal-State Current Issues Collaborative meeting on gas-electric coordination in April, ISO-NE CEO Gordon van Welie testified that the region has been dealing with constrained gas at peak demand for decades, and it leads to very high prices as reliability is dependent on attracting LNG cargoes when demand is also in Europe and Asia. (See *FERC-NARUC Collaborative Examines Ongoing Issues with Gas-electric Coordination*.)

A decade ago, FERC found a creative attempt by the New England states to require electric utilities to pay for extra pipeline capacity outside of its authority. Since then, states have focused on imports from Canada and offshore wind development to hedge against price volatility in the winter, van Welie said.

"Recently, the issue of affordability has been given more emphasis, and the idea of possibly investing in additional gas infrastructure has resurfaced," van Welie said. "However, it isn't clear if there is an available counterparty in New England to commit to the long-term contracts that will be required. So, in summary, any viable solution to the gas constraint issues must involve, and requires the support of, state officials."

The move to increase pipeline capacity in the Northeast is opposed by environmental groups, with Food and Water Watch noting in a statement that Hochul has already approved major fossil fuel expansions in recent months, including new compressors for the Iroquois pipeline.

"If Gov. Hochul moves to revive the Constitution Pipeline — or any other fracked gas pipeline project — it would be a reckless and unacceptable capitulation to President Trump and the polluting fossil fuel interests backing him," said Laura Shindell, the group's New York state director. "This pipeline was defeated already because the overwhelming majority of New Yorkers refused to be collateral damage for the gas industry. Turning her back on communities to appease polluters would be an astonishing failure of leadership. If Hochul decides to go down this foolish path, she will be met at every turn by the full force of New York's energized climate movement. She will certainly regret it." ■

Calpine Proposes Time-varying TCCs at NYISO

ISO Asks for Stakeholder Feedback on 2026 Project Priorities

By Vincent Gabrielle

Calpine has proposed that NYISO split its 24-hour-only transmission congestion contracts into *on-peak and off-peak products*, arguing it would reduce the cost of congestion hedging by better aligning it with load and generation behavior.

"We are asking for this to help us manage our risk [and] the renewables sector — solar and wind generators — to manage their risk," Jung Suh, manager of ISO analytics for Calpine, said at the Budget Priorities Working Group meeting May 19. "All of the benefits from this will benefit the consumer, the ratepayer and the end user."

TCCs allow generators to hedge the congestion component of their output. Suh said this was especially important for intermittent resources because of their varying load profiles. Wind and solar power do not and cannot operate at maximum capacity with perfect predictability, which makes more precise hedging preferable, Suh explained.

Currently, NYISO is the only grid operator not to offer time-granulated *financial transmission rights*. Suh argued that offering such rights could increase TCC auction revenue, increase market transparency and decrease the cost of hedging congestion. He said this would allow load-serving entities to fit the demand profile of their customers better.

Howard Fromer of Bayonne Energy Center asked whether stakeholders had heard this presentation before. Suh said that he had given the exact same presentation five years ago.

"You were five years younger and five years better looking back then when I presented it," Suh said. "It received the No. 1 ranking in the [project prioritization] survey five years ago."

Why This Matters

NYISO is the only grid operator not to offer time-granulated financial transmission rights.

"So it never got picked up by the ISO, is what you're saying," Fromer said. "It was ranked, and ranked high, and it wasn't pursued?"

Another stakeholder chimed in that the ISO worked on it for a year before shelving the proposal.

Several stakeholders voiced support for the proposal. One said it would help them hedge flows between ISOs and help their renewables portfolio. Others said they strongly supported the proposal and hoped it got in the 2026 project prioritization list.

Project Prioritization: 2026

NYISO has identified *44* market projects for next year. Of those, five are *mandatory projects*, five are continuing projects for next year, and 22 are on the "prioritize" list for next year.

The ISO will share its scoring of the projects on June 24 and send stakeholders their own survey to complete June 30. The stakeholder survey results should be in at the end of July, and a preliminary budget should be released by mid-August.

"I think it would be useful … that when we list project prioritizations, the market participants understand which ones you are recommending," said Doreen Saia, of Greenberg Traurig. "That could affect the list we see as part of project prioritization. Folks need to understand if they are waiving their choices."

Fromer asked about the Market Purchase Transaction Hub project, which is listed for deployment in 2026. He said that seemed strange, given that all of the work was done and all that was left was to turn it on.

Kevin Pytel, director of product and project management for NYISO, said the market design was finished but the software still needed to be completed in order to get it to deployment, so it's back on the table for the prioritization process.

Kevin Lang, speaking on behalf of New York City, expressed confusion, asking why the project would have to be reconsidered after being prioritized multiple times and with the design complete.

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Pytel said implementation costs might change opinions as to what projects needed to be prioritized year to year. He showed a slide where the definitions of project milestones were listed. "Market Design Complete" is considered fairly mature but not quite ready to have software developed to implement it, for example.

"Anything under the blue line that reaches that milestone in 2025 is automatically considered a continuing project for 2026," Pytel said. "Functional Requirements is the first milestone; if you achieve that this year, you will be automatically considered continuing for next year."

Pytel said stakeholder feedback should be sent to his *email* by May 31 to be incorporated into the next prioritization presentation. May 30 is the deadline for stakeholders to identify new projects and have them included in the scoring survey. ■

NYISO Outlines Storage as Transmission Proposal

Update on Winter Capacity Market Project

By Vincent Gabrielle

NYISO on May 20 presented an outline of how it plans to implement *storage-as-transmission assets* (SATAs), drawing critiques from stakeholders representing end-use customers and generators.

The ISO has been working storage as transmission since 2023. It would allow energy storage systems to act as regulated transmission, making them eligible for cost-of-service rate recovery and to be considered as solutions for transmission needs in the ISO's planning processes. This would mean that SATAs would not be dispatched via the wholesale market beyond what would be necessary for them to remain ready to withdraw or inject into the grid.

Katherine Zoellmer, a market design specialist for NYISO, explained to the Installed Capacity Working Group that SATAs would only be considered as transmission solutions for needs arising from N-1-1 contingency events. The ISO would dispatch all SATAs for direct charging and discharging manually. Zoellmer said NYISO wants to limit SATAs to 20 MW per substation and to 200 MW across the New York grid. The ISO wants these rules in place to reduce the impact of SATAs on the wholesale market, she said.

That prompted questions from stakeholders. Kevin Lang, representing New York City, said it seemed strange to focus on market impacts when anything, including adding generation, has a market impact.

"I understand your concern about the impacts on the market, but are you looking at the benefits of storage as transmission? That it could be a lower-cost option for consumers?" Lang asked. "It just seems like you're focused on one small piece."

Zoellmer responded that the ISO was committed to evaluating SATA "consistent with other transmission solutions."

Other stakeholders said the N-1-1 contingency was restrictive in terms of which problems SATAs could solve. Another stakeholder said it seemed like restricting SATAs from market-based compensation might discourage investment by developers in other market-based storage in the same area.

When the discussion turned to megawatt limits, Lang voiced his disappointment.

"These are ridiculously low numbers for a storage resource that could take the place of a multibillion-dollar transmission line," Lang said. "It's really troubling here that your focus is, again, not on the benefits, but how we need to avoid impact."

Multiple Intervenors — an association of large industrial, commercial and institutional energy consumers — asked whether the ISO could share the reasoning behind its approach. Zoellmer said the ISO would "take that back" for consideration.

In a post-meeting interview, Zoellmer clarified that the megawatt limits on SATAs were intended to make it easier for operators to manage their dispatch. When asked if there was a software solution to dispatch, Zoellmer explained that programming software to restrict SATA resources so they aren't being dispatched constantly was a challenge, which is why manual operation was only being considered for now.

| NextEra Energy

Why This Matters

NYISO's proposal is still in the very early stages, but it's already receiving stakeholder scrutiny.

Winter Reliability Capacity Enhancements

Michael Swider, senior market and technologies strategist for NYISO, presented questions the ISO was considering as it moved forward with the Winter Reliability Capacity Enhancements project, its effort to make the capacity market reflect the shift of New York's peak demand from summer to winter.

NYISO is evaluating whether the methods for determining the seasonal ICAP demand curves and reference points for capacity prices are working. Beginning with the 2025/26 capability year, the ISO is using reference points adjusted by the relative risk in each season.

Swider cited the "winter-to-summer ratio," defined as the average amount of available capacity in winter relative to summer over a historical three-year period. As the resource mix changes, the ratio may no longer represent which resources are available. The ISO and the New York State Reliability Council have brought this up in other contexts, specifically *the winter gas constraints white paper*. (See *Winter Fuel Constraints Concerning for NYISO*.)

Swider also discussed adjusting the "zero crossing point" of the demand curve to retain price stability and a *stakeholder proposal* to amplify price signals in the capacity market during peak months. ■

PJM MRC Briefs

Stakeholders Endorse Proposal to Add Transparency to ELCC

VALLEY FORGE, Pa. — The PJM Markets and Reliability Committee *endorsed* by acclamation a proposal intended to add transparency to the RTO's effective load-carrying capability (ELCC) process and how the ratings it produces contribute to resources' capacity accreditation. (See "PJM Presents Proposal to Add Transparency to ELCC," *PJM MRC/MC Briefs: April 23, 2025*.)


PJM's Lisa Morelli presents to the Markets and Reliability Committee. | © *RTO Insider*

Providing more information to generation owners about the amount of capacity their units can provide is one of several areas where stakeholders have sought to make changes through the ELCC Senior Task Force. The MRC endorsed a proposal in March to add two resource categories and limit the Capacity Performance deficiency penalty rate for units whose accreditation falls between a Base Residual Auction and Incremental Auction. (See *PJM Stakeholders Endorse Proposals to Rework ELCC Accreditation*.)

The transparency proposal would create an exception to PJM's confidentiality requirements to allow market sellers to request data showing the historic performance of the resource through June 2012, even if that extends prior to the owner's acquisition of the asset. Proponents argued those data are integral to understanding how PJM determines the inputs driving the unit's ELCC rating.

Before rounds of ELCC analysis are initiated, pre-study stakeholder sessions would be held to review the assumptions and updates to data inputs PJM is considering. Additional sessions would be held once the analysis is complete to discuss the results. PJM would also publish an annual report outlining the assumptions, methodology and results of the ELCC analysis, including any sensitivities.

Additional sensitivities could be conducted after the analysis, such as developments in the load forecast, weather data or resource performance.

Independent Market Monitor Joe Bowring asked PJM to produce a legal opinion outlining its perspective that it can share confidential information from a prior resource owner to a new owner without permission from the former. PJM legal staff said their client is the RTO, not the Monitor, after which a member also requested additional information on PJM's legal reasoning.

Discussion of CETL Deferred

The MRC voted to delay consideration of an *issue charge* focused on a "disconnect" between PJM's winter-skewed risk modeling and the use of summer peaks to calculate capacity emergency transfer limits for locational deliverability areas. (See "LS Power Seeks Issue Charge to Align CETL Calculation with Winter Risk," *PJM PC/TEAC Briefs: Oct. 8, 2024*.)

LS Power Director of Project Development Tom Hoatson, who made the motion to defer, said he believes the issue is intertwined with the concept of a seasonal capacity market and suggested that the two should be discussed together. He also said that the stakeholders and PJM engineers who would lead the work are the same personnel engaged with discussions on other areas of the ELCC paradigm, presenting workload challenges.

Greg Poulos, executive director of the Consumer Advocates of the PJM States (CAPS), said the issue charge, which was sponsored by LS Power, was well developed and broached an issue of importance to consumer advocates. He said they could support a delay of a few months, but not longer.

The motion to defer until "stakeholders undertake work on a seasonal capacity construct" was endorsed with the support of all sectors except end-use customers.

Stakeholders Torn on Further SATA Education

Stakeholders held mixed perspectives on whether to recommence work on an *issue charge* seeking to establish rules for storage acting as a transmission asset (SATA), with some feeling that more education is warranted and others arguing that it is time to move on to proposal development.

PJM Director of Stakeholder Affairs Dave Anders said that, after a series of presentations at the Operating Committee in recent months, he believes the education component of the work has run its course and said the issue charge is slated for an endorsement vote at the MRC's June 18 meeting. He added that approving the issue charge does not mean that further education and stakeholder discussion cannot happen.

The committee voted in October 2024 to delay acting on the issue charge until PJM had completed education sessions at the OC, both to allow stakeholders to focus on several capacity market proposals being considered at the time and to bring them up to speed on a SATA *proposal* last considered in 2021. The OC's sessions focused on the 2021 proposal, how SATA could impact *operations* and FERC's *regulatory authority*. The issue of developing rules for SATA was brought by PJM in September 2024, nearly four years after members voted to delay further activities on the subject until market rules for storage had been established. (See "Vote on Issue Charge to Establish SATA Rules Deferred," *PJM MRC Briefs: Oct. 30, 2024*.)

Constellation Energy's Juliet Anderson said there are still unanswered questions around where SATA would fall into the federal and state jurisdictions over transmission and distribution networks. She noted that the October 2024 deferral delayed action on the issue charge until education at the OC had been completed.

Bowring asked whether PJM believes it's appropriate to proceed without a more complete understanding of how SATA could impact market operations. Anders responded that market impacts fall under the issue charge's key work activity 6.

Poulos said most issue charges have a significant educational component, so it's surprising to him that there is opposition to continuing that work here. He said SATA is a priority for advocates who see it as a valuable tool for resolving reliability issues, and they are frustrated that barriers are being put up to having the subject discussed further.

Exelon Director of RTO Relations and Strategy Alex Stern said there have been several discussions over the past five years to determine whether storage can act as transmission. In that time FERC has issued policy statements, and other RTOs have developed their own rules, while PJM has been artificially blocked from advancing the discussion by stakeholders using pre-education as a pretext for delay, he said. Whether or not stakeholders want to proceed with establishing a SATA framework, he said, their position should be made clear and communicated to the states, which have been pushing for increased storage deployment.

"I'd just as soon like to know whether this is something we can have in the toolkit or not," he said.

PPL's Robin Lafayette said SATA has been discussed at more than 30 meetings and is clearly a tool PJM believes it needs to have available.

"Other ISOs and RTOs have found ways forward on this issue, and I do acknowledge some of the issues raised by some of my colleagues on interactions with the markets," he said. "PPL strongly supports trying to find a way forward on this issue; even if it is a targeted, limited tool, it could be a valuable one."

1st Read on Uplift Formula Proposal

PJM Senior Director of Market Settlements Lisa Morelli *presented* a first read on a proposal to rework how balancing operating reserve (BOR) credits are calculated, including a new metric to determine whether a resource is following dispatch signals. (See "Stakeholders Narrowly Endorse Uplift Changes," *PJM MIC Briefs: April 2, 2025*.)

The proposal would replace the three desired megawatt metrics used to determine deviation charges with a new tracking ramp-limited desired (TRLD) metric, which would compare actual output to how a resource should be operating if it had followed dispatch instructions. Morelli said the existing metrics are limited to how dispatch instructions and resource output change over five-minute intervals, which can mask when a resource is deviating from instructions by small amounts over a long period, particularly because there is a 10% margin before a resource is found to be deviating.

The BOR credit formula would also be revised to take the lesser of real-time output or the TRLD, adjusted for a unit's ramping parameters. The period for which a resource is eligible for uplift would also be realigned to when its commitment began and continue through either the minimum run time parameter or the end of the commitment.

Depending on how a unit operates, the proposal could either lead to increased uplift payments or higher deviation charges, Morelli said, adding that PJM and the Monitor, which jointly sponsored the proposal at the Market Implementation Committee, aimed to take a fair and balanced approach to how uplift would be affected by the proposal, rather than just reducing the amount of uplift paid.

If endorsed, a soft launch would be rolled out at the end of this year or early 2026, starting with calculating how the TRLD would affect settlements and communicating that to market sellers through their Market Settlements Reporting System reports. Changes to actual settlements would not come for another year once the full implementation begins.

Gregory Pakela, manager of regulatory affairs for DTE Energy Trading, said the proposal could have significant impacts during periods of high system stress and asked if PJM could conduct backcasts on how it would have changed settlements during the two winter storms in early 2025, when conservative operations were initiated.

Morelli said PJM has conducted limited backcasting, but there's a balance between the number of staff hours that fully recalculating results would take versus the benefits. She said PJM is comfortable that the proposal is worth moving forward with.

Vistra's Erik Heinle said the phased implementation process allows market participants to have more understanding of how their resources would fare under the proposed paradigm. Having the opportunity to spend a year understanding how TRLD would determine when a unit is following dispatch and the ability to update the unit's parameters based on that information is crucial, he said. ■

— Devin Leith-Yessian

SPP Readies Participants for Next Phase of Markets+

By Tom Kleckner

With FERC having fully blessed the Markets+ tariff, SPP has begun the day-ahead market's transition to Phase 2 with the first of two webinars designed to educate potential participants on what lies ahead.

"We're really moving forward into … actually building out Markets+ and the systems, processes and procedures necessary to implement the tariff," said Jim Gonzalez during the May 21 *webinar*. (A second webinar is scheduled for June 30.)

"We're ramping up that pre-planning work in order to hit the ground running full steam ahead when Phase 2 starts in earnest," Gonzalez added. SPP's senior director of seams and Western services since May 1, he said staff is gathering a list of potential market participants to understand who will participate in building system requirements and developing a readiness program to help work through the implementation effort.

The RTO expects 13 entities initially to help fund Phase 2, most notably the Bonneville Power Administration, the Pacific Northwest's 800-pound gorilla. (See *BPA Chooses Markets+ over EDAM*.)

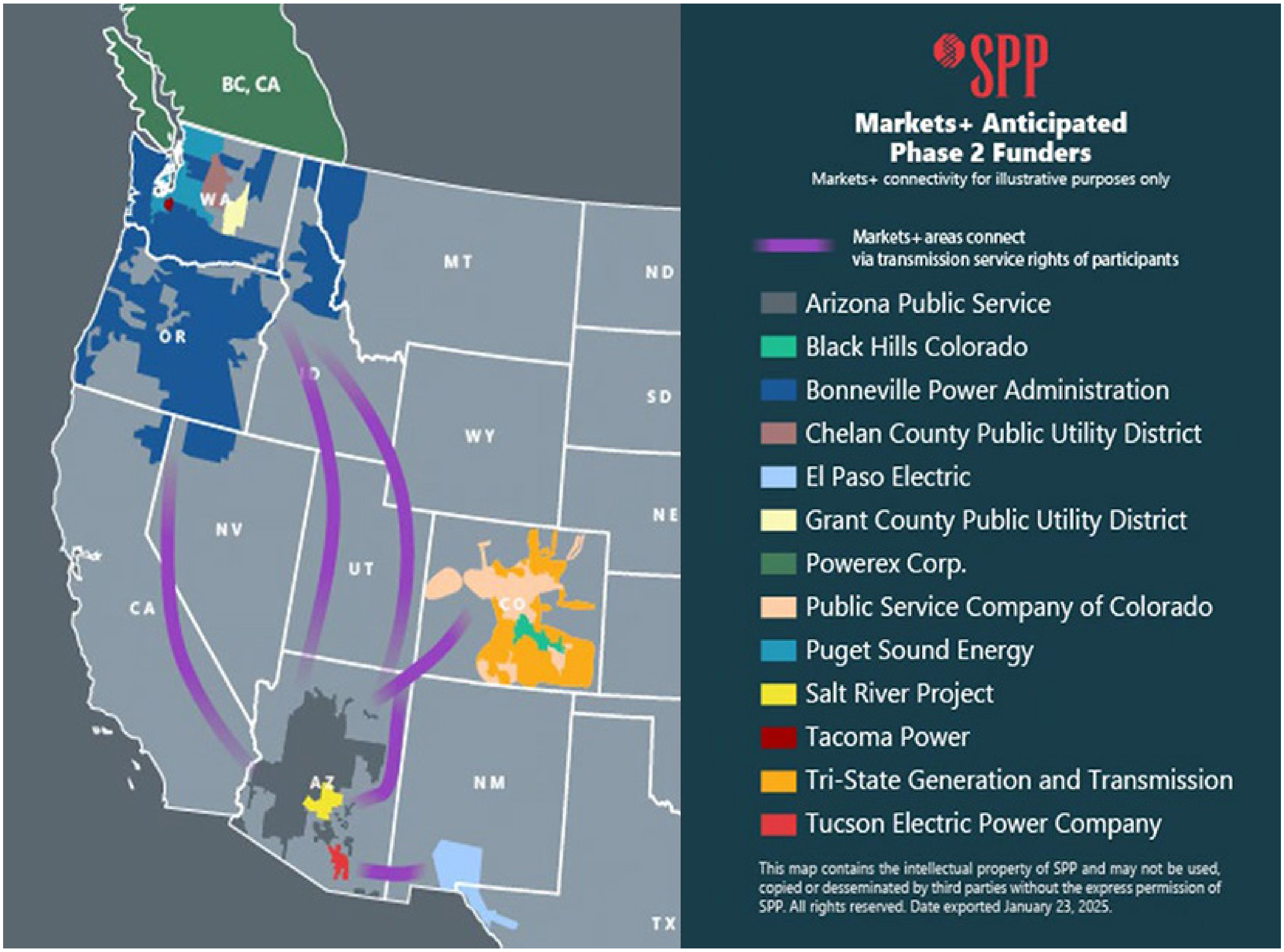
Those entities and other interested stakeholders must sign and submit one of three agreements through SPP's *Request Management System* to continue engaging and voting as rostered members in the various Markets+ stakeholder groups:

- Funding agreements, for balancing authorities and their embedded entities.

What's Next

SPP has set a soft deadline of July 23 for submitting agreements and retaining seats on stakeholder groups. The rosters will be posted for the stakeholder-led Markets+ Participant Executive Committee's approval and then confirmed by the MPEC during its Aug. 12-13 meeting.

Under that agreement, they will provide collateral in the form of a letter of credit or cash that allows SPP to use debt to build the systems.



The current funding participants for Markets+'s next phase | *SPP*

- Stakeholder agreements, for non-governmental organizations and others that don't expect to be active market participants.
- Participation agreements, for entities in a BA without a funding agreement and that register the utility's load.

The stakeholder and participation agreements both come with $5,000 one-time fees, similar to SPP's RTO participation model. The grid operator will waive the fee for nonprofit NGOs that can prove their status.

SPP has set a soft deadline of July 23 for submitting the agreements and retaining seats on stakeholder groups. The Markets+ stakeholder groups must submit their roster nominations on that date. The rosters will be posted for the stakeholder-led Markets+ Participant Executive Committee's approval and then confirmed by the MPEC during its Aug. 12-13 meeting in Portland, Ore.

The Interim Markets+ Independent Panel, composed of three SPP board members that are overseeing the market's development, then will confirm the chairs.

"If you intend to participate with Phase 2 governance, we will need an executed agreement in any one of these three [categories]," SPP's Kelli Schermerhorn said.

She warned attendees that participants who don't sign one of the agreements will lose their seat on working groups or task forces.

"Those Phase 1 agreements are going to cease to be effective," Schermerhorn said. "Independent governance is a cornerstone of all SPP offerings. Our Markets+ design has been largely accomplished by these task forces and working groups."

Three other decision dates have been set as deadlines for balancing authorities, transmission providers or market participants if they want to be part of the initial market launch: Sept. 1 (BAs), Oct. 1 (transmission providers) and Dec. 1 (MPs).

FERC in April approved the Markets+ $150 million funding agreement and its recovery mechanism. The commission also granted SPP's request to issue debt securities to cover the agreement and fund the market's implementation over three years until its scheduled Oct. 1, 2027, go-live date. (See *SPP MPEC Members Celebrate Markets+ Funding Order*.)

The funding agreement requires the entities to provide the collateral backstop to SPP's lender in supporting the RTO's financing. The collateral is equal to the amount of the entities' Phase 2 obligations.

SPP says the cost to repay the financing will be incorporated into Markets+ rates and will relieve participants from the burden of providing "large sums of money to directly fund Phase 2." SPP is splitting the phase into two stages, with participants required at first to provide collateral equal to two-thirds of their Phase 2 obligation. The first stage expires six months after the initial funding threshold has been met, at which point participants must provide collateral equal to their full Phase 2 obligation.

Funding participants withdrawing from the agreement must pay their Phase 2 obligation to SPP, protecting the remaining participants from the withdrawal. ■

Company Briefs

Cannon Leaves NV Energy for AEP Transmission

Doug Cannon, the CEO of NV Energy for the last six years, will leave the post to join American Electric Power Transmission in mid-June.

Brandon Barkhuff, general counsel and chief compliance officer for NV Energy, will replace Cannon.

Cannon's departure comes amid a call from Nevada Public Utilities Commission staff for an investigation into allegations that NV Energy overcharged 80,000 customers by at least $17 million, then failed to fully refund them.

More: *Nevada Current*; *AEP*

Amazon Suspends Plans for Minnesota Data Center

Amazon last week said it had suspended plans for a data center in Becker, Minn., after state lawmakers and Gov. Tim Walz said they will reduce tax breaks for these projects.

The company said it moved ahead with the project based on how quickly it thought it could obtain permits and utility agreements, but it believes those timelines are now "more uncertain."

State leaders recently said they agreed to eliminate a sales tax exemption on electricity for data centers. Together the exemptions have been worth about $100 million a year for data center companies.

More: *The Minnesota Star Tribune*

Honda to Scale Back on EVs, Focus on Hybrids

Honda Motor last week said it was scaling back its investment in electric vehicles given slowing demand and would be switching its focus to hybrids.

The company also dropped its target for EV sales to account for 30% of its sales by the 2030 financial year. Honda also slashed its planned investment in electrification and software by that year by 30% to $48.4 billion.

The automaker is aiming to sell 2.2 million to 2.3 million hybrid vehicles by 2030, a huge jump from 868,000 sold last year. That also compares with a total of 3.8 million vehicles sold overall last year.

More: *Reuters*

Meta, AES Sign Solar PPAs in Kansas, Texas

AES last week announced it has entered into two long-term power purchase agreements with Meta.

The PPAs are for 650 MW to support Meta's data centers in Texas and Kansas.

More: *AES*

Federal Briefs

Geothermal in Great Basin Could Produce 10% of U.S. Power

Geothermal energy in the Great Basin of Nevada and adjoining states could produce electricity equivalent to 10% of the current U.S. power supply, according to the U.S. Geological Survey.

The projected 135 GW would be a major increase, considering geothermal energy currently contributes less than 1% to the nation's power supply, the agency said.

The next region to be evaluated will be the Williston Basin in North Dakota.

More: *Reuters*

BLM Seeks Input on Proposed Dodge Flat II Solar Project

The Bureau of Land Management last week announced it is seeking public comment on the proposed Dodge Flat II solar project in Washoe County, Nev.

If approved, Dodge Flat Energy Center could construct, operate, maintain and eventually decommission and reclaim an approximately 200-MW solar facility with a battery energy storage system, an on-site substation and a one-mile 345-kV transmission line to the Olinghouse substation.

The comment period closes on June 20.

More: *BLM.gov*

Northeast news from our other channels

N.Y. Finalizes REC Contracts for 2.57 GW of Renewables

NetZero Insider

West news from our other channels

U.S. Senate Approves Resolution to End California's EV Mandate

NetZero Insider

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

State Briefs

ARIZONA

State Adopts New Fire Mitigation, Utility Liability Law

Gov. Katie Hobbs on May 12 signed a new law focused on utility wildfire mitigation and liability exposure.

Under the law, investor-owned utilities and public power providers must submit wildfire mitigation plans every two years to the Department of Forestry and Fire Management for approval. These plans must identify fire-prone areas, outline risk-reducing protocols and include power shutoff protocols for extreme fire conditions to stop wildfires before they start. The law also establishes legal protections for utilities and cooperatives that follow their approved mitigation plans.

More: *The Gila Herald*

ARKANSAS

Carroll County Bans Wind Farms for 5 Years

The Carroll County Quorum Court last week passed a five-year moratorium banning any new commercial wind or solar energy facilities in the county.

The ordinance exempts Scout Clean Energy, which began construction in November at its Nimbus Wind Project, but prevents it from expanding beyond its 30-turbine plans.

The ordinance will be in effect until five years after the last of Nimbus' turbines begins producing electricity, or until the court decides to lift the moratorium.

More: *Arkansas Democrat Gazette*

COLORADO

PUC Approves Xcel's Peak-use Rates

The Public Utilities Commission approved new Xcel Energy rates for residential customers, which will allow the utility to charge more for power during weekday evening hours.

The new pricing means residential customers will pay the most for power during "on-peak" hours of 5 p.m. to 9 p.m. on non-holiday weekdays. Currently, the peak rates stretch from 3 p.m. to 7 p.m. on those days.

More: *CPR News*

GEORGIA

Georgia Power, PSC Agree to Rate Freeze

Georgia Power announced it will not seek to raise base rates for the next three years under a proposed agreement with the Public Service Commission's Advocacy Staff.

If approved by the PSC, the agreement would cancel the rate case Georgia Power was planning to submit by July 1. However, it doesn't mean there would be no increases, as the utility will soon submit its cost recovery plan from Hurricane Helene. Georgia Power could also ask for increases on bills to cover costs for natural gas, coal and other sources of fuel.

The PSC will hold hearings on the freeze proposal before voting on whether to deny, change or approve it.

More: *The Current*; *Rough Draft Atlanta*; *Georgia Recorder*

IOWA

Gov. Reynolds Appoints Martz as Chair of Utilities Commission

Gov. Kim Reynolds last week appointed Sarah Martz as the new chair of the Utilities Commission, effective immediately.

Martz has served as a commissioner since May 2023.

Reynolds had nominated Erik Helland to another term as chair, but the Senate adjourned without voting on his appointment.

More: *The Gazette*

KENTUCKY

PSC Approves EKPC's Natural Gas Facility in Casey County

The Public Service Commission last week granted a Certificate of Public Convenience and Necessity to East Kentucky Power Cooperative (EKPC) to construct a new natural gas station using Reciprocating Internal Combustion Engines in Casey County.

EKPC proposed to construct a new facility using 12 Wartsila 18V50DF engines. Each engine will produce approximately 18,132 kW of power for a combined production of 214 MW.

More: *Kentucky Today*

LOUISIANA

PSC Rejects Docket Seeking More Power Competition

The Public Service Commission last week voted 4-1 to reject the idea of allowing full or limited "retail access" in the power sector.

The vote allows Entergy to continue as the dominant electric provider for the state's industrial sector.

Lane Sisung, consultant for the PSC, said the docket being debated hinged on whether industrial customers could go around Entergy without costing other customers more money. If the docket had been allowed to go forward, staff would have collected data over the coming months to evaluate whether costs would rise for other customers.

More: *Nola.com*

PSC Officially Terminates Energy Efficiency Program

The Public Service Commission last week officially terminated plans for the state's energy efficiency program.

The PSC voted 3–2 back in April to scrap plans for an independently operated energy efficiency program more than 14 years in the making. That vote reversed decisions made the year prior establishing program standards and hiring an independent administrator.

More: *KADN*; *Floodlight*

NEW JERSEY

Senate Committee Backs Bills Targeting Data Centers

The Senate Environment and Energy Committee last week approved a series of bills meant to reduce the impact of electricity prices.

The bills would raise data centers' share of electricity costs, boost construction of energy storage and create an automatic approval process for residential solar projects, among other things.

More: *New Jersey Monitor*

RHODE ISLAND

House OKs Utilities Buying Out-of-state Nuclear Power

The state House of Representatives last week approved legislation allowing public utilities to purchase nuclear power at a competitive cost from out-of-state facilities.

The bill would permit utilities that provide electric and gas distribution to participate in programs that have the capacity to deliver nuclear power. It would allow the utility to procure nuclear power and enter long-term contracts.

The measure now moves to the Senate.

More: *Warwick Post*

TEXAS

Senate Confirms Gleeson, Hjaltman to PUC

The state Senate last week unanimously confirmed Chairman Thomas Gleeson and Commissioner Courtney Hjaltman to the Public Utilities Commission.

Gleeson has worked on the PUC for 16 years in a variety of roles, while Hjaltman has served since her nomination in June 2024.

More: *Texas.gov*

VIRGINIA

Appalachian Power Requests Rate Increases

Appalachian Power has asked the State Corporation Commission for permission to raise rates to recover costs on renewable energy projects and complying with environmental laws.

Separately, Appalachian is asking for permission to continue evaluating its Joshua Falls property in Campbell County for a potential small modular nuclear reactor. The approval is necessary before Appalachian can ask permission to charge customers for related SMR development costs.

The average residential monthly bill would go up by $6.63 (3.8%) if the commission approves the request. The increase would not occur before March 1, 2026.

More: *Cardinal News*

WISCONSIN

PSC Approves MGE Plans to Build Solar Array

The Public Service Commission approved Madison Gas and Electric (MGE) to build a 20-MW solar array and 40-MW battery storage system in Fitchburg.

The Sunnyside Solar Energy Center is expected to be operational in 2026, while the battery storage is expected to be live in 2027.

More: *DailyEnergyInsider*

PSC OKs We Energies' Plan to Build New Natural Gas Plants

The Public Service Commission last week approved We Energies' plan to spend about $1.5 billion to build two natural gas power plants.

A $1.2 billion natural gas plant in Oak Creek would essentially replace aging coal units at the South Oak Creek power plant, while a $270 million plant in Kenosha County will complement the utility's existing peaker plant in Paris.

We Energies plans to begin construction this year.

More: *Wisconsin Public Radio*