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YES ENERGY

RTO Insider

YOUR EYES AND EARS ON THE ORGANIZED ELECTRIC MARKETS

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FERC/FEDERAL

Trump Replacing FERC Chair Christie with Laura Swett

Vinson & Elkins

FERC Chair Mark Christie's tenure running the agency is coming to an end as President Trump plans to nominate a replacement, Laura Swett of Vinson & Elkins. Swett has previous experience at FERC, serving on the staff of former Chair Kevin McIntyre and former Commissioner Bernard McNamee, both Trump nominees in his first term. She also worked at the Office of Enforcement.

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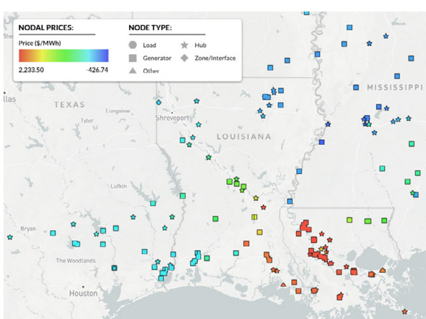
MISO



Yes Energy

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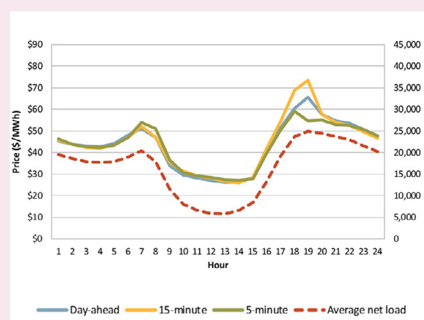

CAISO

The Solar Duck Has Run Amuck, but that May Change Soon (p.3)

New England has the most pronounced situation in terms of behind-the-meter solar resources, but it and California are by no means the only grids that are — or will be — greatly affected. A brief look at the interconnection queues suggests significant levels of solar energy are on tap for various regions.

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

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In this week's issue

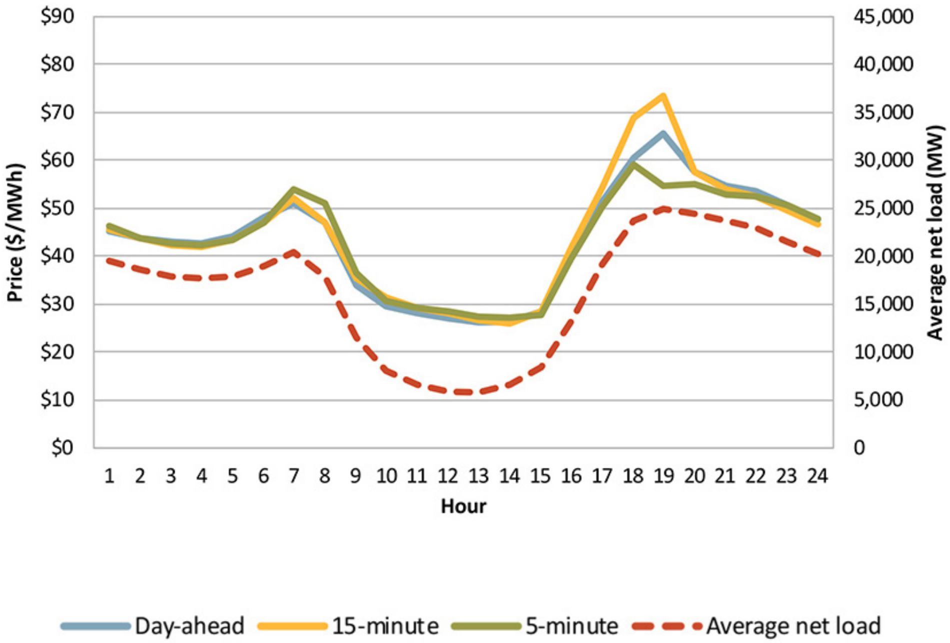
The Solar Duck Has Run Amuck, but that May Change Soon

By Peter Kelly-Detwiler

Peter Kelly-Detwiler

If you follow power markets, then you are familiar with the duck. The *solar "duck curve" received its moniker 13 years ago* in sun-drenched California, with its emerging multitude of rooftop solar arrays and thousands of megawatts of utility-scale arrays. In that market, the electricity demand net of solar — in other words, the load that must be met with imports and dispatchable resources — frequently drops to zero these days.

Solar also has exerted a significant impact on California's electricity market, with prices typically falling significantly by mid-day, and then firming up — often tripling — by early evening, before softening again at night and the wee hours of the morning. The fourth quarter of 2024 was a typical example of this dynamic. For the last three months of the year, *hourly load-weighted day-ahead prices* sat in the high $20/MWh range in the early afternoon, before soaring past $65 around 7 p.m.



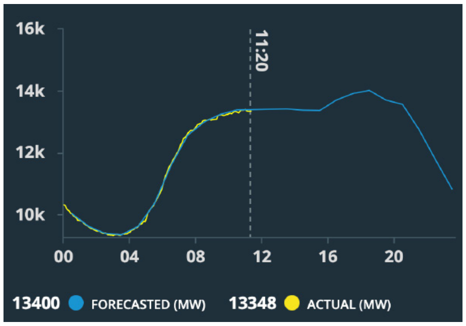
Hourly load-weighted average energy prices for balancing areas in day-ahead market (CAISO October–December) | *CAISO*

A Tale of Two Price Regimes

In California, the duck generally sets the rules, and the other resources — whether imports, batteries or gas generation — respond accordingly. The funny thing about ducks is they have offspring, a fact that is becoming clear in a number of other power markets, with some effects more pronounced than others.

New England, not the sunniest of places, is an instructive example. The first duckling landed there April 21, 2018. On that day, for the first time, net load in the early hours of the morning exceeded mid-day demand. Almost all of the solar creating this change was subsidy-driven rooftop solar. In New England, utility-scale solar typically has lagged behind because there's simply not a lot of unforested open space to build on.

New England's duck found suitable rooftop habitat and subsidy-related forage and began to quickly fatten up its belly. By 2022, *the region saw 45 "duck days,"* with that number vaulting to 73 days the following year and *106 in 2024*.

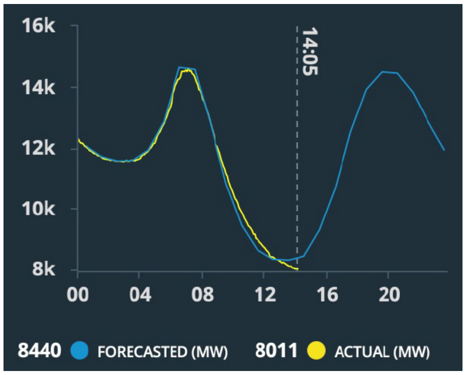


| *ISO-NE*

The duck phenomenon is most prevalent in spring, when demand for air conditioning is relatively low, the position of the sun is optimal and there are fewer leaves to block out potential sunlight. Panels also are relatively cool in the spring and operate at higher efficiency.

Though spring is ideal, duck days now occur in every month of the year, and the sag of the duck's belly grows ever deeper. In fact, Easter 2025 saw *ISO-NE record an all-time low* of just 5,250 MW, 1,000 MW below the 2024 record. That dynamic is likely to continue to strengthen. An April 2025 ISO-NE overview *forecasts the contribution of solar growing significantly* in coming years, from 6,500 MW at the end of 2023 to nearly 13,500 MW by 2033.

With recent tariff increases affecting the cost of imported solar panels, combined with significant looming cuts to federal tax subsidies, these forecasts now appear less likely. However, additional solar capacity still is likely to be installed for some time, even if added somewhat more slowly. Thus, we will see both frequent and precipitous declines in New England electricity demand daily whenever there's sun. Prices also will



| *ISO-NE*

fall increasingly into negative territory at times — that's already happening. Sunny spring days will look like April 9, shown below, but the roller coaster dips and rises will be much steeper unless we add enormous amounts of storage and distributed resources to the mix.

Sunny days likely will see an increasingly bifurcated world of pricing: one pricing regime on sunny days when the solar resource is active, and another when it's not. Then there will be entire days — like during May's unusual spring Nor'easter — where solar energy barely contributes to the system at all. All of this means that ISO-NE has had to become more sophisticated in its forecasting in this dynamic environment, *particularly as it relates to anticipated irradiance*, to ensure sufficient resources in the system for those cloudy days.

Where Else the Duck is Nesting

New England certainly has the most pronounced situation in terms of behind-the-meter resources, but it and California are by no means the only grids that are — or will be — greatly affected. A brief look at the interconnection queues (*Historically, only 19% of what's in the queue eventually flows power*, but it's still a useful indicator.) suggests significant levels of solar energy are on tap for various regions, with some much more affected than others.

Storage also increasingly enters the picture, both in the form of hybrid solar-battery projects and standalone ventures. A 2024 review of interconnection queues by region illustrates the sheer magnitude of the solar resource knocking at the door of other grid operators, such as MISO, PJM and ERCOT.

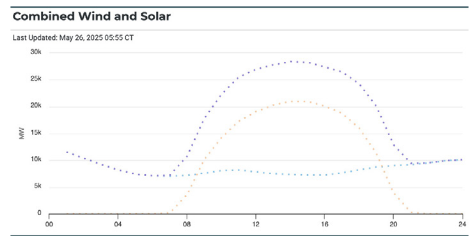
MISO and PJM are only beginning to be affected, as not much solar has been built out yet, but ERCOT already is an entirely different story. In Texas, almost 31,000 MW of solar capacity and nearly 40,000 MW of installed wind generation populate the system, up from *14,000 MW of solar and 36,000 MW of wind* just two-and-a-half years ago.

Renewables are so meaningful there that ERCOT forecasts the combined output of wind and solar daily. Some days, the tandem output resembles a cowboy hat, while other days it looks more like a derby.

Here, too, prices tend to soften increasingly by mid-day as Apollo's chariot ascends higher into the sky. A classic example of that effect would be May 14, when record demand occurred and yet prices did not soar into the stratosphere.

What Subsidies and Policies Give, They Also Can Remove

In recent years, solar energy has benefited from a flood of low-cost panels imported from Asian countries with minimal tariff barriers. This dynamic, combined with fairly generous federal tax policies, was topped off in some areas by generous state policies as well. That landscape has shifted recently. Steep tariff barriers have been erected on imports coming from the four countries from which the U.S. recently imported about 80% of its solar modules, and those *tariffs range from 41 to over 350%* on some of the larger Chinese-based companies that export most of the panels.



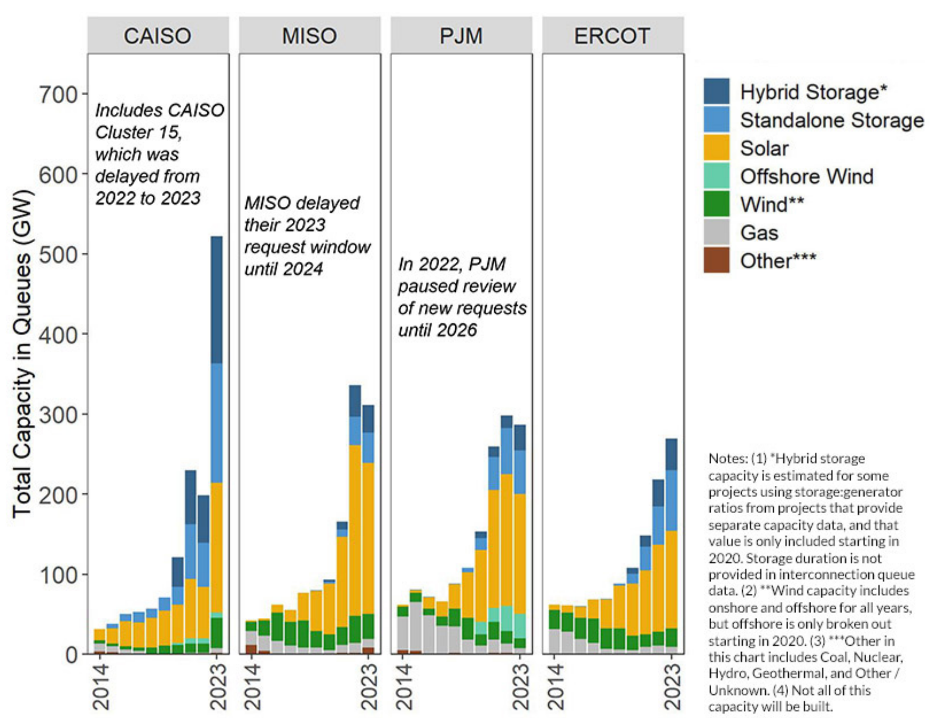
ERCOT

Perhaps even more critically, the U.S. House just narrowly voted to strip the investment tax credits from renewables nearly immediately. That legislation now goes to the Senate, where it is expected to be modified to some degree, though nobody knows quite how this will play out.

Meanwhile, at the state level, California has retreated recently from some of its most generous supports for rooftop solar, significantly reducing economic prospects for investors in on-site solar, with perhaps even more changes to come. Massachusetts — the key supporter of the New England duck — also has rolled back its most generous subsidies in recent years. And Texas just narrowly avoided a major legislative shift that would have dramatically eroded the future potential of solar.

This rapidly evolving political landscape invites the obvious question: "In the absence of significant subsidies, what would a future state look like?" At this point, with so much uncertainty in the air, nobody can say for sure. But the duck certainly is feeling its feathers ruffled.. ■

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



Lawrence Berkeley National Laboratory

Big Beautiful Expensive Uranium

By Steve Huntoon

Steve Huntoon

President Donald Trump issued four executive orders on nuclear power in late May, bizarrely bragging that this number of executive orders is twice the number of new nuclear plants *started in the U.S.* since 1978.

Say what? We haven't built new nuclear plants over the past 50 years (other than the Vogtle disaster) because they haven't made any *economic sense*, as I discussed *years ago*.

One of his executive orders directs a program for installing nuclear reactors at critical defense facilities, based on *the claim* that nuclear reactors can deliver resilient, reliable power to these facilities.

Trump's claim is wrong and misleading for many reasons.

Reason No. 1: Nuclear reactors cannot provide resilient, reliable power to defense facilities. As FERC has observed, in the event of an outage on the grid the nuclear reactor has to shut down and cannot restart until grid power *is restored* (page 44).

And as 41 transmission owners in PJM *recently said* to FERC: "Further, load that is co-located with a nuclear unit depends on services such as load following, voltage support, black start and other ancillary services that will be and can only be delivered over the grid. Nuclear units cannot move their output up and down from moment to moment to match variations in the load, and because the nuclear units cannot provide these services, they must instead be provided through connection to the grid" (page 13). Thus, nuclear reactors would contribute 0.0 reliability value to critical defense facilities.

Reason No. 2: Critical defense facilities already have *backup power*, generally on-site diesel generators. Thus, nuclear reactors would be superfluous.

Reason No. 3: A total of 87% of defense facility outages are due to problems on the distribution systems *inside the bases*. Thus, a nuclear reactor outside a base would provide 0.0 reliability value relative to such outages.

Reason No. 4: Nuclear reactors have lengthy refueling outages and obviously couldn't provide power during such outages.

Reason No. 5: If nuclear is to have any hope of commercial viability — which it doesn't have *for reasons* I've given —then it has to achieve economies of scale through modular production. Since every defense facility has its own unique power needs, that means every nuclear reactor for a given defense facility would need to be unique, thus defeating the only conceivable purpose of having taxpayers subsidize this Trump program.

Plant Vogtle Units 1-4 are shown in March 2024. | *Georgia Power*

Why This Matters

Steve Huntoon says that Trump's extra 300 GW of nuclear means each of us, as taxpayer or electric consumer or both, would lose $1,000 every year.

Defense facilities are only one aspect of Trump's four executive orders, which collectively are intended to increase the U.S. nuclear fleet from today's 100 GW to 400 GW *by 2050*.

What's that going to cost us? If we take the Ontario SMR cost per reactor (excluding the most expensive first unit) of $3.5 billion, optimistically assume no cost overruns, and divide by the SMR capacity of 300 MW, we get $11.5 million/MW. If we plug that capital cost into the Lazard capital cost range, it interpolates to $181/MWh in the *levelized cost of energy range* (page 38).

That is an excess of $143/MWh over the $38/MWh average *cost of generation* in PJM (Figure 3, transmission costs excluded). At nuclear's 90% capacity factor, Trump's 300 GW would translate to 2.6 million GWh/year, or 2.4 billion MWh/year, and thus into excessive costs of $343 billion/year for the U.S. overall, and an average excessive cost of $1,000/year for each of us. Please note that this would be a total "own goal" relative to the U.S. Energy Information Administration's base case for 2050, which has nuclear output and electric customer costs *essentially unchanged* from today.

Simply put, Trump's extra 300 GW of nuclear means each of us, as taxpayer or electric consumer or both, would lose $1,000 every year.

Now that is one Big (Not So) Beautiful Bill! ■

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

Trump Replacing FERC Chair Christie with Laura Swett

Laura Swett | *Vinson & Elkins*

FERC Chair Mark Christie's tenure running the commission is coming to an end, as news broke late June 2 that President Donald Trump plans to nominate Laura Swett of Vinson & Elkins to replace him.

"I learned this evening from a media inquiry that President Trump has appointed Laura Swett to replace me when my term expires," Christie *posted* on X. "I congratulate Laura and wish her the best. I will remain in office for a few weeks after June 30 to help get key orders out."

Law360 first reported the nomination, which had not been officially announced by the White House by press time.

Swett has previous experience at FERC serving on the staff of Chair Kevin McIntyre and former Commissioner Bernard McNamee, both Trump nominees in his first term. She also worked at the Office of Enforcement, according to her LinkedIn page.

Former FERC Chair Neil Chatterjee, who overlapped with both Swett and Christie on the commission, *called* the news bittersweet on X.

"I adore Laura Swett and believe she will be an excellent FERC chair (if given the chance by OIRA and OMB)," Chatterjee said, referencing the White House's Office of Information and Regulatory Affairs and Office of Management and Budget. "But Christie is a patriot; all he did was run the agency well. He's a veteran who has dedicated his life to serving America. He deserved better." ■

— James Downing

FERC Resource Adequacy Conference Comes with Markets at a Crossroads

By James Downing

FERC will hold a two-day *technical conference* June 4-5, where it will look at resource adequacy issues in the ISOs and RTOs, with most of the focus on those with capacity markets.

Capacity auctions in PJM and MISO have generated headlines recently as both markets face narrowing supply-and-demand balances that have led to spiking prices and yet another round of changes, which have been nearly constant since the capacity markets were created.

"The problem with the capacity market and the reason there's all this tinkering is there's literally hundreds of parameters that make a big impact on the prices and the quantities," Forward Market Design founder Peter Cramton said in an interview. "And people care enormously about those prices and quantities, and so they argue about them endlessly. So, in essence, capacity market has been troubled by this constant stakeholder debate about this effectively moving money from one side of the market to the other."

Cramton previously was an independent director on ERCOT's Board of Directors.

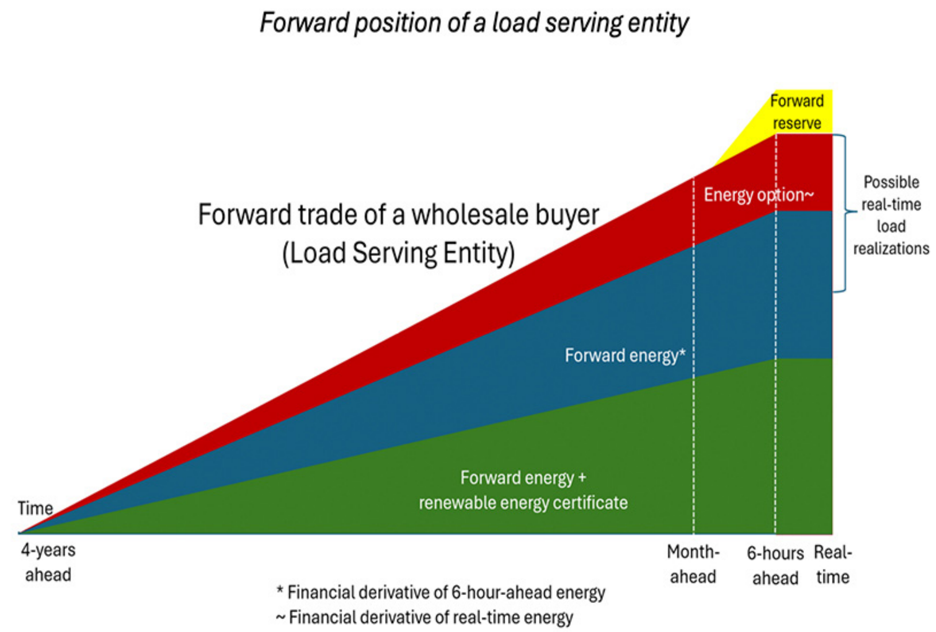
Forward Market Design filed *comments* in the tech conference's docket (*AD25-7*) outlining a major overhaul to organized markets that would scrap the capacity auctions and replace them with "forward energy markets."

The concept could be readily implemented by ISO/RTOs because it does not require changing their core systems for the day-ahead and real-time markets, the company said.

"Unique prices and quantities that maximize total welfare are calculated hourly for all forward products," it added. "This lets market participants trade gradually over tens of thousands of auctions to establish desired positions in forward energy and energy options before day-ahead is reached. Their positions can be adjusted based on the latest information and the consensus views of market participants with intuitive trade-to-target strategies."

When the capacity markets were first developed, the trading technology was not as effective as it is today, Cramton said.

"This new approach is really focusing on the fundamental problem that the natural sellers and natural buyers have to deal with, and that is to establish positions to best manage needs and risks," he added. "And the way this happens in the forward energy market is the system operator conducts an hourly auction for highly granular energy and energy option products. This is done with this new trading technology, flow trading, which is effectively what we already do today in the day-ahead and the real-time market."



A graph from Forward Market Design showing a hypothetical market participant's forward position in its forward energy market concept | *Forward Market Design LLC*

Why This Matters

FERC has held other technical conferences looking at ISO/RTO issues, and some of those have led to major rulemakings. Resource adequacy, however, has been one issue that the commission has historically left to the regions, so any changes in this process are likely to follow suit.

Instead of trading once or twice a year in capacity auctions, market participants can trade much more frequently and make constant adjustments to their positions over time, Cramton said. Forward hedges can be locked in gradually over time, helping participants manage risk and limit trading costs.

Capacity prices are high because of tightening supply and demand balances, which makes sense, but the overall cost is very high because there is a huge quantity of megawatt-days trading at that high price, Cramton said.

"That's what the forward energy market avoids by trading every hour rather than trading once a year," Cramton said. "So, when you're trading every hour, you may have this disequilibrium, and the prices are very high momentarily, but very small quantities are transacting many orders of magnitude smaller."

That still produces the all-important price signals to guide investment, but because of the smaller amounts being traded, the actual money involved will not lead to price spikes for consumers once the capacity year starts.

"Prices are changing gradually, and to the extent that the actions are taken to address the shortfall that's leading to the high prices, then the prices will fall over time as supply responds," Cramton said.

Replacing capacity markets with forward energy markets would represent a major change in organized markets, and Cramton's endorsement makes it an option worth considering, Copper Monarch's Vincent Duane, a longtime former PJM executive, said in an interview. But that is only one of the long-term options on the table.

"The commission is trying to explore what types of alternatives might sort of break the logjam of increased costs of supply versus the sort of affordability crisis," Duane said. The market design can continue to be tinkered around the edges; it could be knocked down and rebuilt; or it could be replaced with something entirely different.

The recent return to demand growth has come at a time when the cost of building power plants has gone up, with combined cycle rising from $1,000/kW about five years to $2,500/kW today, Duane said.

"The capacity market printed a price of about $280.60/MW-day the last time around," Duane said. "But that doesn't translate into what it's going to cost to incent new investment, which, of course, is desperately needed."

FERC Chair Mark Christie is not tied to the organized markets in the way many of his predecessors were, having published an article suggesting it was time to move on from the single clearing price model that is fundamental in ISO/RTOs. (See *FERC's Christie Calls for Reassessment of Single Clearing Price*.)

"Does it make sense in this day and age with the very different technologies that we now have, not to mention the ages of these technologies, to treat them all, from a capacity market perspective, as just another megawatt, as another megawatt, as another megawatt," Duane said. "And I think he's got a serious question in mind as to whether that makes sense."

Paying some supply more than others might be a way to get around the fact that the current systems' prices are politically unviable, but still not high enough to attract the needed wave of investment in new power plants, Duane said.

A key input to capacity prices is the load forecast. The markets need to clear enough capacity to meet future demand, plus a reserve margin, and forecasters face new uncertainty from the growth in large loads. The Electricity Customer Alliance and other customer groups wrote a letter May 30 to all four FERC commissioners ahead of the technical conference, saying FERC should ensure that best practices in load forecasting are being used.

The alliance includes some of those new large loads along with everyday mass market customers, and the letter's co-signers included the Electricity Consumers Resource Council and the National Association of State Utility Consumer Advocates.

"We cannot meet these national security imperatives … without more confidence in load growth forecasts, greater transparency and standardization in how forecasts are constructed, and clearer lines of communication among state and federal regulators, transmission operators, generators, load-serving entities and customers as forecasts are adjusted," the letter says. "Customers face significant reliability and cost risks when load growth forecasts and projections are uncertain and not transparent."

Looking into where current practices are incomplete or inaccurate and identifying best practices are important steps to protecting customers from reliability risks if forecasts are too low, or paying for stranded costs if they are too high, the letter says. "The commission is uniquely positioned to convene the states, industry and customers to examine load forecasting practices, given the impact of these practices on matters in the jurisdiction of both the commission and the states." ■

Energy Department Staff Cuts Just Getting Started

By James Downing

The Forrestal Building in D.C., home of the U.S. Department of Energy | *DOE*

The U.S. Department of Energy is poised to lose thousands of employees this year through early buyouts and other mechanisms, but the cuts are heavier in certain offices.

Cutting down the size of government is a major policy goal of President Donald Trump, as stated in a memo from the White House's Office of Management and Budget and the U.S. Office of Personnel Management issued about a month after he took office.

"The federal government is costly, inefficient and deeply in debt. At the same time, it is not producing results for the American public," the memo said. "Instead, tax dollars are being siphoned off to fund unproductive and unnecessary programs that benefit radical interest groups while hurting hard-working American citizens."

The memo called on federal agencies to submit "agency [reduction in force] and reorganization plans that include a "significant reduction" in full-time employees, lower budgets and "better service for the American people."

The full effects of that process are still being played out, with the deferred resignation program that many employees have signed up for not being final until the end of September. The law firm Mintz *said* that up to 5,000 employees at DOE alone could leave, which is out of a total workforce of around 16,000, according to the Equal Employment Opportunity Commission.

In testimony before the Senate Appropriations Committee on May 21, Energy Secretary Chris Wright said only a small percentage of employees had left the department.

Why This Matters

DOE has seen some staff cuts already, especially in areas focused on Biden-era policies, but with a deferred resignation program going into full effect in September and other reductions being considered, many more cuts are on the way.

"We are looking at larger reductions and … we have offered voluntary plans and programs for people to be compensated by the government as they transition to another career," Wright said. "We've done this slowly, carefully, with a lot of engagement with people and while looking at how to restructure our department. So, the ultimate reduction in workforce will be larger than it's been today."

The Federal Reserve Bank of St. Louis *estimates* that total federal employment has fallen from 3.015 million in January to 2.989 million at the end of April, which is still above January 2024 federal employment levels.

Speaking during a webinar in May put on by the World Resources Institute, where he is a senior fellow, former DOE Loans Program Officer Director Jigar Shah said some of the smartest people at DOE "were forcibly told to resign" over the previous couple months.

"So that expertise is gone," the former Biden administration official said. "Even if they wanted to figure out a nuclear renaissance, those people decided to take the early retirement program; the same with geothermal; the same with advanced battery storage. So they're not there to do that planning."

Shah listed his old office along with the Office of Clean Energy Demonstrations, the Grid Deployment Office, and the Office of Manufacturing and Energy Supply Chains as being particularly hard hit by staff cuts.

"If you have a new technology right now, and you go to the Department of Energy … I don't think there's actually anyone to talk to over there to help you with commercialization of your technologies," Shah said.

Lasting Impact

While administrations and their policies do come and go, the firings will be difficult to rewind if in four years a new president wanted a more active DOE.

"It is possible, but it's going to be very difficult," another former DOE official said in an interview. "You're going to need to have some kind of authority, from either the administration or Congress, that allows you to hire much more quickly than the normal civil service hiring rules have allowed you to do."

Even if hiring can be sped up, many of the employees let go or who left because of new requirements, such as return-to-office, were young and doing their first stint in public service, the official added. Their trust in the system will need to be rebuilt, they said.

The National Energy Technology Laboratory in Pittsburgh has not been hit as hard as some of the offices that were implementing key Biden-era policies, but about 100 employees have taken the deferred resignation program, said American Federation of Government Employees Local 1916 President Lilas Soukup.

"Obviously it's excruciating to lose about 15 to 20% of your workforce and not [be] able to replace them," she said.

A hiring freeze is in place until July 15, and it could be extended. Additionally, new rules only allow departments to hire one employee for every four who leave, Soukup said.

NETL has different focuses, and those dealing with solar energy are being reduced by the Trump administration. But it also works on fossil fuels, so Soukup said hopefully some of the staff losses could be offset by having her members switch to other programs.

While NETL — as well as the Department of Health and Human Services, whose Pittsburgh-area employees Soukup also represents — have not faced the same cutbacks as other parts of DOE, she worried about the long-term impacts of the staff cuts on public service.

"Who's going to want to take and work for the government after all of this fiasco is over with?" she asked.

DOE Reorganization Goes Beyond Staffing

DOE did not respond to requests for comment on its staff cuts, but on May 30, it put out a press release highlighting the shift in its direction under President Trump and Secretary Wright.

While the press was regularly bombarded with releases on funding authorized by DOE under President Joe Biden, the department trumpeted $3.7 billion in savings from 24 canceled projects.

"While the previous administration failed to conduct a thorough financial review before signing away billions of taxpayer dollars, the Trump administration is doing our due diligence to ensure we are utilizing taxpayer dollars to strengthen our national security, bolster affordable, reliable energy sources and advance projects that generate the highest possible return on investment," Wright said in a statement. "Today, we are acting in the best interest of the American people by canceling these 24 awards."

Of the canceled projects, 16 were approved between Election Day in November and Trump's inauguration Jan. 20, and they were primarily for carbon capture and storage projects.

The cuts came under criticism from the American Council for an Energy Efficient Economy, which argued they go against the goal of reshoring manufacturing.

"This program could have been a centerpiece of achieving the administration's goal to bring manufacturing back to the United States," ACEEE Executive Director Steven Nadel said. "Choosing to cancel these awards is shortsighted, and I think we're going to look back at this moment with regret. Locking domestic plants into outdated technology is not a recipe for future competitiveness or bringing manufacturing jobs back to American communities." ■

Interregional Transmission Would Improve Resource Adequacy, ACEG Report Argues

By James Downing

Interregional transmission can help address resource adequacy concerns around the country, according to a *report* released by Americans for a Clean Energy Grid and Grid United ahead of FERC's two-day technical conference. (See *FERC Resource Adequacy Conference Comes with Markets at a Crossroads*.)

"The last several Summer Reliability Assessments from [NERC], including this year's, continue to demonstrate resource adequacy risks facing the power system given hotter summers, load growth and an aging generation fleet," said co-author Adria Brooks, director of transmission planning for Grid Strategies. "This report demonstrates yet another benefit of interregional transmission, adding to a growing list of reliability and cost benefits. We have to stop ignoring the value of interregional transmission and instead create mechanisms to build it."

Interregional transmission offers value because different regions have different resource mixes and their peak demand is often at different times, the report says.

| Matthew T. Rader, CC BY-SA 4.0, via Wikimedia Commons

"Interregional transmission allows capacity resources to be shared between regions with noncoincident demand," the report says. "The interregional transmission assets themselves tend to be available nearly 100% of the time. Consumers benefit from this sharing of reserves, both in terms of improved reliability and reduced costs. These reliability and economic benefits are heightened during grid stress events."

To move forward with more interregional transmission investment, the industry will need to integrate capacity value into its resource adequacy assessments, which can be calculated using standard industry methods such as effective load-carrying capacity (ELCC).

"ELCC considers the difference in loss-of-load expectation (LOLE) — or any other RA metric — for the system with and without the supply resource and calculates how much additional load the resource can serve to return the system to the standard LOLE baseline of one day in 10 years," the report says. "This method has been successfully applied in several recent transmission facility or resource adequacy studies to derive the capacity value of several interregional transmission lines both in the United States and abroad."

System planners historically have not calculated the LOLE reduction from an individual transmission line and converted it to a capacity value. But most have calculated the cut in LOLE associated with the current fleet of interregional lines, which is called "external assistance," "tie benefits" and "firm and non-firm imports" in different regions.

Without a benefit that load-serving entities can credit to their resource adequacy obligations that indirectly provides value to transmission developers, or direct payments to transmission for its resource adequacy contributions, the industry will have fewer incentives to build interregional lines. The valuation and compensation can be done for either fully regulated transmission or merchant lines.

The report argues that considering the benefits of lower planning reserve margins from interregional lines will not worsen reliability; it would represent a cut in the amount of capacity needed to maintain resource adequacy. Those benefits can even come from non-firm imports, with grid planners using a probabilistic treatment of available imports to avoid overcounting such resources.

Why This Matters

With resource adequacy concerns growing, ACEG's report offers one possible solution to help the industry meet growing demand reliably and affordably.

"All regions we surveyed include firm imports from neighbors in their resource adequacy assessments, but only a handful also consider the contribution of non-firm imports," the report says. "Those that do incorporate non-firm imports rarely accredit the interregional transmission [that] enables non-firm imports with a capacity value for their contribution to resource adequacy."

Non-firm imports are a way to quantify the "net load diversity" between regions, such as when one region faces a shortage but its neighbor has excess supply.

"Non-firm imports are a vital resource to the system, allowing operators to keep customers' lights on even when there are no more internal resources to call on for support," the report says. "However, these imports are not consistently incorporated into resource adequacy assessments. This omission may result in the over-procurement of capacity resources internal to the planning region to meet the planning reserve requirement, raising costs for ratepayers."

At the simplest level, planners can look at historic imports to determine how many non-firm imports can be included in LOLE studies. Doing that seasonally, or only during tight-capacity periods, provides more confidence that external support will be available in the future. ■

Pathways Initiative Seeks $7.1M to Fund RO

By Henrik Nilsson

The West-Wide Governance Pathways Initiative's Launch Committee estimates it will cost about $7.1 million to launch the independent regional organization (RO) that eventually will oversee energy markets in the West, staff said during a May 30 presentation, while noting federal funding for the effort is uncertain.

The budget is divided into three categories: preparation, formation and implementation. The estimated total cost for all three phases is about $7.1 million, including a 10% contingency cost, said launch committee member Jim Shetler, general manager of the Balancing Authority of Northern California.

The draft budget runs from Jan.1, 2025, to Dec. 31, 2027, when tariff funding takes effect for the RO. It includes costs for activities like project management, legal services, hiring an executive director and general counsel, and finalizing a draft tariff and service agreements.

However, the committee has yet to receive confirmation on whether the U.S. Department of Energy plans to issue nearly $1 million in funding. Pathways received a commitment under former President Joe Biden's administration to underwrite the committee's efforts to establish the RO to oversee CAISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM). (See *Feds Pause $1M Pathways Initiative Funding, Group Leader Says*.)

The award was issued through the Pathways Initiative's philanthropy adviser, Global Impact, which the group's Launch Committee partnered with earlier in 2024 to secure outside funding for its operations, which so far have been supported by donations — and volunteered staff — from its participants.

Why This Matters

Ensuring sufficient funding will be key to seating an independent five-member board by July 2026 to negotiate with CAISO.

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President Donald Trump's administration on Jan. 27 paused all federal grants and loans, according to a memo issued by the White House's Office of Management and Budget.

"We are still looking to try to engage to see if we can get a DOE grant, but we're not assuming that that will be the case," Shetler said.

Instead, the committee seeks donations from stakeholders to support the effort, Shetler added.

"I'll just let you know I've been starting some initial dialog with the utilities that have indicated support for EDAM, and I'm not suggesting the utilities would support all of the $7.2 million, but at least we have started dialog around how we might support that," Shetler said.

Kathleen Staks, executive director of Western Freedom and the Launch Committee's co-chair, also provided an update on the RO's board members, stating that the committee hopes to seat a board by July 2026 and no later than January 2027. (See *Pathways Inches Closer to Seating RO Board*.)

Per the committee's draft proposal, the board will have five members, with two additional seats added after FERC approves the tariff changes and RO funding is secured.

The initial board will consist of independent members that will negotiate with CAISO, Staks said. She noted the board "would not yet have any authority over the markets because that authority change does not happen until FERC approves the tariff change."

The five initial members would serve until the RO tariff goes into effect, and service during this period would not count toward the members' term limits, according to the committee's proposal.

The committee has proposed that when the RO is fully implemented and has a seven-member board, two of the seats would be one-year terms; two seats would be two-year terms; and three of the seats would be full, three-year terms.

Staks noted that seating the five-member board in July, as opposed to a smaller board or seating at a later date, "will create a pretty significant increase in our budget."

But the committee did not want the budget to be a "limiting factor for the important role that this independent body will play as we move forward," Staks said.

"We decided that we would prioritize having some of these independent board members in place earlier, so that there really is that separation and independence for the negotiations with the CAISO," Staks said. ■

Amended 'Pathways' Bill Boosts — and Complicates — Calif. Protections

Changes Reflect 'Delicate Negotiation' Between State, Rest of West Around RO, Legal Expert Says

By Robert Mullin

The latest version of California's "Pathways" bill strips out a previous amendment that would have given state regulators authority to order utilities to withdraw from the West-Wide Governance Pathways Initiative's "regional organization" (RO) under certain circumstances.

But that doesn't mean the bill has been slimmed down. Just the opposite, in fact.

Instead, a newer iteration of the bill replaced that provision with a lengthier one prescribing a more complicated process for undertaking the same action, while adding a slew of other conditions intended to protect California's policies and ratepayers.

"In short, this new provision reflects the delicate negotiation between California and the rest of the West as they figure out how to marry their energy systems," Lincoln Davies — professor of law and executive director of energy, resource and environment programs at the University of Utah's S.J. Quinney College of Law — told *RTO Insider* in an email.

"This should be expected, and this bill is still a strong step in the right direction. It would ensure RO independence but give California assurance it can exercise its sovereign power to protect its citizens," Davies said.

Senate Bill 540 emerged from the Senate's Appropriations Committee on May 23 in a 4-1 vote recommending that the full house pass the legislation as amended, but the exact content of the amended bill remained a mystery until the Legislature printed and posted it May 28. (See *California's 'Pathways' Bill Heading to Senate Floor*.)

The newest version removes language the Senate Judiciary Committee added in April to address the concerns of constituents and lawmakers who fear that CAISO's membership in the proposed independent RO could provide a backdoor for the Trump administration to compromise California's ambitious environmental and clean energy policies. (See *California Lawmakers Seek to Trump-proof Pathways Initiative Bill*.)

To prevent that outcome, the Judiciary Committee inserted an amendment stipulating that the California Public Utilities Commission could direct its jurisdictional utilities to withdraw from the RO if the new entity's rules were to become "detrimental to California consumers."

Floor of the California Senate | *Shutterstock*

Why This Matters

The final language in California's 'Pathways' bill will dictate whether the state can produce a law that helps establish a 'regional organization' that's acceptable to the state's interests and those in the rest of the West.

The amendment also mandated withdrawal if the state's renewable portfolio standard is "held invalid by [a] reviewing court on claims of impermissible discrimination" or if the Trump administration — or future administrations — invoke emergency powers that require California to subsidize fossil fuel generation.

That amendment has been deleted, only to be replaced by a more complex one that outlines the creation of a new Regional Energy Market Oversight Council designed to ensure "that participation in a regional energy market serves the interests of the state."

The council would consist of the CPUC president; the chair of the California Energy Commission; the chairs of the Senate Committee on Energy, Utilities and Communications and Assembly Committee on Utilities and Energy; and the state's attorney general, with the AG serving as chair.

It would be charged with approving "initial participation" in the RO by California's "electrical corporations" and load-serving entities and, "at any point" after that approval, determining whether those entities "should be required to withdraw from an energy market governed by the independent regional organization" after convening a public meeting on the matter.

In its capacity for making RO withdrawal decisions, the council would also be responsible for reviewing the RO tariff both before and after FERC approval, as well as for monitoring any "subsequent actions" related to the market that might:

- weaken or invalidate California's RPS;
- require the state, CAISO or any LSE to procure or subsidize fossil fuel generation located outside California; or
- result in "adverse impacts on California's resource planning, procurement, environmental, reliability or other applicable public interest policies."

The amendment also makes the council respsonsible for protecting ratepayers by authorizing the new body to order utilities to withdraw from the RO if the organization or the federal government take measures that cause the cost of California's regional market participation to exceed benefits over a two-year period.

The council could also order withdrawal if the RO fails to fully compensate California ratepayers for CAISO's costs to provide the RO with "any services, facilities, equipment and property, including intellectual property," or if the RO doesn't hold both ratepayers and the ISO "harmless" for legal claims arising from the operation of the regional market.

The new amendment further prohibits CAISO from modifying its own tariff in relation to the RO without the council's approval.

Getting Hitched

Sources familiar with the California legislative process have told *RTO Insider* that the Appropriations Committee's process of adding amendments to bills is something of a black box — and that appears to be the case for SB 540.

One source close to the SB 540 effort said it was unclear exactly which lawmakers added the amendments, or why. The office of the bill's sponsor, Sen. Josh Becker, had not responded to questions as of press time.

But Davies said he thinks the new provision seeks to achieve three objectives.

"First, it creates a checkpoint for California electricity providers for entry or exit into these new markets. Under the prior version of the bill, this was left mostly to self-execution, with an express reservation of PUC authority to order withdrawal. Now, companies need to ask 'mother, may I?' to get in or out of the markets," he said.

"Second, it spreads authority across multiple entities rather than concentrating it in the CPUC. The prior withdrawal provision left sole authority to the CPUC to act. Now the council would have representatives from multiple agencies, both chambers of the legislature and the attorney general."

The third objective could be the most fundamental, according to Davies, because it aims to allow California to maintain control over its policies while still providing for independent governance of CAISO's markets.

"This is understandable, particularly given how federal energy policy is developing right now, including the White House specifically naming California energy policy as a target for federal action in executive orders," he said.

Davies noted that "any bill that erodes the independence of the new RO is certain to crater a broader Western market," and that the widest possible market is in the interest of all participants, including California.

"At some point, of course, everyone will need to end the courtship and just decide to get hitched or not," he said. "This bill should make that possible — to the benefit of California, the climate and the broader West. Anything that moves more control to California likely will not." ■

BPA Predicts Energy Deficits Over the Next 10 Years

By Henrik Nilsson

The Bonneville Power Administration predicts even steeper energy deficits among its network of dams under firm conditions compared to predictions last year, according to the agency's annual "White Book" study.

BPA's Pacific Northwest Loads and Resources Study, or the White Book, was issued May 29. It covers a 10-year period and provides predictions for the federal power marketer's loads and resources, as well as the entire region's retail loads, power supply obligations and resources.

The 2025 *White Book* finds that under firm conditions, the federal system would have annual energy deficits between 2026 and 2035, ranging from deficits of 426 average annual megawatts (aMW) to a high of 1,012 aMW.

"Overall, these annual energy deficit projections are more than those projected in the 2024 White Book," according to the study. In 2024, the White Book projected deficits ranging from 79 aMW to 303 aMW.

The 2025 study also found that under median water conditions, the federal system could have a surplus ranging from 911 aMW to 364 aMW. The Northwest relies heavily on hydropower generation, which is notoriously difficult to predict and can fluctuate dramatically from year to year.

"The federal system surplus/deficit forecasts generally have a positive relationship with water conditions," the report says. "Better water conditions generally yield more surplus overall. For example, the annual energy surplus can increase by over 4,000 aMW under better water conditions, while monthly surplus or deficit position can vary by over 5,500 aMW within the same year."

Meanwhile, the entire Pacific Northwest could have an energy surplus of 960 aMW in 2026 under firm water conditions, but this could drop rapidly to a deficit of 3,026 aMW by 2034. Under median water conditions, however, the region could have surpluses until 2032, according to the report.

"This result was mainly driven by the increasing retail loads," the report stated. "Overall, the annual energy surplus/deficit position projections are more surplus than forecasts from the 2024 White Book until the out years of the study period. Under median water conditions, the PNW region would begin to see energy deficits in the out years."

BPA's White Book follows the Northwest Power and Conservation Council's (NWPCC) initial 20-year forecast released in April. (See *NWPCC's Initial Demand Forecast Sees Sharp Growth for NW*.)

BPA headquarters in Portland, Ore. | *Bonneville Power Administration*

Why This Matters

Like every region in the U.S., load growth is expected from electric vehicles and data centers. But the Northwest relies heavily on hydropower generation, which is notoriously difficult to predict and can fluctuate dramatically from year to year.

Energy consumption in the region has hovered around 20,000 to 22,000 aMW since 2010, according to NWPCC. But energy demand could skyrocket and reach between 31,000 and 44,000 aMW by 2046, with the largest growth expected from electric vehicles and data centers, NWPCC found.

BPA noted in the White Book that "many factors contribute to the uncertainty of the longer-term resources outlook for the region, such as resource retirements and development, resource adequacy and the efforts surrounding it, and other federal and state policy mandates. As with resources, there is also much uncertainty with loads including the potential for electrification and data centers coming online."

"While regional analysis shows surpluses in the first two years of the 10-year study period with rapidly rising deficits in certain parts of the years following that period, BPA analysis shows periodic deficits for the entire study period," BPA spokesperson Doug Johnson told *RTO Insider*. "Rapidly growing load forecasts and subtle changes in water volume and runoff over the period account for the growing deficits."

Johnson pointed out that forecast certainty declines "the deeper you get into the 10-year period."

"However, it looks like at some point during the study period BPA will likely need to secure the output of additional resources to meet its firm power obligations," he said. ■

Study Finds PSCo Would Gain More in EDAM than Markets+

Colorado Utility is Already Seeking Permission to Join the SPP Market

By Robert Mullin

A new study commissioned by the Environmental Defense Fund finds Public Service Company of Colorado (PSCo) would earn millions of dollars more in annual benefits from participating in CAISO's Extended Day-Ahead Market (EDAM) than SPP's Markets+.

The *study*, conducted by Aurora Energy Research, found EDAM could provide the Denver-based utility $11.2 million more in average annual savings from 2028 to 2040 compared with Markets+, rising to $13.2 million through 2060.

The analysis comes three months after PSCo, a subsidiary of Xcel Energy, asked the Colorado Public Utilities Commission for permission to join Markets+ and fund its share of the Phase 2 implementation stage of the market. (See *PSCo Seeks to Join SPP's Markets+*.)

Why This Matters

The study could carry some weight in the Colorado PUC's response to PSCo's request to join SPP's Markets+.

"It's important to recognize that not all markets are created equal," Alex DeGolia, director of state legislative and regulatory affairs at EDF, said in a May 27 statement accompanying the release of the study.

Like other prominent environmental organizations, EDF has advocated strongly for a single Western electricity market that pointedly includes California and rests on the existing framework of CAISO's Western Energy Imbalance Market.

"Coloradans deserve for this decision — which could have decadeslong implications for their utility bills, as well as the state's ability to meet its climate targets — to be informed by thorough, robust analysis. Recent analysis suggests that the Extended Day-Ahead Market is a clear winner among currently available options in terms of delivering both lower costs and more reliability to our state," DeGolia said.

In an email to *RTO Insider*, Joe Taylor, senior director of Western markets for Xcel Energy-Colorado, said the Aurora study "was very recently submitted in public comments in our application to join the

Average cost breakdown for PSCo under EDAM vs Markets+ DAM, 2028-2060

$Million/year

Metric	EDAM	Markets+	Delta (EDAM – Markets+)[1]	Average delta, 2028-2040	Average delta, 2041-2060
Production cost	857.4	862.3	(4.9)	(1.2)	(7.4)
Bilateral trading costs	231.9	227.0	4.9	0.2	8.0
Congestion revenue	(85.8)	(72.9)	(12.8)	(9.2)	(15.2)
Wheeling revenue	(5.5)	(5.1)	(0.4)	(1.0)	(0.0)
Costs less revenues	998.0	1,011.2	(13.2)	(11.2)	(14.6)

Aurora Energy Research

Markets+ market."

"We are taking part in that proceeding at the Public Utilities Commission and have not had the opportunity yet to review this document," Taylor wrote.

Breakdown of Benefits

In its February filing with the PUC seeking to join Markets+, PSCo said it was swayed by the SPP market's independent governance, greenhouse gas emissions tracking and accounting system, and benefits "overall and in relation to costs relative to the other markets studied, including EDAM."

It's unclear what impact the Aurora study might have on the PUC's response, but it could raise questions about PSCo's cost-benefit claim based on its examination of four metrics, including estimated production costs, bilateral trading costs, congestion revenues and wheeling revenues under both markets.

The study found that under EDAM, PSCo's average annual productions costs would be $4.9 million lower than in Markets+, in large part because the CAISO market would allow the utility to more significantly increase its use of wind generation and reduce its reliance on gas-fired generation.

Aurora also found that PSCo's participation in EDAM would bring increased use of its transmission system to facilitate energy transfers between EDAM members PacifiCorp and PNM, whose balancing areas border PSCo. Those transfers would translate into $12.8 million more in congestion revenues compared with Markets+, along with $0.4 million more in wheeling revenues.

The study does show Markets+ outperforming in one area: PSCo's bilateral trading costs in EDAM are expected to exceed those in the SPP market by $4.9 million, something largely attributed to "friction charges" for imports from the Western Area Power Administration's neighboring Rocky Mountain Region balancing area, which plans to join SPP's full RTO.

Aurora noted that, in modeling the Western Interconnection, the study considered transfer limits between BAs, basing its transfer capacity assumptions on both the historical record and assumptions about planned upgrades to interstate transmission capacity affecting Colorado, including three lines expected to begin service in 2032.

But even in excluding those planned interstate projects in the modeling, EDAM's benefits would exceed those of Markets+ by $4.2 million a year, the study found, while the EDAM benefits advantage would continue to increase with the additional inclusion of each project.

The study also found PSCo would be able to comply with Colorado's ambitious emissions targets under either market. State law requires utilities to reduce their emissions from retail sales by 80% by 2030 compared with a 2005 baseline and move to 100% clean energy by 2050.

"Emissions are similar between the two modeled scenarios for PSCo participation in EDAM and Markets+, given the capacity mix was held constant. Marginal differences in emissions are driven by variation in carbon intensity of imports and exports," the study says.

Aurora's study modeled the makeup of each market based on confirmed and likely commitments by participants. ■

BLM Proposes Accommodations for Greenlink North Line

Changes Would Exempt Corridor from Sage-grouse Restrictions

By Elaine Goodman

The Bureau of Land Management has proposed changes to three of its Northern Nevada resource management plans to accommodate NV Energy's 235-mile Greenlink North transmission project.

The proposed amendments would loosen restrictions for building near greater sage-grouse habitat and courtship areas known as leks.

The amendments were released along with BLM's final environmental impact statement for Greenlink North on May 27, opening a 45-day objection period. BLM expects to issue a record of decision for the project this year.

Greenlink North would be a 525-kV line connecting the Robinson Summit substation in northeastern Nevada to the Fort Churchill substation in the northwestern part of the state. The line would run parallel to U.S. Highway 50 and an existing 230-kV transmission line for most of its length.

Greenlink North will connect with NV Energy's existing One Nevada Line, a north-south line along the eastern side of the state, and Greenlink West, a 525-kV, 350-mile line under construction on the west side of the state, to form a transmission triangle around Nevada.

The project is aimed at increasing transmission redundancy, reliability and resiliency. It will facilitate access to state-designated renewable energy zones to help meet greenhouse gas reduction targets.

The project will also "increase northern Nevada's transmission import capacity required to meet the region's electric demand, grid reliability and [FERC] requests for service," according to the BLM document.

Greenlink West is expected to be in service by May 2027, and Greenlink North's expected in-service date is December 2028.

Plan Amendments

BLM's proposed resource management plan (RMP) amendments would designate a new utility corridor up to 3,500 feet wide on land where the Greenlink North project would be built. That would provide enough space to avoid electrical interference with the existing 230-kV line, the bureau said.

Under the amendment, the utility corridor would be exempt from requirements to stay a certain distance from sage-grouse leks. Roughly 100 miles of Greenlink North would be within a 3.1-mile buffer zone for ground disturbances around leks. The buffer requirement would impact geotechnical investigations, construction work, and operation and maintenance activities, BLM said.

Greater sage-grouse gather in areas known as leks where they perform displays as part of their courtship behavior. | *Shutterstock*

Why This Matters

The looser restrictions for building near greater sage-grouse habitat could accelerate construction of the 525-kV Greenlink North line.

"The transmission line's proximity to leks would be unavoidable," the BLM document said. "Exempting the BLM utility corridor from the lek avoidance buffers would ensure the viability of the utility corridor if future applications for energy transmission projects were submitted to the BLM."

The utility corridor would also be exempt from a seasonal restriction for activities in greater sage-grouse winter range, under the proposed amendment.

With seasonal restrictions in place for breeding, brood-rearing and winter habitats, 190 miles of the Greenlink North project would have only 45 days a year remaining for construction, from Sept. 16 to Oct. 31.

With the winter-range seasonal restriction removed, the construction season would run from Sept. 16 to Feb. 28.

Making Progress

The release of the BLM documents is the latest piece to fall into place for the Greenlink projects. (See *NV Energy's Greenlink West Poised for Progress in 2025*.)

Work has started at both ends of Greenlink West, NV Energy said in a March *project update*. In April, construction crews drilled the first holes for the project's transmission poles. Material yards have been established in strategic locations to reduce distance to construction sites.

NV Energy said it's been taking delivery of lattice and tubular transmission structures, conductor and shield wire for the transmission line, and high-voltage circuit breakers and steel support structures for the substation equipment. ■

CAISO Battery Storage Initiative Focuses on Outage Management, Nonlinearity

Issue Paper Outlines Possible Solutions amid Battery Boom

By David Krause

CAISO is moving ahead with a key initiative to resolve how battery storage resources function on the grid as the battery boom continues in the Golden State.

The ISO is prioritizing battery outage management enhancements, battery nonlinearity guidance and state of charge (SOC) clarifications in its storage design and modeling initiative that began earlier this year.

CAISO held a stakeholder meeting May 28 to address technical challenges associated with the increase in battery storage capacity on its grid, which has grown from 500 MW in 2020 to more than 11,000 MW in 2025.

CAISO's current outage management system has served conventional resources effectively but does not easily convey a battery's SOC limits, CAISO said in an issue paper. Storage resources face limitations and outage types not covered in the outage management system that are unique to storage resources, such as negative minimum energy outputs.

There is a lack of clarity around how battery resources can accurately represent their availability to CAISO using the existing outage management system, CalCCA said in comments to CAISO. Another stakeholder in the initiative, Vistra, asked CAISO to clarify reporting thresholds for a battery's SOC, specifically recommending the ISO add reporting requirements for changes that exceed 10 MW or 40 MWh, or 5% of registered values lasting 15 minutes or longer and within 60 minutes of discovery.

CAISO agreed with stakeholders about the need to align its outage management system with storage-specific outage types and characteristics. To do so, the ISO is considering implementing an outage card that can adjust a battery's availability, maximum load, maximum energy and minimum energy values on one card.

Nonlinearity Options

Another key concern addressed by the initiative is battery storage nonlinearity, meaning the concept that batteries charge and discharge energy nonlinearly. Nonlinearity complicates the modeling and control of battery storage resources, which in turn reduces a battery's responsiveness and dispatch capability, CAISO said in the issue paper. Nonlinearity is comparable to gas generators that may take time to ramp up to reach their maximum dispatch, CAISO said at the meeting.

As a battery approaches its SOC limits, its maximum and minimum energy output are "greatly affected, potentially hindering its ability to respond to grid demands," CAISO said. For example, a 100-MW battery storage facility might be able to charge or discharge only 50 MW at the extremes of its SOC.

BLM California

Why This Matters

Battery storage has become a key resource in California to ensure the state can meet its peak demand, but integrating the technology onto the grid brings new challenges.

"Nonlinearity is the area we got the most diverse comments," said Sergio Dueñas, CAISO storage sector manager, at the working group meeting. "Everyone is getting more and more comfortable with the idea of, 'Let's pursue a [solution] in the near term and then move to a more doable solution in the long term.'"

CAISO is considering four ideas to account for nonlinearity, one of which is to use outage cards that indicate the effects of nonlinearity on ramp rates and maximum energy outputs. Currently, some market participants might be communicating the impacts of nonlinearity through outage cards that do not include all of these characteristics, since nonlinearity is not explicitly called out in the outage management system, CAISO said.

As a near-term solution, CAISO favors participants including a comment noting that an outage is related to nonlinearity. This near-term guidance will allow for resources shown as resource adequacy (RA) resources to be evaluated in the context of the RA availability incentive mechanism (RAAIM), the ISO said. The RAAIM provides incentives or disincentives for resources to help ensure they're available for CAISO to meet reliability needs. If a battery resource is shown as RA and evaluated as RAAIM, then the battery would be accounted for according to its actual dispatch availability under instances of nonlinearity, CAISO said.

CAISO plans to publish a revised issue paper and hold another stakeholder meeting June 30. ■

WECC Report Highlights Larger Loads, Longer Emergencies

'State of the Interconnection' Shows Western Demand Growth at 20-year High

By Elaine Goodman

Peak demand in the Western Interconnection hit a record high of 168.2 GW in 2024, reflecting "early effects" of the growth in large loads such as data centers, according to a new WECC report.

Peak demand in the interconnection has grown 8.5% since 2015, when it was 155 GW. The 2024 peak demand, reached on July 10, was the fifth time in the past 10 years that a new record has been set.

Annual demand also set a new record in 2024 of 926,000 GWh.

"Demand growth is higher today than at any other time in the last 20 years," WECC said in its 2025 State of the Interconnection *report*, released May 22.

Large-load challenges have been the topic of WECC webinars in recent months, and the organization commissioned a *report* from Elevate Consulting on large load risks in the Western Interconnection. (See *IBR Lessons Can Guide Data Center Challenges, WECC Report Finds*.)

WECC's State of the Interconnection report highlights the large load experience of Arizona Public Service (APS), which expects its annual energy needs to grow by almost 24 GWh between 2023 and 2038. The utility attributes nearly 80% of that growth to data centers and large industrial and manufacturing facilities, especially semiconductor chip factories.

From 2023 to 2031, APS expects nearly 40% growth in its annual peak demand.

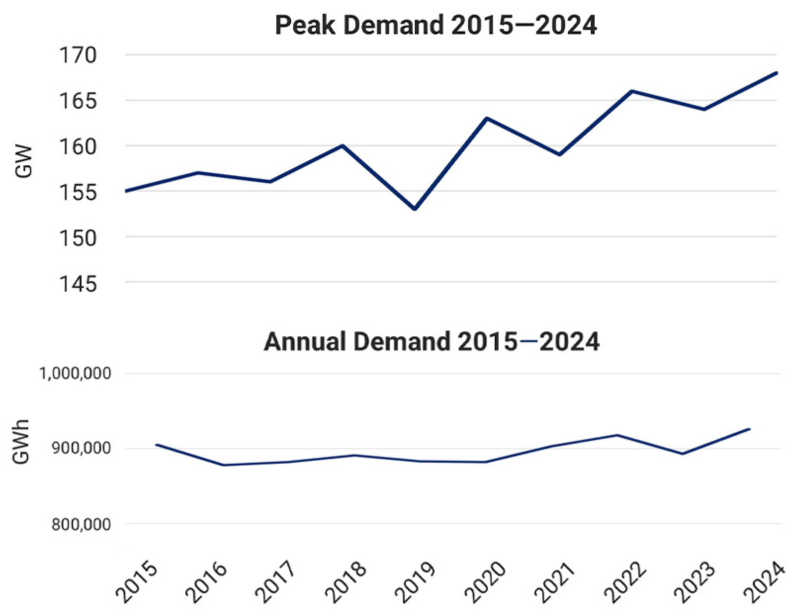
Forecasting Issues

The unprecedented growth in demand is creating forecasting challenges, WECC said.

At the interconnection-wide level, annual demand forecasts have been close to actual demand for the last five years, WECC said. But some balancing authorities seem to be better at forecasting than others, according to the report, which pointed to an unnamed BA that had forecasts averaging 32% over its actual demand in all forecast years. And forecasts from other BAs sometimes turn out to be less than actual demand.

"It could be a concerning indicator that demand forecasting practices vary widely," the report said.

To meet the growing demand, resources are being built at a faster rate. More than 24 GW of new resources were added in 2024, far more than the 10-year annual average of 7.4 GW. The 24 GW represented 80% of the new resources planned to be built last year.



| WECC

Why This Matters

WECC's 'State of the Interconnection' report finds the West will need to maintain a rapid pace of building new resources to keep up with burgeoning demand.

"The West will have to build at the 2024 rate at least to meet forecast demand," the WECC report said.

Of the new generation added last year, 5.5 GW was natural gas. About three-quarters of the new additions were inverter-based resources: 8 GW of solar, 3 GW of wind and 7 GW of battery storage. That brought the interconnection totals for solar, wind and battery storage to 44 GW, 39.3 GW and 16.7 GW, respectively.

The WECC report also tallied system events across the Western Interconnection.

The number of energy emergency alerts (EEAs) rose sharply, from 21 in 2023 to 30 in 2024. Last year's total included 18 Level 3 EEAs, the most serious of the three levels in which rolling blackouts may be deployed. Nearly half of those events took place in January 2024 during winter storms Heather and Gerri.

EEAs also lasted longer in 2024. EEA-1 events, in which energy conservation is called for, averaged 4.47 hours last year compared to 1.94 hours in 2023.

The average duration for all EEAs was 4.28 hours in 2024 compared to 2.47 hours the previous year.

"Extreme weather (variability and extreme temperatures) continues to be the biggest driver of EEAs across the interconnection as it leads to surging demand and the potential to impact generation," WECC said in the report. ■

WestTEC Tx Study on Track Despite Delays

By Henrik Nilsson

The Western Transmission Expansion Coalition (WestTEC) is on track to publish the first phase of its transmission planning study this summer despite some delays in finalizing the models that will underpin the study, coalition members said during a May 27 webinar.

The goal of the study is to produce transmission portfolios for 10- and 20-year planning horizons. Models related to both planning horizons have been delayed by a few months, Keegan Moyer, a partner at Energy Strategies and consultant for WestTEC, said during the presentation.

Moyer said the delays are not to be "totally unexpected" given the study's "scope and ambition."

"We were going to have results around now from the preliminary analysis," Moyer said. "The models are still being finalized, so we are expecting to have a better understanding of what we're seeing in the 10-year time frame in the next two to three months. We still think we're going to be roughly on time for the report focused on that 10-year horizon, which will be issued in the late summer, kind of early fall, time frame."

The 20-year horizon is similarly delayed but "overall on track for the project as a whole," he added.

The 10-year plan originally was scheduled to be published in August 2025 and the 20-year horizon study in September 2027.

The WestTEC study, jointly facilitated by the Western Power Pool and WECC, will address long-term interregional transmission needs across the Western Interconnection. The WestTEC Steering Committee unanimously approved the project's study plan in September 2024. (See *WestTEC Committee OKs Plan for 'Actionable' Tx Study*.)

The study will include a reference case based on anticipated trends in load growth, technology and policy in transmission planning. The reference case assumes a 2.2% annual load growth between 2024 and 2045.

The scenario planning subcommittee also is developing two separate cases, labeled "flux" and "core," to be included in the 20-year horizon, according to the study plan.

The flux case represents a high-growth scenario that reflects rapid changes in power demand and technology innovation in areas like artificial intelligence, wind, solar and energy storage. The annual load growth under the flux case is 3%.

The core case, meanwhile, includes a moderate-growth scenario with select technology breakthroughs and a 2% annual load growth, according to the May 27 presentation.

The technologies in the core case "are sort of advanced geothermal, nuclear, [small modular reactors], carbon capture, these types of technologies with a lower level of load growth and an assumption that there's some statutory delays," Moyer said.

"The goal with these two scenarios and the reference case is to create divergent futures," Moyer said. He added that "there are a wide range of futures that should definitely produce some interesting modeling results." ■

Stefan Andrej Shambora, CC BY-2.0, via Wikimedia Commons

Imperial Irrigation District Inks Agreement to Join CAISO Markets

Southern Calif. Publicly Owned Utility to Join WEIM, EDAM in 2028

By Henrik Nilsson and Robert Mullin

The Imperial Irrigation District (IID) has agreed to join CAISO's Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM), the ISO announced May 27.

CAISO said the publicly owned utility, based in Southern California's Imperial County, has signed implementation agreements and will begin participating in the markets in 2028.

In a separate announcement May 20, IID said its board of directors approved a $24 million budget amendment "to advance preparations for joining" WEIM and the soon-to-be-launched EDAM. The money will fund upgrades to the utility's control infrastructure, telecommunications, metering and energy management systems, according to the announcement.

"As a large public power provider in California, IID is pleased to join both the Western Energy Imbalance Market and the Extended Day-Ahead Market," Jamie Asbury, general manager at IID, said in a statement. "This is a significant step toward modernizing how we purchase and manage power, which will translate into savings for our ratepayers annually by giving us the ability to react much faster to energy market conditions. This also aligns IID more closely with emerging regional energy practices yet allows us to retain our independence as an energy balancing authority."

IID serves about 165,000 customers in service territory covering 6,611 square miles that includes California's Imperial Valley and parts of San Diego and Riverside counties. The utility controls about 1,100 MW of generation, including contracted resources, and operates more than 1,800 miles of transmission and 5,000 miles of distribution lines.

CAISO noted that when IID begins participating in the markets, "it will mark the first time all California balancing authorities are participating in ISO-operated electricity markets."

The agreement between IID and CAISO comes shortly after California publicly owned utility Turlock Irrigation District announced it would join EDAM in 2027.

The Imperial Irrigation District

Why This Matters

IID is the latest utility to commit to EDAM, marking another win for CAISO shortly after Turlock Irrigation District announced it would join EDAM in 2027.

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* and *Turlock Irrigation District to Join EDAM in 2027*.)

PowerWatch (formerly BHE Montana), PNM, NV Energy, Idaho Power and Arizona G&T Cooperatives have indicated they're leaning toward EDAM as their preferred day-ahead market choice.

Changed Perspective

IID's decision is significant also because of the district's at-times-contentious relationship with CAISO — and its past opposition to "regionalizing" the ISO.

In July 2015, IID filed an antitrust suit in the U.S. District Court of Southern California contending CAISO had gained monopoly power over the state's transmission services and operations markets.

The suit alleged that — through a series of memos and public statements made between 2011 and 2014 — CAISO had "induced" IID to make $30 million in upgrades to Path 42, one of two transmission lines linking the utility district with the ISO.

CAISO had estimated the improvements would increase IID's maximum import capability (MIC) into the ISO from 462 MW to 1,400 MW, but later downgraded the MIC to the previous level, citing closure of the San Onofre nuclear generating station as the reason for its decision, which IID contested. (See *Federal Judge Upholds*

Imperial Irrigation District Suit Against CAISO.)

The two parties reached a settlement in the suit in 2018 after the ISO approved line upgrades that would allow more renewable energy to flow into the ISO from the utility's service territory.

IID also opposed CAISO's previous efforts to expand into an RTO, initiating a separate *lawsuit* in 2016 seeking to force the grid operator to publicly disclose protected information related to ISO-commissioned studies supporting regionalization.

Speaking at a joint California agency workshop in July 2016, IID's then-General Manager Kevin Kelley said the utility opposed regionalization because it would require the state to relinquish oversight over an entity that suffered costly market manipulation during the 2000/01 Western Energy Crisis.

Kelley at the time said he suspected the "driver" of regionalization was a "for-profit corporation" — namely, PacifiCorp, which was the first utility to commit to joining both the WEIM and EDAM. (See *Governance Plan Critics Urge Slowdown of Western RTO Development*.)

But times have changed, and IID's energy consumption and customer base grow each year, with demand increasing, Robert Schettler, a spokesperson for IID, told *RTO Insider*.

"We're out there making agreements ahead of time as best we can," Schettler said. "But then sometimes the energy that we're expecting isn't available, and we have to go on the market and get it and pay market prices, and then we have to shift those prices to our customers, which has not been popular."

IID hopes that participation in the markets will broaden the utility's reach and bring stability to fluctuating adjustment costs in customers' bills. Additionally, IID has been around for 114 years, and entry into the markets comes as the utility has launched a 15-year plan to upgrade its infrastructure, Schettler noted.

WEIM launched in 2014, and EDAM is slated to go online next spring. IID said in the news release that a "conservative estimate" shows the utility could save $12 million annually once both markets are in use. ■

Growing Clean Energy Sector in Texas May Avoid Damaging Legislation

More Onerous Bills 'Die' as Lawmakers Rush to Finish

By Tom Kleckner

ERCOT breezed through its first heat wave of the season recently using the same valuable resources that helped it survive last year's record-breaking summer: wind, solar and batteries.

The most extreme bills targeting those same renewables appear to have died in the Texas State Legislature.

Thanks to a heat dome settling into position and sending temperatures into triple digits from Dallas to Austin, ERCOT projected demand to threaten its all-time peak of 85.5 GW on May 14. The forecast was off. Demand averaged 77.8 GW during the hour ending at 5 p.m., still a record — for the fourth straight month — for May.

Wind and solar accounted for 47% of the demand during that time, when total available capacity was nearly 108 GW. As was the case last summer, batteries began discharging as the sun set on solar resources. Storage provided less than 1 GW in May 2024. A year later, storage can provide nearly 6 GW of energy.

According to the *Federal Reserve Bank of Dallas*, solar output averaged nearly 17 GW between 11 a.m. and 2 p.m. during the summer of 2024, compared to 12 GW during the same hours in 2023. Between 6 and 9 p.m., storage facilities' discharge averaged 714 MW in 2024 after averaging 238 MW for those hours in 2023.

ERCOT CEO Pablo Vegas has not been shy about praising renewables' contribution to the Texas grid, especially that of solar and batteries.

"We're really continuing to see the benefit of increased resources from the solar and battery perspective," he told reporters during ERCOT's Innovation Summit in early May. "That made a very significant difference last summer. I think that we'll see the benefit of that this summer."

Thomas Gleeson, chair of the Texas Public Utility Commission, agrees. He said in November 2024 that solar and storage "saved" ERCOT during the summer and

Why This Matters

The question in Texas remains: If cheap renewable energy is so important in helping ERCOT meet ever-increasing demand, why are state lawmakers doing all they can to essentially stifle an industry that helps keep prices around the national median?

prevented emergency conditions like those in 2022. (See *ERCOT Continues to Feel the Heat*.)

"Solar and storage are key for reliability in this state. … We need them to be successful," he said during an industry conference.

Texas leads the 49 other states in wind energy and trails only California in *solar and batteries*. The latter two resources dominate ERCOT's interconnection queue.

Yet, lawmakers have stuffed the state legislature's 89th session with bills that would place firming obligations and new interconnection requirements on renewable resources. Other legislation excludes batteries as a dispatchable energy source, contrary to ERCOT's own contention that storage is dispatchable and is valuable in providing ancillary services and energy arbitrage. Still another law would prevent offshore wind power from gaining a foothold in the Gulf of Mexico.

If cheap renewable energy is so important in helping ERCOT meet ever-increasing demand, why are state lawmakers — framed by *The Hill* as a "red-on-red" civil war — doing all they can to essentially stifle an industry that helps keep prices *around the national median*?

"It's often said, 'No one's life, liberty or property are safe when the legislature is in session.' And this time around, it's no different with energy," said Chris Reeder, a partner with Husch Blackwell leading its Texas energy regulatory practice.

"There used to be a time when they just didn't do much on energy," he added during an April webinar. "Those days are past us."

Judd Musser, Texas vice president of the Advanced Power Alliance, told *RTO Insider* that some lawmakers' opposition to renewables stems from a "fear of competition and allegiance to a narrow set" of political allies that benefit from limiting clean energy's growth.

"As technology advances and renewables continue to deliver when the grid is strained, their value becomes increasingly undeniable and opponents find it harder to justify their stances," he said. "What's more troubling is that many of their proposals this session directly contradicted long-held conservative values — private property rights, limited government and free markets — suggesting that clean energy has become such a political flashpoint that this small band of lawmakers are willing to abandon the very principles they typically champion."

Stoic Energy principal Doug Lewin, who has kept close tabs on this year's legislative session, allows that while politics may play a role with the idealogues capturing the headlines, many elected officials have embraced an "all-of-the-above" approach to Texas' power needs.

"I think what we have really seen emerge this session is … kind of pragmatism over ideology, really led by the business community," he said in an interview. "Sure, renewables have some challenges, but we're going to work to integrate them and overcome those challenges. … Otherwise, all of our electric bills are going to go significantly higher without it."

Case in point: Three Senate bills (*SB715*, *SB388* and *SB819*) never made it to the House of Representatives' calendar in time to get a vote before the session ends June 2, effectively killing them.

SB715 would require existing wind and solar facilities in the ERCOT region to back up their energy production with gas generation or be subject to fines. SB388 would update the Texas Utilities Code to reflect the legislature's intent that 50% of generating capacity installed in ERCOT after Jan. 1, 2026, "be sourced from dispatchable generation other than battery energy storage."

Both bills would dampen further investment in clean energy — renewable companies have made plans for $64 billion in new projects in Texas since 2022, mostly for solar and battery storage — and cause existing sites to shut down, industry insiders said. Aurora Energy Research said in a May *report* that about 25 GW of capacity would require contracts for backup generation, leading to a 14% increase in wholesale prices over the next 10 years and cause capacity shortfalls that could result in more than 3 GW of load shed during an extreme weather event.

"If you rely on gas as your sole fuel, your sole source of power, it would be hard to overstate how incredibly stupid that would be," Lewin said. "That just absolutely makes no sense. You absolutely need a diverse set of resources."

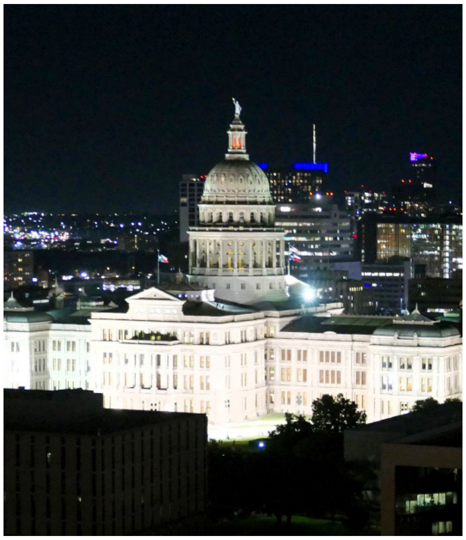
As for SB819, it would have placed some of the most onerous permitting conditions for wind and solar resources. Clean energy advocates called the bill "an industry killer."

"We need policies that support an all-of-the-above approach to meet the expected surge in power demand," said Olivier Beaufils, Aurora's head of USA Central. "Embracing renewables alongside flexible generation sources will help maintain grid stability, lower costs and sustain Texas' economic momentum."

Mark Stover, executive director of the Texas Solar + Storage Association, memorably *said* earlier in the session that he couldn't recall "legislation as damaging to our industry and to the energy market" as SB715 and its companion House bill (*HB3356*).

Stover declined comment about the clean energy sector possibly dodging a bullet, as it did during the 2023 session, until after June 2. (See *Clean Energy Escapes Texas Legislature's Wrath*.)

Perhaps that's because of the danger of "zombie bills" and "frankenbills." Zombie bills refer to legislation that is reintroduced or revived in subsequent sessions after failing to pass in a previous session. Frankenbills are those measures attached to another living bill either through a committee substitute or a final-hour compromise in a conference committee where members meet to resolve their differences.


Texas lawmakers have been burning the midnight oil as the legislative session draws to a close. | © RTO Insider

Lewin said the final days of the session can be an "eternity in legislative time."

"Strange things happen," he said. "There are still some pretty big bills in play. … What we do know is that the worst of the anti-energy bills as standalone bills are dead."

"For two consecutive sessions, cooler heads have prevailed in blocking some of the most extreme anti-energy proposals," Musser said. "Without a competitive, diverse energy mix, Texas risks not only missing out on significant economic development but also struggling to keep the lights on. These legislators recognize renewables for what they are: a vital part of the Texas economy, particularly in rural communities."

The attention now turns to *SB6*. Its low number denoting it as one of the Senate's top priorities, the measure addresses the potential wave of large-load additions. ERCOT has more than 150 GW of new standalone and co-located projects in its large-load queue, adding nearly 20 GW in its most recent month alone.

SB6 requires developers to put down a $100,000 fee for a screening study and to notify ERCOT whether they're considering multiple sites in Texas, giving the grid operator a more accurate read on load growth. It also gives ERCOT and utilities the ability to reject the co-location of data centers with existing generation and hands the grid operator a "kill switch" to shut off large loads if needed.

The measure was preliminarily approved by the House on May 26. It was returned to the Senate with an amendment that allows water utilities to use their rates to fund power infrastructure that can participate in the market and also stripping out *HB3970*, a load-flexibility bill. The two versions must be reconciled.

Several other power-related bills are still in various phases of the legislative process:

- *HB14* would use up to $2 billion in taxpayer money to help build advanced nuclear reactors, provide grants and fund development research. It also would create an office under the governor to "lead the transition to a balanced energy future by advancing innovative nuclear energy generation technologies." The measure has cleared both houses, but the Senate has asked the House to return the bill.
- *HB3556* still is alive in the Senate. The bill was amended to give the Texas Parks & Wildlife Department the ability to review coastal wind projects and removed its ability to stop projects.
- *SB383* has been approved by the Senate and passed out of a House committee, but it did not get a vote by the full membership. It would prohibit offshore wind turbines in the Gulf of Mexico from interconnecting with ERCOT through state waters (extending 9 nautical miles from the coastline), effectively killing Texas *offshore wind*.
- Two bills related to utility ratemaking have passed the House but have not advanced in the Senate. *HB3157* would allow utilities to use interim rate hikes before a proposed increase is approved by the PUC. *HB2868* would require the commission to assume a utility's debt-to-equity ratio is reasonable if calculated using certain metrics as recorded in the books and records for the most recent available financial quarter before the applicable rate proceeding begins. ■

Applications Open for TEF's Non-ERCOT Grant Program

The Texas Public Utility Commission has begun accepting applications for up to $1 billion in grants under one of the four *Texas Energy Fund* programs it administers.

The PUC *said* May 28 that companies with facilities outside the ERCOT region can apply for funding for transmission and distribution infrastructure or generating facilities in the MISO, SPP and WECC portions of Texas. Qualifying projects must address the modernization of infrastructure, weatherization, reliability and resilience improvements, or vegetation management, the commission said.

Applicants must be an existing electric utility, cooperative, municipality or river authority that owns or manages transmission or distribution infrastructure, one or more generators, or a qualifying facility within Texas outside ERCOT. Applicants have to complete and submit an application on the TEF *website* and file a separate submission statement with the PUC (*57830*).

The *Outside ERCOT Grant Program* is one of four TEF offerings, along with the In-ERCOT Generation Loan Program, the Completion Bonus Grant Program and the Texas Backup Power Package Program.

The Texas Public Utility Commission is administering the Texas Energy Fund. | © *RTO Insider*

The Texas Legislature initially allocated $5 billion to the fund, all of which went to the in-ERCOT program. The low-interest loan program, designed to add 10 GW in gas generation, has seen eight projects drop out or be removed in recent months. (See *2 More Projects Fall out of TEF Loan Program*.)

Lawmakers allocated an additional $5 billion to the fund in its 2025 *biennial budget*. An additional $2.2 billion will go to loans and grants for ERCOT gas plants, and $1.8 billion has been dedicated to the backup power package.

The TEF was created by *legislation* in 2023 and approved by voters later that year in a constitutional election. ■

— Tom Kleckner

Suppliers Call for Changes to IESO Local Generation Proposal

By Rich Heidorn Jr.

Electricity cooperatives, independent power producers and biogas generators have asked IESO to reconsider key components of the grid operator's proposed Local Generation Program, calling for longer contract terms and special consideration for some generation types.

Twenty-two organizations *weighed in* with written comments last month on the LGP, which is intended to retain local generation resources whose existing contracts are nearing expiration and provide additional capacity to meet rising demand.

IESO has contracts with about 2,500 facilities with installed capacities between 100 kW and 10 MW. Over the next decade, about 1,600 of the contracts — representing 2,000 of the total 3,300 MW of capacity — will expire. IESO projects Ontario's electricity demand will increase by 75% by 2050 as a result of electrification and industrial and data center growth.

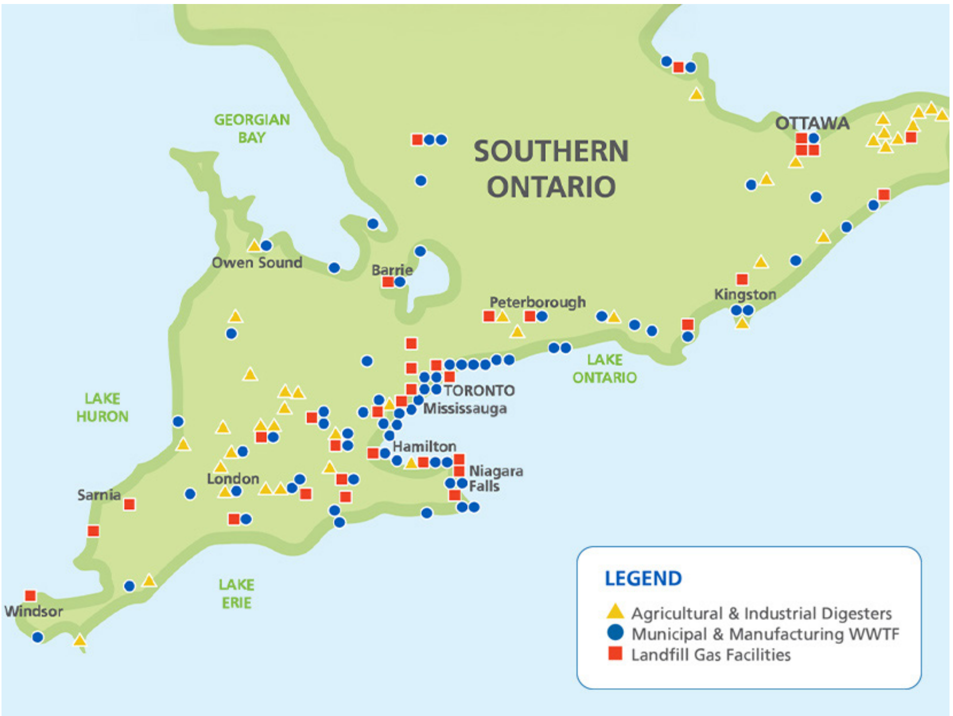
The grid operator says smaller, distribution-connected generation can be built more quickly than large-scale projects and help meet local demand, freeing up transmission capacity.

Generation sources of 100 kW to 10 MW would be eligible to participate in either the re-contracting stream, with proposed five-year contracts, or the new build program, for which IESO is proposing 20-year contracts.

Jonathan Scratch, IESO senior manager of market and system adequacy, said during a *webinar* in April that the grid operator hopes to sign new contracts with "the lowest-cost 80%" of facilities with target quantities reflecting provincial,

What's Next

IESO will hold a webinar to respond to the comments it received on the program, as well as to provide additional details.



Twenty of Ontario's 56 biogas facilities between 100 kW and 10 MW are seeking new contracts as soon as 2030. | *Canadian Biogas Association*

local and regional energy needs. "[To be determined] on whether there would be price caps," he said.

In selecting new projects, the grid operator said it may also weigh policy considerations such as economic participation in the project by an indigenous community and municipal and local distribution company support.

Contract Term

IESO proposed that generators be eligible to seek new contracts if their existing contracts are expiring within five years, making facilities with contracts expiring before 2031 eligible to bid during the 2026 application period.

It proposed five-year terms on renewed contracts, identical to its medium-term procurement program, which it runs every two to three years, as needed.

That is too short for some.

"Where a facility is being re-contracted without any refurbishments, upgrades or expansions, the five-year term length proposed is sufficient," wrote *Community Energy Co-operatives Canada* (CECC). "However, where any refurbishments, upgrades or expansions are undertaken, the term length of five years will not be sufficient to recoup those costs."

The *Canadian Biogas Association* said the re-contracting term should be 15 to 20 years to provide sufficient certainty to invest in maintenance and secure feedstock agreements.

Twenty of Ontario's 56 biogas facilities between 100 kW and 10 MW, totaling 79 MW, are seeking new contracts as soon as 2030. Most facilities are 250 kW to 1 MW, according to the group.

"A short-term contract, paired with frequent participating in competitive procurements, creates too much pricing and uncertainty risk for biogas developers," it said. "Our industry and facility owners (many of whom are small-scale local farmers) will require a longer contract to ensure greater price stability and certainty for a longer term.

"For many facilities, the expiration of current contracts coincides with the end of their engines' useful life. As a result, significant capital investments in upgrades or replacements may be required," it added. "If the program does not provide sufficient value, permanent shutdowns may become necessary for some operators."

The association also said smaller facilities will be at a competitive disadvantage versus larger projects using different technologies that can offer lower prices.

Independent power producer Capstone Infrastructure also *called* for lengthier contracts. It suggested suppliers be granted the flexibility to select a preferred contract length — with up to 30 years for new builds — which it said would produce lower-cost bids through better financing terms. "We are seeing other regions offer longer-term contracts, and this would align with where the industry is heading," it said.

Standard Offer vs. Competitive Bidding

Power cooperatives and clean energy advocates also called for the use of standard offer contracts rather than competitive bidding.

The *Ontario Clean Air Alliance* said it favors competitive bidding for large generation projects. "But the IESO's proposed LGP competitive bidding process for small power projects does not make sense since it will impose onerous costs on participants and create unnecessary uncertainty as to whether their projects will be funded," it said. "Instead of discouraging participation by creating needless red tape, the IESO should establish a fair market value standard offer price(s) for small-scale generation projects. All projects that are willing to accept the fair market value standard offer price(s) should be awarded contracts."

IESO officials said they attempted to make the application less onerous for cooperatives.

"It sounds simple," IESO's Scratch said of the standard offer alternative. "It's inherently not simple to make an assessment of what the right price is. … So, cognizant of that, we've set this up as simplified application process and … the dollar-per-megawatt-hour rate."

Technology Agnostic

IESO's proposal that new build procurements be technology agnostic drew mixed reaction, winning support from the *Ontario Waterpower Association*, which represents the hydropower industry, but opposition from the Canadian Biogas Association.

The biogas group said IESO should conduct technology-specific procurements to acknowledge "the unique operational characteristics, value propositions and cost structures associated with different generation technologies."

"Biogas projects, in particular, provide distinct and system-critical benefits that are often undervalued in competitive procurement processes when assessed alongside technologies with inherently different generation profiles, cost structures and system services (e.g., solar PV or small hydro). These benefits include: firm, dispatchable generation with high reliability; waste-to-energy capabilities that contribute to circular economy goals and emissions reductions; local environmental and economic co-benefits, such as reduced methane emissions from organic waste and support for agricultural and industrial sectors; and baseload or peak-shaving potential, enhancing grid stability and reducing curtailment risks for intermittent renewables.

Biogas is a renewable source of methane gas produced when organic matter breaks down without oxygen. | *Canadian Biogas Association*

Capstone called for "bucketing" generation sources by technology types, to acknowledge those with capabilities such as peaking support, and by region, to reflect higher site costs in urban areas. "This will support reliability where it is often needed most," it said.

The CHP Canadian Advisory Network *said* the projects IESO is seeking to re-contract were originally contracted through a program that was not technology agnostic, "which therefore makes it difficult to re-contract in a technology-agnostic manner."

"For example, [combined heat and power] offers unique value (grid resiliency, improved overall system efficiency, etc.), which may come at a higher price," it said.

It also requested the grid operator add a natural gas price hedging mechanism or "a more equitable sharing of risks, enabling more competitive bidding."

The Ontario Clean Air Alliance countered that fossil fuel generation should be excluded from the program, noting that more than 70% of the gas used in Ontario power generation is imported from the U.S.

IESO's 2025 Annual Planning Outlook predicts fossil gas will generate 25% of the province's electricity in 2030, up from 4% in in 2017. "It doesn't make sense to increase our dependence on American gas when Canada's sovereignty and economy are under attack by President Trump," it said.

LDCs vs. Cooperatives: Transparency, Weighing Local Benefits

Another fault line is the role of LDCs.

CECC *said* the program should "reward meaningful community and indigenous ownership where genuine community equity and governance are embedded (while avoiding LDCs and private developers creating nominal co-ops or token partnerships solely for preferential treatment)."

IESO programs strategist Greg Bonser said the grid operator is "exploring" criteria other than price, "but we haven't decided what those rated criteria might be at this point. For example, we might need to use them for tie breaking."

The Electricity Distributors Association and Ontario Energy Association said LDCs "should lead re-contracting and new contracting."

"The EDA and OEA believe that Ontario's local distribution companies are best positioned to lead both re-contracting of existing distributed generation and the contracting of new DG resources," they wrote. "LDCs have deep visibility into the local value of existing assets within their distribution networks and can engage directly with facility owners on key issues such as refurbishment needs, term lengths and future operational plans."

CECC countered that its members' ability to design new projects are hamstrung because they "mostly do not know if their connection points or local circuits could support an expansion or upgrade."

"The IESO must work with LDCs to publish real-time or forecasted hosting capacity tools and ensure transparent, fair allocation mechanisms when multiple proponents seek access to the same line. Another suggestion is to establish standardized interconnection cost ranges across the province based on project size," it said. "This would give community proponents clearer upfront cost expectations, reduce risk and uncertainty, and enable more predictable financial planning."

Roles for Storage, Rooftop Solar, Virtual Net Metering

IESO also received appeals to expand the LGP program to include storage and smaller facilities such as rooftop solar.

Currently, new rooftop solar generation facilities between 1 kW and 1 MW are eligible for incentives through IESO's electricity Demand-Side Management (eDSM) programs.

Improved technology could result in increased solar production from existing sites. "Given the realized and anticipated

More efficient solar panels mean facilities can increase their output when they renew their contracts with IESO. But critics say the ISO's proposed procurement policy may mean some facilities cannot afford to renew. | *Shutterstock*

increases in the efficiency of solar panels, it is anticipated that we would plan to explore increases in generation capacity at all sites, even where rooftop size or land area constraints exist," Community Energy Development (CED) Cooperative said in its written comments.

But many rooftop solar installations have been in place for nearly two decades, meaning the roofs may need repairs or replacement, adding costs to any re-contracting.

Bonser said the LGP would not offer additional compensation for storage or demand response. "However, if you can cost-effectively integrate those elements into your projects, you may be able to do so," he said.

The Ontario Clean Air Alliance said "all environmentally responsible renewable energy projects," including rooftop solar, should be eligible for the LGP, citing its study that found rooftop solar projects in Toronto could meet 50 to 80% of the city's electricity needs.

CECC said IESO's SaveOnEnergy program does not provide enough financial support for re-contracting solar facilities. It also said community-scale battery energy storage systems (BESS) should be included in the LGP.

"Cooperative ownership ensures that the benefits of storage — including grid services and cost savings — flow back to communities. This scale of storage is well suited for municipal feeders and can play a pivotal role in supporting local energy reliability projects (LERPs) and reducing the need for large-scale infrastructure upgrades, e.g. transmission lines. Bid evaluation should account for both location and time of generation and the advantages of community-scale BESS paired with solar can deliver."

John Kirkwood, president of the Ottawa Renewable Energy Cooperative, said co-ops have had difficulty deploying storage because community-scale batteries are too small for participation in IESO "and LDCs can't contract [with] us."

"Batteries are part of the solution — we all know that — but it's not very easy to add them to the grid," he said.

Kirkwood also urged the grid operator to allow it to aggregate generation from its more than 1,100 members, many of which now have microFIT (feed-in tariff) contracts on individual meters, "which is challenging and costly for the province."

"We're willing to take it into consideration," Bonser responded. "We want to make sure this program is as simple and cost effective as possible for all of the different parties involved, from suppliers such as yourself, who have members, for the LDCs and for the ISO. So, there are a few competing interests."

Kirkwood and other cooperative representatives also called for co-ops to engage in virtual net metering, which would allow members to purchase electricity directly from cooperatively owned projects, even if they are not located on-site.

Allowing cooperative-owned projects to transition into community net-metering structures at the end of the current contract would allow them to continue, said CED Co-op, which has more than 100 FIT and microFIT contracts.

"If there are no reasonable contracting options available upon conclusion of the current contract, we would likely need to decommission the facility," it said. "The current spot market rates do not appear that they would adequately exceed the costs of insurance, LDC fees, lease payments, and operations and maintenance expenses."

Next Steps

IESO expects to report back to the Ministry of Energy and Mines on the LGP this summer and launch the program in 2026.

The grid operator will provide its responses to stakeholders' feedback and present more details about the program designs in a webinar June 5. ■

FERC Approves Implementation Delay for ISO-NE Order 881 Compliance

By Jon Lamson

FERC has accepted a 17-month delay to ISO-NE and the New England transmission owners' implementation of Order 881 and Order 881-A compliance, pushing back the rollout of ambient-adjusted line ratings (AARs) in the region. The RTO and the TOs said the delay is needed to accommodate vendor and software development challenges (*ER22-2357, ER25-410*).

FERC Order 881, issued in December 2021, requires transmission providers to adopt AARs, which provide more accurate real-time temperature information on transmission lines, for near-term transmission requests. The order is intended to free up transmission capacity, as existing static rates are based on worst-case temperature conditions. The order also requires operators to use seasonal line ratings for long-term transmission service. (See *FERC Orders End to Static Transmission Line Ratings*.)

ISO-NE and the TO's compliance with the order was to take effect in July 2025 but has been pushed to December 2026.

"Considering the vendor delay in delivery of the software that is needed for ISO-NE and the [participating transmission owners] to implement Order No. 881, and the time to test and train after delivery of the software, it is highly unlikely that the filing parties will be able to implement the tariff rules as of July 12, 2025," the groups wrote in their request to FERC.

The organizations wrote that ISO-NE plans to complete "all initial integrated software testing by January 2026," which would be followed by trainings, TO testing and procedure development prior to the rollout of AARs in "all required day-ahead and real-time processes."

No protests of the request were filed in the docket. FERC accepted the request in a brief order May 30, writing that "good cause exists to defer the effective dates to implement the requirements of Order Nos. 881 and 881-A in order to provide additional time to complete the development and deployment of necessary software updates." ■

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MISO: New Orleans Area Outages Owed to Scant Gen, Congestion, Heat

Entergy Says Offline Nuclear Generation not a Major Factor

By Amanda Durish Cook

MISO has shed light on the reasons behind the Memorial Day weekend load-shed event in southeast Louisiana, describing a system taxed by early summer heat and rife with congestion and unavailable generation.

Executive Director of Market Operations JT Smith said there were "a number of" planned and unplanned generation outages coupled with higher-than-normal temperatures that paved the way for challenges headed into the weekend.

"We approached some pretty warm days for the season down there," Smith said during a Reliability Subcommittee meeting May 29. He added that evening peaks with "early summer heat" can be a hazardous time.

MISO ordered an approximately three-hour, 600-MW load-shedding event in Greater New Orleans the evening of Sunday, May 25 to avoid bigger reliability issues. (See *MISO Requires Load Shed in New Orleans to Avoid Grid Instability*.)

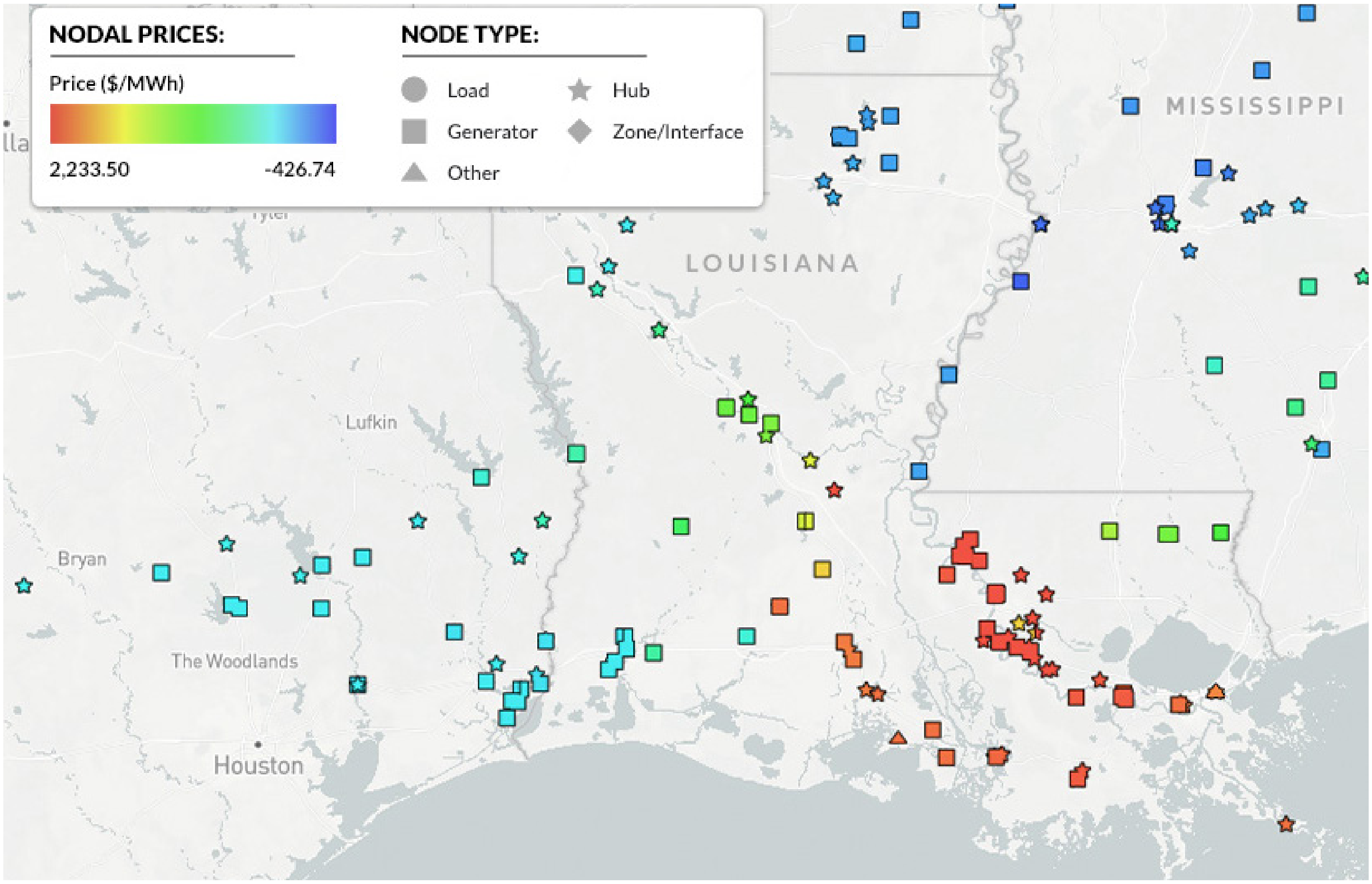
During the first hour of the load-shed event, electricity prices were in the negative — as low as $400/MWh around the Mississippi Delta — while prices in southern Louisiana soared past $2,000/MWh. Electricity appeared undeliverable into the greater New Orleans area because of a lack of transmission.

Smith said MISO operators began noticing congestion problems on Wednesday, May 21. By the weekend, operators were "battling congestion all over the place" in Louisiana, Smith said. He said MISO was keenly aware that it was "important for the transmission system to hold up" with reduced generation and warm weather.

Why This Matters

The rolling blackouts have revived debate around MISO South's lack of regional transmission projects and webwork of load pockets. Another argument says earlier investments in locally available renewable energy and battery storage could have offset the need to shed load.

Generation was available outside Lou-



MISO pricing in southeast Louisiana during the first hour of load shed at 5 p.m. May 25 | *Yes Energy* isiana, "but you could just not get it in" because of the congestion on May 25, Smith said. Smith said MISO's pricing map showed "a lot of red" in southeast Louisiana and "a lot of blue and purple sitting out" north, indicating high prices butting up against negative-cost, trapped generation supply.

Smith said there were a lot of "infrastructure availability" issues May 25. He said operators contended with unusual flow patterns and "import limits not usually seen."

Leading up to the event, MISO was identifying post-contingent positions on transmission lines. Smith said the RTO conducted several on-the-spot analyses to see if any potential congestion problems could rise from localized system operating limit issues to the more serious and widespread interconnection reliability operating limit (IROL) issues.

Smith said that "unfortunately on the 25th," MISO identified a constraint north of Lake Pontchartrain that presented as 125% over its limit.

"It was identified to have cascading potential, putting at least 1,000 MW of load at risk," said Smith, calling it a "very significant" issue that necessitated MISO's call for Entergy and Cleco Power to shed load.

Members of the Louisiana Public Service Commission and the New Orleans City Council have expressed concern over the short notice on the power deficit and have vowed to get answers. Smith said that unfortunately, when an IROL is identified, MISO has precious little time to correct it. Nevertheless, he said the RTO would review its communication protocols and see if it can improve notification time. It will have more information to share at its Board Week meetings in June, he said.

"We'll be looking to improve that posture overall," Smith said. "Since then, it has been a whirlwind of data collection. It's an unfortunate situation, but one that can come up from time to time."

Reliability Subcommittee Chair Ray McCausland, of Ameren, told stakeholders that information is still scarce because the meeting was a mere four days after the event and "there's a lot to discover." From his experience in control rooms, he said he was surprised that MISO wasn't forced to "sacrifice" more megawatts given the situation.

Michigan Public Power Agency's Tom Weeks asked if an earlier order of conservative operations may have helped the situation.

Smith said MISO had very few options in the moment, and a conservative operations declaration would not have returned enough equipment to service to make a difference.

Entergy: Nuclear Gen Offline Days Before Event

Meanwhile, Entergy has challenged Louisiana regulators' narrative that its two offline nuclear plants played a major role in the blackouts.

In a statement to *RTO Insider*, Entergy said its own models did not indicate load-shed conditions, but "MISO uses a different model and has a broader view of system conditions, which MISO is able to see due to its status as the regional transmission coordinator."

"Entergy had been monitoring load conditions due to warmer-than-typical weather, but as noted, its models did not show the need for load shed," Entergy spokesperson Brandon Scardigli said in a statement.

Entergy also said the implication that the nearby, offline River Bend nuclear plant exacerbated circumstances might not stand up to scrutiny.

"While the River Bend generating unit was offline during the event, it had been out for several days before the event, and its outage was accounted for in the generation that Entergy Louisiana and Entergy New Orleans made available to MISO and in MISO's own modeling," Scardigli said.

River Bend reportedly shut down unexpectedly on May 21 because of a leak in its cooling system. The Union of Concerned Scientists released a May 27 *report* in which it singled out River Bend for being one of the most problematic nuclear plants in the U.S. in terms of regulatory violations.

Entergy added that its refueling outage at the nearby Waterford 3 plant was within the norm, as it routinely plans maintenance in the spring and fall. Entergy said the outage was scheduled months in advance.

"The timing of the planned outage was to ensure that this important unit is up and running during the summer months when customer usage is high," Scardigli said.

Episode Spurs Calls for MISO South Tx Planning

The rolling blackouts have already revived debate around MISO South's lack of regional transmission projects and webwork of load pockets.

The Louisiana-based Alliance for Affordable Energy circulated a *one-pager* after the load-shed event that said the longer MISO South waits on transmission planning, "the longer consumers remain vulnerable to load-shed events." It said the RTO needs expanded transmission capacity between its Midwest and South regions to alleviate the South's load pockets.

"Corporations like Entergy have long fought efforts to do this because it could negatively affect their bottom line by forcing them to compete with other electricity producers, and the [Louisiana PSC] and New Orleans City Council have often had their backs in doing so. It's time we put the people of Louisiana and New Orleans first — increasing transmission means we will be better protected from grid failures and will also help to bring down costs," the group wrote.

However, Southern Renewable Energy Association Transmission Director Andy Kowalczyk cast doubt on the notion that more Midwest-South transmission could have helped the load pocket in this situation. He pointed out at the subcommittee meeting that there was plenty of available generation below MISO Midwest that could not reach Louisiana.

The alliance also said earlier investments in locally available renewable energy and battery storage could have offset the need to shed load.

Finally, the organization said the Louisiana PSC and New Orleans City Council should demand information from Entergy and Cleco. It faulted the PSC for dismantling a statewide energy efficiency program weeks before that could have dampened demand. (See *Louisiana PSC Scraps Statewide Energy Efficiency Program*.) The PSC has since reverted to utility-led programs for energy efficiency. ■

FERC Declines MISO Queue Cap Rehearing Requests

By Amanda Durish Cook

FERC is resolute in its support of MISO's annual megawatt cap in its generator interconnection queue.

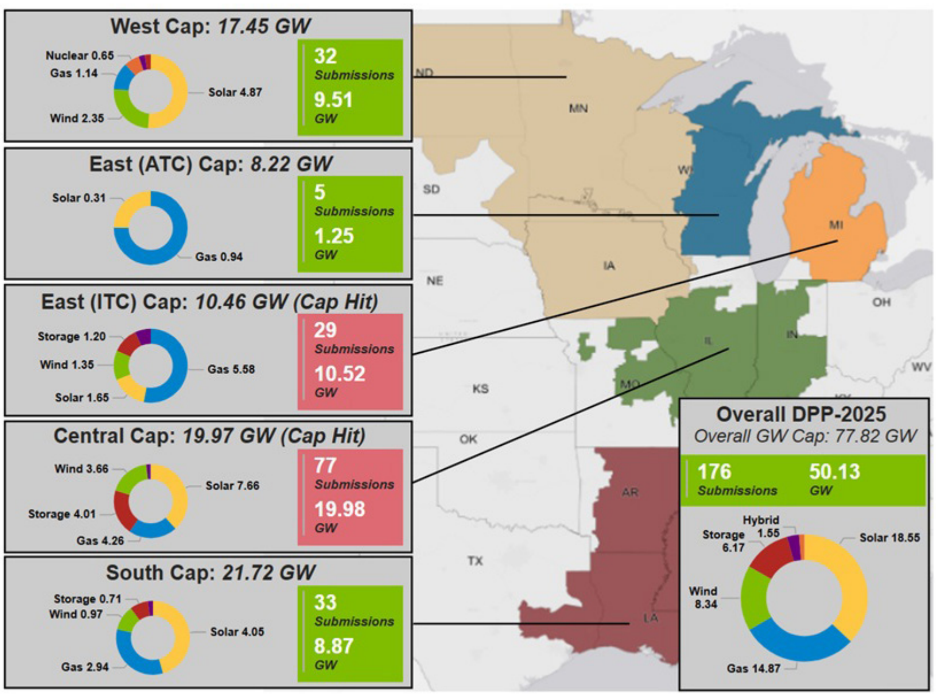
The commission rejected rehearing requests that framed the queue cap as discriminatory, preferential and riding roughshod over state authority (*ER25-507*).

FERC in late January gave MISO the go-ahead to impose an annual megawatt cap on the generation applications it accepts in its interconnection queue. The cap limits megawatt values of queue cycles to 50% of MISO's non-coincident peak among its five study regions. (See *FERC Approves Annual Megawatt Cap for MISO Interconnection Queue*.)

Two study regions — East and Central — already have *exceeded* their megawatt caps for the 2025 cycle. Across all regions, MISO has a 77.82-GW cap for the 2025 cycle. As of mid-May, it has fielded 50.13 GW across 176 submissions.

MISO South regulators in early March asked FERC to reconsider its approval of MISO's queue cap. Led by the Mississippi Public Service Commission, regulators argued the cap needs an exemption for state-designated necessary resources. They asked FERC to backtrack and either reject MISO's plan or condition it on MISO including an exemption for the states, saying the MISO plan tested the very limits of cooperative federalism.

In its May 27 order, FERC decided it didn't transcend its statutory authority and infringe on state jurisdiction by allowing the queue cap, even though the cap will have "incidental effects" on state jurisdiction. It said the Supreme Court already decided those inadvertent encroachments are of no legal consequence. FERC also said that despite Southern regulators' prerogatives, the commission is allowed to consider "resource adequacy concerns in exercising its jurisdiction."



MISO's 2025 interconnection queue cap tracker as of May | *MISO*

Why This Matters

MISO South state regulators and clean energy groups couldn't convince FERC that MISO's new interconnection queue megawatt cap is bad for the footprint.

FERC also said it judged the queue cap plan as fair and reasonable without the state exception and would not order MISO to include one.

Clean energy groups also argued against FERC's acceptance of the cap. They said FERC should reconsider because MISO didn't have a strong rationale for the cap and said the cap itself will introduce undue discrimination and preference among developers vying for a spot on the MISO grid.

FERC disagreed with the groups, who said that in accepting the cap, the commission abandoned standardized generator interconnection processes established under FERC Order 2003. FERC said the clean energy groups should have raised the argument sooner in proceedings but said "in any event," the queue cap followed Order 2003's "recognition of independent entity variations for RTOs/ISOs."

FERC also said it found nothing amiss with MISO's first-come, first served aspect of the cap to determine cutoff points. The commission disagreed with the groups that argued prioritization could create an unfair environment by incentivizing projects to line up for exploratory or speculative positions. Instead, MISO ultimately would study submitted interconnection requests as part of a cluster. FERC said projects that entered too late to beat the cap simply would be subjected to a later cluster of projects. ■

National/Federal news from our other channels

Uranium Mine Expansion Approved in Just 11 Days

NetZero Insider

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

FERC OKs MISO Generation Replacements Connecting at Different Points than Predecessors

By Amanda Durish Cook

FERC has approved MISO's new generation replacement provision that allows replacements to reconnect at more preferred points on the grid over clean energy groups' concern that it plays favorites.

The commission said replacement generation in MISO should be able to link up at different points of interconnection (*ER25-1802*). MISO proposed that it would allow the interconnection point substitutions when they're "electrically equivalent to the original point of interconnection" and when they don't cause material adverse impact to MISO's transmission system.

Clean energy groups, including American Clean Power Association, the Solar Energy Industries Association, Advanced Energy United and Clean Grid Alliance, had argued MISO's proposal should be rejected because it's unfair to other planned generating facilities. The groups said the plan would discriminate between similarly situated projects.

However, a group of utilities, including Alliant, Lansing Board of Water and Light, Consumers Energy, DTE, ITC, Michigan Public Power Agency, MidAmerican Energy, Muscatine Power and Water, Wolverine Power Supply Cooperative and WPPI Energy, said the proposal would allow replacement generation to connect at more favorable interconnection points that have similar impacts on the grid.

FERC decided the plan would allow "more cost-effective and timely replacement of existing generating facilities, which will help address regional resource adequacy needs and allow interconnection customers to avoid investing in redundant infrastructure." The commission further said the replacement facilities would dodge duplicative contracts, deeds and site control costs that might come with both a new site for a replacement facility and "a path to connect that site to the original point of interconnection."

The commission said it agreed with the Organization of MISO States that MISO's plan would remain in keeping with the RTO's current methods for discovering and minimizing adverse impacts on the transmission system. FERC said it would pair "offering increased flexibility to interconnect new generation resources in a more efficient manner" with "supporting state resource planning and ratepayer affordability."

FERC said the new prerequisites MISO placed on moving an interconnection point in addition to its usual replacement study process — interconnecting at the same voltage level, not introducing new constraints and not forcing a distribution factor change of more than 5% — "will ensure that an alternate point of interconnection is electrically equivalent to the existing point of interconnection."

The commission disagreed with arguments that by allowing replacement facilities to move their points of interconnection, MISO was creating a process that more closely resembled a new interconnection request with the added bonus of skipping the queue.

"We do not believe that providing this limited flexibility to replacement generating facilities to interconnect at a different, but electrically equivalent, point of interconnection results in an unduly discriminatory interconnection process," FERC wrote in the May 27 order.

FERC said MISO's commitment to preventing a replacement generator from adversely affecting the grid should take care of clean energy groups' concern that permission to move a point of interconnection would drive up network upgrade costs by replacements claiming spots on the grid that other interconnection customers had "reasonably expected" to use.

MISO has said its generator replacement process has been instrumental in limiting the impacts of power plant retirements. Since it began the process in 2019, MISO said it has accepted about 5.9 GW in replacement requests and is studying 4.9 GW of replacement requests.

The RTO expects 25 GW of coal retirements through 2030, up 5% from its 2024 forecast. In the same time frame, MISO's membership plans to add about 10 GW of solar generation and significantly more gas generation. ■

| © RTO Insider

MISO to Make Transmission Re-evaluation Process More Public

By Amanda Durish Cook

MISO said it will create more public notices throughout its variance analysis, the process it uses to reassess transmission projects that experience cost increases or other obstacles to construction.

However, industrial customers are still asking the RTO to enact stronger cost-containment boundaries on transmission projects. (See *End Users Push MISO for More Intensive Cost Overrun Evals on Tx Projects*.)

Jeremiah Doner, MISO director of cost allocation and competitive transmission, said the variance analysis remains an efficient avenue for the RTO to track spending, permitting and progress on pricier or stalled projects.

"We haven't identified an issue that we think needs to materially change the process today," Doner said during a May 27 meeting of the Regional Expansion Criteria and Benefits Working Group. He added that he understands why stakeholders would call for added cost controls given the "significant investment" members have made in transmission in recent years.

However, Doner said MISO could alert stakeholders more clearly when it has found grounds for a variance analysis, update them as it studies projects and better communicate resolutions.

Why This Matters

MISO said it will make more public announcements and updates around its variance analysis, the study it uses to re-evaluate transmission plans that incur cost overruns or other impediments.
The RTO is not, however, entertaining an ask from industrial customers to lower the 25% overage minimum before it inspects projects.

| Northern Indiana Public Service Co.

The RTO has not "sent out a widespread communication" when a project enters a variance analysis, Doner said, but moving forward, it will send mass emails to stakeholders and dispatch a representative to make announcements before the Planning Advisory Committee. When the study concludes, MISO will explain the outcomes to the committee.

MISO previously only made postings on its website to publicize variance analysis steps.

The new process will be reflected in MISO's Business Practices Manuals, Doner said. While MISO wants to report as much as possible on its variance analyses, the RTO is limited by confidentiality provisions between it and transmission developers. Doner called variance analyses "very situation-specific."

The Union of Concerned Scientists' Sam Gomberg asked if MISO had ever deemed a transmission project's cost increases unreasonable.

"Thankfully, our sample size for that question is extremely small," Doner said. MISO has only encountered three instances of a 25% or more cost increase on transmission projects, he said: The RTO found the cost increase was prudent on one; worked on a mitigation plan for another to ensure costs did not further increase; and has yet to make a determination on the last project.

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

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

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

MISO has completed nine variance analyses to date. For most studied projects, the RTO has either drawn up mitigation plans or let projects stand. While the grid operator has never reassigned a project developer through the analysis, it has canceled one 500-kV project in MISO South because of a right-of-first-refusal law in Texas. (See *FERC Rejects Last-ditch Effort to Save Tx Project*.)

McNees Wallace & Nurick attorney Ken Stark, representing MISO's End-Use Customer sector, said he is still looking for a more restrictive cost increase threshold than 25%. Stark said MISO could consider a 15 or 20% threshold on cost overruns to trigger the analysis, instead of his originally suggested 10%.

Stark also continued to advocate for an independent third party to evaluate cost overruns or annual informational reporting to FERC on transmission projects that go over budget. Stark dropped a previous recommendation that the Organization of MISO States or the Independent Market Monitor take an active role in evaluating project costs. Multiple stakeholders said those two entities are ill-suited for reviewing transmission: OMS because it represents state regulators that ultimately approve routes and certifications of public convenience and necessity, and the IMM because its purview is markets, not transmission.

MISO transmission owners at the meeting said there did not appear to be a need to install more restrictive thresholds or further checks and balances. They maintained that the status quo variance analysis properly evaluates changes in projects.

Duke Energy's Jay Rasmussen said the variance analysis remains appropriate and that MISO, as an independent entity, is up to the task of reviewing projects. He said more frequent updates from the RTO on the analyses should put more stakeholder attention on transmission costs.

"We think MISO's approach is a good one at this point and see no need to tinker with it," Ameren's Justin Stewart agreed. ■

MISO Going for 2nd Attempt to Fast-track Power Plants in Queue

RTO to Limit Process to 50 Applicants

By Amanda Durish Cook

MISO confirmed it will make a second bid to FERC to establish a temporary fast lane in its interconnection queue, this time limiting the process to 50 generation projects.

The new, 50-project limit would reduce the number of quarterly cycles MISO ultimately accepts in the expedited process. MISO also would limit the number of projects it studies per quarter to no more than 10.

FERC in mid-May turned down MISO's proposed express lane, saying MISO failed to establish standards on which projects may enter based on resource adequacy needs and failed to control how many projects could line up for expedited treatment. (See *FERC Rejects MISO's Interconnection Queue Fast Lane*.)

Previously, MISO planned to open up to 14 quarterly submission windows to an unlimited number of projects through the end of 2028.

"FERC gave us good guidance on what is necessary to refile," Director of Resource Utilization Andy Witmeier said at a May 28 Planning Advisory Committee meeting when announcing the intention to refile.

MISO plans to submit a fresh proposal to FERC by June 6, which would request an Aug. 5 effective date. The RTO is forgoing a usual stakeholder comment period on edits to the refile.

Why This Matters

MISO may set a personal best for the fastest FERC refile of a proposal if it can resubmit its interconnection queue fast lane proposal — with a new, 50-project limit and resource adequacy requirements — to FERC within three weeks of the commission's initial rejection.

Cooperative Energy's natural gas-fired R.D. Morrow Sr. Generating Station in Mississippi | *Cooperative Energy*

Witmeier said the 50-project limit is based on PJM's Reliability Resource Initiative and said FERC appeared to be "comfortable" with that figure. He also said MISO has been coordinating with the Organization of MISO States (OMS) and individual state regulators to put finishing touches on the filing.

MISO now would require that projects and their correlated resource adequacy needs be within the same local resource zone. Developers must submit the specific load addition or capacity shortage their project would address, with MISO publicly posting those associations.

The RTO also is stipulating that the interconnection service of the projects should not exceed 150% of an identified megawatt need.

Regulators now must "verify instead of notify" MISO as to how projects will meet a resource adequacy need, Witmeier said.

He said the new project maximum and regulator verification will eliminate the open-ended number of projects and better describe how projects will meet anticipated generating shortfalls.

"There are no real changes to the process. These are just guardrails and gaming requirements," Witmeier told stakeholders.

Witmeier said the expedited process should wrap up sooner than it would have under MISO's first proposal.

"It's possible that we're done by 2027 or late 2026. … I suspect we'll have our 50 projects by the time 2027 comes into play," Witmeier said. "We're proving that this is not a new queue and will address immediate needs."

Because of FERC's initial rejection, MISO would accept project applications under a second try through Aug. 11 and kick off its expedited studies for the first cycle Sept. 1 instead of the originally planned late May.

Wisconsin Public Service Commissioner Marcus Hawkins contradicted MISO's characterization that OMS is working in close collaboration with it on the revised filing. Hawkins said aside from previewing a MISO draft of the regulator verification of projects, "most of the proposal we're seeing for the first time."

"OMS really can't work in a 14-day time period. That's just not how we work. … It's not possible to have OMS coordination on this new filing," Hawkins said. He explained that decision-making in OMS involves multiple check-ins and bringing several parties up to speed on issues.

Witmeier said he understood the OMS board setup and agreed that scheduling obstacles would preclude the organization from full participation before the refiling target date.

Stakeholders said they worried that disparities among states' methods for substantiating resource adequacy needs would result in expedited projects spread unevenly throughout the footprint.

Witmeier said it was possible a state would never justify a project for the fast lane while other states would recommend multiple facilities. He repeated several times in his presentation that MISO is not a resource planner.

Clean Grid Alliance's David Sapper said he's concerned about the 150% threshold beyond stated needs. He said such a large margin would be anti-competitive and discriminatory and could introduce network problems.

"It's that margin that's not balanced that could change import and export limits in ways that are not good for reliability," Sapper said. He also said MISO's in-zone requirement would unfairly elbow out suppliers from other zones.

"That's a biggie. We need to think about this need determination," Sapper said.

Sustainable FERC Project's Natalie McIntire questioned why MISO would use interconnection service instead of a megawatt value to set the 150% threshold.

Other stakeholders said they didn't see how the proposal wouldn't again exclude Illinois' and Michigan's retail choice areas, where competitive markets, not vertically integrated utilities, ensure resource adequacy. MISO would open the fast lane to interconnection customers with power purchase or other agreements in addition to load-serving entities with self-supply acknowledgments and projects in the existing queue wishing to transfer to the express lane.

Finally, stakeholders asked if MISO would consider exceptions beyond the 50 projects.

"We certainly believe that this will meet our current needs and meet FERC's requirements. Beyond that, we don't see a need for extension," Witmeier said.

It's unclear if MISO's project cutoff and documented resource adequacy requirements will be enough to quell clean energy groups' discrimination complaints about the first proposal. The Natural Resources Defense Council, Sierra Club, Sustainable FERC Project and Union of Concerned Scientists were among the groups challenging the design the first time around.

Following FERC's rejection, the Sierra Club said MISO's "discriminatory plan" would have favored gas plants at the expense of the approximately 200 GW of wind and solar generation and battery storage currently in the MISO interconnection queue.

"It's good to see FERC taking a deep look at extreme proposals like MISO's here. Interconnection fast-track proposals … are fundamentally discriminatory, and the commission made clear that discriminatory tools should only be used to address the most severe emergencies. MISO failed to demonstrate such an emergency here, and its policy was not well tailored to meet one," Sierra Club Senior Attorney Greg Wannier said in a statement.

Wannier said Sierra Club planned to engage in MISO's stakeholder process to "address the serious concerns raised by commissioners and stakeholders and come back with a targeted solution." ■

Palisades Nuclear Restart Clears Environmental Review

NRC Finds No Significant Impact from Unprecedented Plan

By John Cropley

The Nuclear Regulatory Commission has determined there would be no significant environmental impact from restarting the Palisades Nuclear Plant in Michigan.

The NRC decision issued May 30 reaches the same conclusion as its draft decision Jan. 31.

Formerly operated by Entergy, the 800-MW facility in Covert Township went offline in May 2022 in preparation for decommissioning, but barely a year later, new owner Holtec International began to float the idea of bringing it back into service.

No commercial reactor in the U.S. has been restarted in such a scenario, although Constellation Energy is working toward that goal with the former Three Mile Island Unit 1, which shut down in 2019, and NextEra Energy has filed notice with the NRC about potentially restarting the Duane Arnold Energy Center, which ceased operations in 2020.

The NRC issued the environmental assessment of the Palisades proposal in cooperation with the U.S. Department of Energy's Loan Programs Office, which in September 2024 extended a $1.52 billion loan guarantee to Holtec to help financed the effort.

More recently, *DOE approved disbursement* of $56.8 million for that purpose — a relatively small sum, but notable amid the wholesale slashing under way at the time as the new Trump administration took aim at the clean energy priorities of the Biden administration.

While the two presidents have little common ground on wind and solar generation, both supported nuclear power. (See *Trump Orders Nuclear Regulatory Acceleration, Streamlining*.)

In the determination issued May 30, NRC said restarting Palisades would provide baseload power to meet current system needs. Holtec also noted it would help Michigan reach its targets of at least 80% clean energy by 2035 and 100% by 2040.

NRC said it considered 11 potential direct or indirect environmental impacts from a restart and determined none would be significant. It also determined there are no environmentally preferable alternatives to restarting Palisades.

Why This Matters

The Michigan facility is one step closer to becoming the first retired U.S. nuclear plant to restart.

In an April update, Holtec said the project remains on schedule and on budget. As it refurbishes the physical plant, it is rebuilding its workforce: Staffing has rebounded from a low of 220 to 570; 26 plant operators have requalified; and the first initial operator class was on track to complete their license exams this month.

Also, FERC approved Holtec's waiver request to maintain the grid interconnection, which was suspended after the plant shut down and otherwise would have been sunsetted. ■

The U.S. Nuclear Regulatory Commission has determined that restarting the Palisades Nuclear Plant would have no significant impact on the environment. | *Holtec International*

DC Circuit Affirms Rejection of N.Y. Transmission Owners' Request for Self-funding

Decision Upholds FERC Finding that Risks are Not Costs

By Michael Brooks

The D.C. Circuit Court of Appeals on May 27 denied a petition by New York Transmission Owners seeking to overturn a FERC decision rejecting their request to be able to self-fund network upgrades (*21-1256*).

A three-judge panel of the court found that FERC "adequately" and "reasonably" explained its rationale for rejecting the TOs' complaints in 2021 and affirming that decision in 2022 (EL21-66, ER21-1647). (See *FERC Upholds Denial of NYTOs' Cost Allocation Complaint*.)

The TOs had filed two complaints simultaneously under Federal Power Act sections 205 and 206 seeking to change the NYISO tariff to allow them to fund network upgrades on their lines. They argued that the ISO's current rules, which give generators the right to fund the upgrades needed to interconnect to the grid, impose risks on them for which they are uncompensated.

Key to FERC's rejection of the TOs' arguments in their Section 205 complaint was that risks themselves are not costs, which they could be entitled to recover under the FPA and the NYISO-TO Agreement. The TOs already recover the costs associated with maintaining and operating the upgrades; the costs of managing and mitigating risks are not "reasonably incurred costs" as defined by the agreement, FERC ruled.

The court reiterated much of FERC's reasoning in its order.

The TOs "did not aim to recover 'reasonably incurred costs,'" it wrote. "They do not identify any expense they have actually incurred that is uncompensated.

| NYPA

Why This Matters

The ruling is potentially a blow to the prospect of TO self-funding in other RTOs, which are currently under scrutiny by FERC.

Instead, the owners argue that the rules governing upgrade funding should be changed to compensate them for 'risks' associated with owning and operating the upgrades. That framing illuminates the owners' true goal: They hope not to recoup costs already 'incurred,' but to anticipatorily recover potential costs that have not yet materialized."

The court also rejected the TOs' "rebrand" of their risks in their judicial appeal as the cost of capital, which they argued should be treated as recoverable. But "the cost of capital is not an expense that the owners shoulder by virtue of operating the transmission grid," it wrote. "Neither 'risks,' nor the 'cost of capital' that reflects those risks, are relevant to identifying a utility's incurred costs."

In examining the TOs' Section 206 complaint, the court found they were "no more successful in challenging FERC's dismissal." It said they had not demonstrated that the NYISO tariff was unjust and unreasonable, and that "the commission fully and reasonably addressed" their arguments.

"FERC consistently explained that its ratemaking approach includes an 'enterprise-wide' risk calculation that compensates the owners for any such risks they face," it wrote.

The commission is currently examining TO self-funding in other RTOs. It issued an Order to Show Cause in 2024 to MISO, PJM, SPP and ISO-NE, telling them explain how the practice is just and reasonable, as it potentially favors TOs over interconnection customers (EL24-80). (See *FERC Issues Show-cause Order on TO Self-funding in 4 RTOs*.) ■

MMU, FTI Argue for Maintaining Uniform Pricing in NYISO Capacity Market

By Vincent Gabrielle

NYISO and its stakeholders continue to consider different designs as part of their Capacity Market Structure Review, but one idea should be dismissed, according to the Market Monitoring Unit and FTI Consulting: bifurcated pricing.

Though all RTOs with capacity markets may be concerned with their effectiveness in maintaining resource adequacy, NYISO is perhaps more unique in that, according to the MMU, new investment in generation is primarily driven by New York state procurements. In a market based on the net cost of new entry, stakeholders are concerned that this could lead to keeping older, more inefficient resources longer than necessary and at a higher cost to consumers. (See *NYISO Stakeholders Debate Purpose of Capacity Market*.)

A bifurcated — or "discriminatory" — market would have two separate demand prices: one for existing resources and one for new entries to the market. According to NYISO consultant FTI, such markets can result in short-term reductions in costs to consumers, but "in the longer run, as more existing capacity inefficiently exits as a result of the artificially low capacity price and is replaced with high-cost new capacity, the short-run consumer savings will tend to turn into higher costs for future consumers."

"From a social welfare standpoint, all of this is inefficient," FTI's Scott Harvey said in the middle of his *presentation* to the Installed Capacity Market Working Group on May 22. "It's going to reduce social welfare because unless we do the price discrimination perfectly, we're going to shut down some existing capacity that's got lower cost than new capacity, and that reduces social welfare."

Biasing the market toward new capacity also incentivizes the construction of short-lived assets because they will make less money as they age, even if they are initially higher cost, he said.

Balancing the market such that it retains enough units to meet reliability needs while incentivizing new entry and economic exit is tricky, Harvey acknowledged, especially amid low reserve margins.

FTI offered several approaches to a bifurcated market: holding a two-stage auction with separate supply curves but a single demand curve, with a lower price cap for existing capacity; a single-stage auction with a single supply curve but separate demand curves; and a two-stage auction with both supply and demand curves completely separated. Each construct, however, had its own drawbacks under certain circumstances, according to FTI's presentation.

"If you are close to the edge already on reliability, then shutting down existing capacity will have a larger impact," Harvey said. "Anything that drives up the cost of new capacity and less [generation] comes in than you expected is going to have an impact. If some of the existing capacity is already shut down by the time you realize the new capacity isn't going to show up, you're going to have problems."

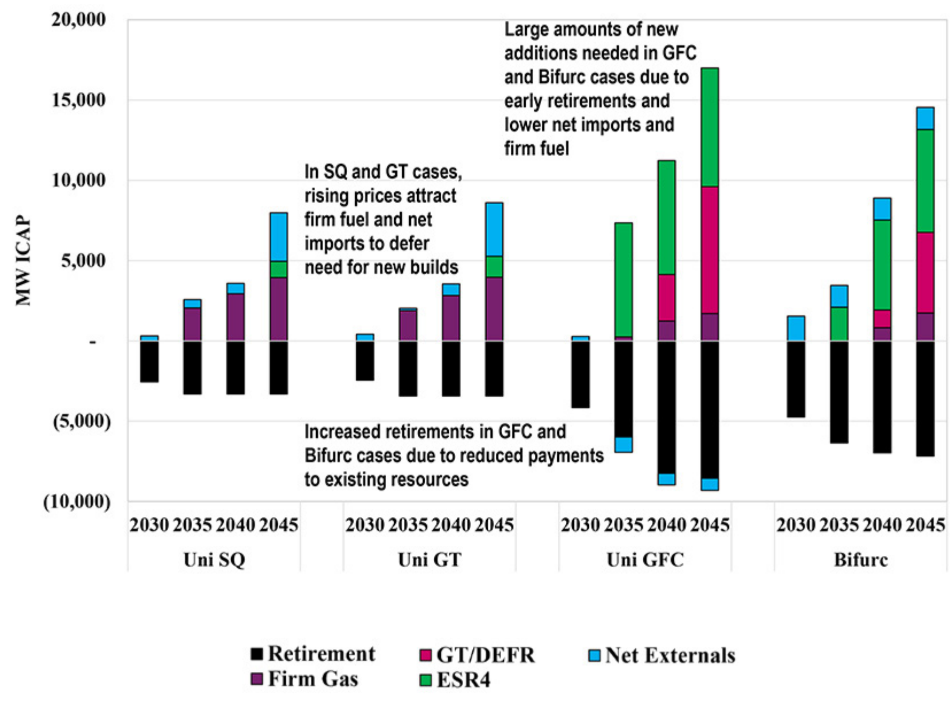
FTI noted that the natural gas market was bifurcated by the Natural Gas Policy Act of 1978, but this ultimately resulted in inflated, high prices, and by 1989, the law was repealed.

Potomac Economics' Joe Coscia *presented* the MMU's quantitative model using multiple scenarios showing that price discrimination between new and old units would lead to both "inefficient behavior" and higher investment costs.

Capacity prices also rise relative to status quo, and capacity surpluses decrease.

"That's a result of the early retirement of existing resources or inability to attract imports and firm gas instead of replacing it with more expensive new capacity," Coscia said.

He said the MMU's results pointed toward the advantages of uniform clearing prices based on cost of new entry, even when there isn't much investment in the peaking technology. ■



The statewide economic and reliability supply changes under several different scenarios that the MMU analyzed | *Potomac Economics*

DOE Orders PJM and Constellation to Keep 760-MW Eddystone Generators Online

By Devin Leith-Yessian

The U.S. Department of Energy has issued an emergency *order* to keep Constellation Energy's Eddystone Units 3 and 4, located outside Philadelphia, online under Section 202(c) of the Federal Power Act. The order directs Constellation and PJM to keep the units available for dispatch through Aug. 28.

The order states that retaining the two gas-fired generators, with a combined output of 760 MW, is necessary to prevent emergency conditions in PJM "due to a shortage of facilities for the generation of electric energy, resource adequacy concerns and other causes."

"Maintaining access to affordable, reliable and secure power is always our top priority, particularly during the summer months when electricity demand reaches its peak," Energy Secretary Chris Wright said in a May 31 *announcement* of the order. The generators were scheduled to be retired that day.

The order cited PJM CEO Manu Asthana's March congressional testimony that reliability is challenged by a combination of government policies prompting generation deactivations, data center load growth and an interconnection queue composed mostly of non-dispatchable generation. It also pointed to PJM's February 2023 "Energy Transition in PJM: Resource Retirements, Replacements & Risks" position paper, which found the RTO could face a capacity shortfall in 2030. (See *PJM Whitepaper to Highlight Future RA Concerns*.)

PJM voiced its support for the emergency order in a May 31 *statement*, in which it calls the order a "prudent, time-limited step" that will allow the department, RTO and Constellation to further analyze whether there is a long-term need to retain the Eddystone generators.

"For over two years, PJM has repeatedly documented and voiced its concerns over the growing risk of a supply-and-demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers," PJM said.

In its 2025 Summer Outlook, PJM stated it could fall short of peak loads under an "extreme planning scenario," requiring the deployment of demand response and increased risk of emergency procedures. The extreme scenario looks at maintaining PJM's reserve requirement under a 90/10 peak load, which is set at 166.6 GW for summer 2025, whereas the Operations Assessment Task Force's report focuses on the ability to reliably serve the 50/50 forecast peak of 161 GW. The latter report did not identify any reliability violations in the summer. (See "Summer Outlook Finds Possible Reserve Shortage," *PJM OC Briefs: May 8, 2025*.)

Why This Matters

The emergency order to keep the gas-fired Eddystone Units 3 and 4 online is the second to follow an executive order widening the circumstances under which fossil-fueled generators can be required to remain in operation past their desired retirements.

Eddystone Generating Station in Eddystone, Pa. | *Constellation Energy*

Constellation *requested* PJM authorization to bring Eddystone offline on Dec. 1, 2023, on the grounds that "continued operation of these units is expected to be uneconomic." PJM *responded* a year later that it found no transmission reliability violations associated with the deactivation, clearing Constellation to retire the units on May 31, 2025.

"Constellation is pleased to work with the Department of Energy and PJM and is taking emergency measures to meet the need for power at this critical time when America must win the AI race," the company said in an emailed statement. "Constellation is taking immediate steps to continue to operate Eddystone Units 3 and 4 throughout the summer."

PJM spokesperson Jeff Shields told *RTO Insider* that PJM does not hold the authority to require generation owners to continue operating when needed for resource adequacy.

"We can only request reliability-must-run to provide us enough time to build transmission to address system issues that will be created by the removal of the resource from the grid. It is not meant for resource adequacy; we can't ask an owner to continue to run based on current supply/demand challenges," he said.

The order directs PJM to submit the steps it's taking to ensure Eddystone remains available by June 15, as well as to provide information as requested about the environmental impact of the order. Both the RTO and Constellation also are directed to file with FERC any necessary tariff revisions or waivers.

When Section 202(c) emergency orders may conflict with environmental standards, generation run hours should be limited to hours needed to resolve the emergency; the order limits dispatch to "the times and within the parameters determined by PJM for reliability purposes."

"To minimize adverse environmental impacts, this order limits operation of dispatched units through the expiration of the order. PJM shall provide a daily notification to the department reporting whether the Eddystone units have operated in compliance with the allowances contained in this order," it continues.

The order states the department will continue to evaluate whether Eddystone is needed for reliability under an April 8 executive *order* that widens how the Section 202(c) authority may be used. (See *Trump Seeks to Keep Coal Plants Open, Attacks State Climate Policies*.)

DOE is developing a methodology "to identify current and anticipated reserve margins for all regions of the bulk power system" regulated by FERC. The executive order "requires this methodology to be published by July 7, 2025, and be used to establish a protocol to identify which generation resources within a region are critical to system reliability and prevent identified generation resources from leaving the bulk power system."

Earlier in May, DOE issued another emergency order to keep Consumers Energy's 1,560-MW J.H. Campbell coal plant in West Olive, Mich., operational beyond its May 31 retirement. The company entered into an agreement with the Michigan Public Service Commission to stop burning coal by the end of 2025. (See *DOE Orders Michigan Coal Plant to Reverse Retirement*.)

Environmental Organizations Object to Emergency Order

The Natural Resources Defense Council *wrote* that the orders in PJM and MISO are part of a larger effort to promote fossil fuel generation at the expense of impacts to health and consumer rates.

"The Department of Energy's move to keep these zombie plants online will have significant public health impacts and increase electricity costs for people in Michigan and Pennsylvania," said Kit Kennedy, power sector managing director at NRDC. "These orders are about a power grab, not a power emergency. These dirty and expensive fossil plants were slated to close because they could not compete with cheaper, cleaner alternatives." ■

PJM Files Waiver Seeking Additional Time to Select Board Candidates

By Devin Leith-Yessian

Why This Matters

A vote ousting two PJM Board of Managers members in May left the RTO with one month to find and vote on alternative candidates, leading the RTO to seek an extension from FERC.

PJM has asked FERC to grant it more time to find candidates to fill the two Board of Managers positions vacated when the Members Committee voted against re-electing two incumbents May 12. (See *PJM Stakeholders Reaffirm Board Election Results*.)

The May 30 *filing* states that the RTO's Nominating Committee (NC) needs more than the one-month period permitted by its Operating Agreement to select new candidates after the MC fails to elect a full board. It seeks instead to impose a Sept. 25 deadline for the NC to nominate new candidates. The committee is composed of one member from each of the five member sectors and three from the Board of Managers.

"While the Nominating Committee has already been reconvened and met, this waiver request is necessary to ensure sufficient time to identify potential board members and to complete appropriate due diligence, including background checks, prior to announcing the proposed nominees to be considered and voted on by the Members Committee," the filing states.

The MC voted against re-electing then-Chair Mark Takahashi and board member Terry Blackwell during PJM's Annual Meeting on May 12. When stakeholders sought to reconsider the vote the following day, Takahashi removed his name from the running; a subsequent motion to reconsider Blackwell's election failed. (See *PJM Stakeholders Vote Out 2 Board Members*.)

PJM wrote that the current board meets OA requirements for the "size, the expertise and experience, and the composition of the board" and can continue operations until the membership votes on new members.

Mark Takahashi, PJM Board of Managers | © *RTO Insider*

PJM Board of Managers member David Mills speaks during the May 14 Public Interest and Environmental Organization User Group meeting. | © *RTO Insider*

In a May 29 notification, PJM announced the NC had decided to continue working with Korn Ferry International in the search for the two new candidates. The firm was brought on to aid in finding candidates to replace outgoing board member Dean Oskvig, who retired and was replaced by Matthew "Matt" Nelson, principal of regulatory strategy at Apex Analytics in May.

Those interested in applying can submit resumes to Korn Ferry at *PJMBoard@Korn-Kerry.com*. The announcement states the firm will not reach out to state commission members or government employees without their consent "to avoid the appearance of impropriety." Officers and employees of PJM members or their affiliates are prohibited from serving on the board, as are those with financial interests in PJM members. Prospective candidates are encouraged to submit applications by June 30.

"The Nominating Committee seeks to consider a broad and diverse field of candidates who possess the appropriate expertise and experience to oversee PJM as it fulfills its public service responsibilities in a complex and changing industry and regulatory environment," PJM said in the notification. ■

N.J. BPU Backs New Grid Modernization Rules

Agency Seeks to Make Connection Easier for Solar, Storage

By Hugh R. Morley

Facing a dramatic electricity rate hike driven in part by a shortage of generation sources, the New Jersey Board of Public Utilities has approved new grid modernization rules that the agency says will make the process of launching new distributed sources easier and faster.

The board voted 4-0 on May 21 for rule changes the agency said will streamline the process by which distribution grid interconnection applications are handled. Among the changes are the enactment of more frequent updates to hosting capacity maps and a revised dispute resolution process, according to *a statement* from the board.

The new rules also include a "pre-application and verification process to provide applicants with an early indication of project feasibility and costs, and a requirement for utilities to have a web portal for a more consistent interconnection application process regardless of service territory," the board said.

The approval came as state ratepayers on June 1 will see a 20% increase in the average electricity bill, which has stoked anger among lawmakers, ratepayer advocates and BPU officials. The increase, based on the prices in the state Basic Generation Service auction held in February, was affected by the dramatic price rise in the PJM capacity auction held in July 2024.

PJM officials say the increase stems in part from old fossil fuel power sources shutting down at a faster pace than new generation sources, mainly clean energy, are coming online. Both New Jersey and PJM forecast a major increase in electricity demand due to the proliferation of data centers, greater electric vehicle use, building electrification and other factors.

Convergent Energy and Power

Why This Matters

BPU says the rules will make it easier to get solar and storage facilities online, which the agency said in a statement are "some of the cheapest and fastest resources to come online.'

Controlling Energy Costs

While the BPU has planned its grid modernization process for three years, the release comes as the agency looks for ways to get new sources online more quickly. (See *NJ Regulators Seek 'Proactive' Grid Upgrade Plans from Utilities* and *New Jersey Opts to Explore Nuclear Options*.)

BPU President Christine Guhl-Sadovy said the new rules mark a "pivotal step toward … making the interconnection process more efficient,"

"Increasing the number of distributed energy resources, including new solar projects, as quickly as possible is a key component of our comprehensive effort to drive down energy costs for ratepayers, and we are delivering on that effort," she said in a statement.

The BPU says the rules will make it easier to get solar and storage facilities online, which the agency said in a statement are "some of the cheapest and fastest resources to come online" and will "reduce the peak energy forecasts for New Jersey."

Doing so "decreases the amount of capacity New Jersey needs to buy, which in turn puts downward pressure on capacity prices for all ratepayers, helping save money via avoided costs," the agency statement said. New Jersey is an importer of electricity because it does not generate enough in-state.

The BPU is working on finalizing a *straw proposal* for a program that would offer incentives to stimulate the development of storage projects. (See *NJ BPU Updates Proposal for Storage Incentives*.) ■

FERC Approves PJM 2024 RTEP Cost Assignment

By Devin Leith-Yessian

FERC has approved PJM's proposed cost allocation for $6.7 billion in transmission upgrades included in the first window of the 2024 Regional Transmission Expansion Plan (RTEP) (*ER25-1811*). (See *PJM Board Approves $6B in Grid Upgrades*.)

The allocation was *opposed by* the Maryland Office of People's Counsel, which argued the need for more transmission is driven predominantly by data center growth in Northern Virginia and that saddling Maryland ratepayers with $789 million, or 16.4% of the total cost allocation, runs against cost-causation principles. It stated that the Dominion locational deliverability area (LDA) is forecast to grow by 44% by the 2029/30 delivery year, whereas the Baltimore Gas and Electric and PEPCO zones are expected to remain flat or see minor growth.

"The vast majority of the [Window 1] facilities will not be in Maryland, nor are they required to serve Maryland loads. Yet the Maryland LDAs will receive a disproportionate 'spill over' of cost responsibility because of how the [solution-based distribution factor] cost component operates under the PJM tariff's method for determining cost responsibility for regional transmission projects," OPC said.

"The costs are driven by the unprecedented context of huge, forecasted data center load growth in Northern Virginia and how that growth impacts the PJM tariff's method for allocation of cost responsibility,"OPC said. "Moreover, these unjust and unreasonable impacts on Maryland customers will continue in future RTEPs, as PJM pursues future procurements of transmission facilities through the RTEP process in response to continued forecasts of huge load increases in the Dominion LDA in future years."

Why This Matters

The first window of the 2024 Regional Transmission Expansion Plan includes nearly $6.7 billion in upgrades, the most significant of which would expand the 765-kV backbone eastbound into Maryland.

| Ameren

While the OPC objected to the figures PJM calculated, the office nonetheless acknowledged the RTO had followed its tariff in the filing. PJM responded to the OPC comments stating that its arguments are out of scope.

"[OPC] is mindful that this is not the proper proceeding in which to challenge PJM's cost allocation under its approved tariff. [OPC] reserves its rights with respect to possible additional remedial measures required to address these infirmities in the PJM tariff as it is being applied."

The commission's May 27 order found PJM had properly followed its tariff and said OPC's arguments are beyond the scope of the proceeding.

"Challenges to the PJM tariff cost allocation provisions are appropriately raised through separately filed complaints and not through protests to the reports of cost responsibility assignments," the commission wrote.

The most significant components of the work would expand the 765-kV network from the John Amos substation running east to a new facility, Rocky Point, located near the Doubs substation in Frederick County, Md. Another 795-kV to the south would run from Joshua Falls to a new Yeat substation, with a 500-kV loop branching off from North Anna, through a new Kraken substation and into Yeat. ■

FERC Clarifies Rules for Markets+ 'Transmission Contributors' Option

Future EDAM Participants Sought Clarification Around the Provision

By Robert Mullin

FERC on May 30 rejected a request by four Western utilities to rehear its approval of the "transmission contributors" option in the SPP Markets+ tariff but provided the utilities clarification on the boundaries of that provision.

The Markets+ tariff, which the commission *approved* in January, identifies two sources of transmission to be used by the market.

The first source is from transmission service providers (TSPs) who have committed assets to the market by signing a Markets+ transmission service provider agreement.

The second is transmission capacity offered by "transmission contributors" — market participants who contribute their transmission rights on the system of a TSP that is not participating in Markets+.

In its Jan. 16 order approving the tariff, FERC found the transmission contributors option to be just and reasonable. It also directed SPP to adopt language the RTO used in a previous deficiency response noting that Markets+ transmission contributors would be responsible for "coordinating transmission schedule changes, curtailments and other operational concerns with the nonparticipating [transmission service provider] and nonparticipating [balancing authority], in accordance with the applicable governing documents and agreements, including applicable" Open Access Transmission Tariffs.

SPP included the change in a compliance filing the commission approved April 17.

'Ownership-like' Concerns

At issue in the May 30 order (*ER24-1658*) was a Feb. 17 complaint filed by PacifiCorp, Portland General, Nevada Power and Sierra Pacific Power. The first two of those utilities have committed to joining CAISO's Extended Day-Ahead Market (EDAM), while the last two are subsidiaries of NV Energy, which is leaning heavily in favor of EDAM.

In their filing, the utilities asked FERC to clarify that no provisions in the Markets+ tariff — or any related proceedings — grants transmission customers "ownership-like" rights on the systems of nonparticipating TSPs or "grants, waives, modifies or otherwise interprets any rights or obligations under the OATT of a non-SPP participant not before the commission" in the proceeding.

PacifiCorp and NV Energy first raised the issue last year soon after SPP filed the Markets+ tariff with FERC. (See *SPP Markets+ Tariff Sparks Concerns for PacifiCorp, NV Energy*.)

As stated in the order, the utilities argued that, "without this requested clarification, the Jan. 16 order would be unlawful to the extent that it could be read to grant a class of transmission customers — in particular, firm point-to-point transmission customers wheeling to another balancing authority area's interface — the unilateral right to exempt themselves from generally applicable OATT requirements, such as the transmission provider's scheduling requirements and redispatch protocols."

The utilities alternatively asked the commission to rehear the matter if it declined to issue such a clarification or if Paragraph 155 of the Jan. 16 order "explicitly or implicitly grants ownership rights to transmission customers taking service on nonparticipating transmission service providers' systems," FERC noted.

In granting the utilities' request for clarification, the commission wrote that "under the Markets+ tariff, Markets+ transmission contributors may contribute only their *transmission service rights* [emphasis theirs] on nonparticipating transmission systems, in accordance with the nonparticipating transmission service providers' OATTs or other governing documents."

The commission went on to clarify that it "agrees with SPP's explanation that the transmission capability of nonparticipating transmission service providers is not available to Markets+ unless an entity that has transmission service rights on a nonparticipating transmission service provider's system makes them available to Markets+, regardless of whether the entity is in a participating balancing authority or not."

The commission added that, because it had granted the utilities' request for clarification, it had dismissed their request for rehearing as moot.

Why This Matters

For a West soon to be divided into two markets, FERC's order should offer clarity around how transmission can be used to move energy across seams.

'Too Narrowly'

FERC dismissed a separate rehearing request by the four utilities, which had argued the compliance directives in Paragraph 154 of the Jan. 16 order could imply that SPP would be able to dictate the terms and conditions of service to transmission customers taking service under the OATTs of nonparticipating TSPs.

"We are not persuaded by rehearing parties' assertions that the Jan. 16 order purports to control transmission service obligations on nonparticipating transmission service providers' systems, and we thus sustain the compliance directives in Paragraph 154 of the Jan. 16 order," the commission wrote.

The commissioners said the utilities were reading "the directives in Paragraph 154 too narrowly, ignoring the broader context of the commission's findings on SPP's Markets+ transmission contributor option in the surrounding paragraphs." ■

Panel Approves SPP Markets+ Phase 2 Governance Transition

Updates from SPP: Xcel Talks Markets+ Before Colorado PUC; 2024 State of the Market Released

By Tom Kleckner

The panel of SPP board members overseeing the development of Markets+ has approved the governance transition plan for the construction phase of the day-ahead market.

The Interim Markets+ Independent Panel (IMIP) also signed off on Phase 2 sector representation for stakeholder groups, a meeting attendance and proxy policy, and the budget for the Markets+ State Committee (MSC) during its May 27 virtual meeting.

The IMIP unanimously endorsed the Markets+ Participant Executive Committee's (MPEC) recommendation to keep the Phase 1 stakeholder groups' rosters until the committee's Aug. 12-13 meeting, which serves as the Phase 2 effective date. Potential Markets+ participants must sign one of three agreements — funding, participation or stakeholder — by July 23 to retain seats for their representatives.

MPEC will vote on stakeholder group nominations during the August meeting in Portland, Ore. (See *SPP Readies Participants for Next Phase of Markets+*.)

IMIP Chair Steve Wright praised MPEC's suggestion for meeting attendance and use of proxies. A stakeholder task force worked to meet the demands of public interest groups and nonprofits, many of which are stretched to cover the various working groups and subgroups.

"This is a good example of how the process works well. I thought there were some legitimate concerns raised with respect to small organizations' ability to participate in the process, and some good compromises were made from the initial proposal," Wright said. "I feel like this is a really strong proposal that aligns with the culture of governance that we want to have as part of the development of Markets+."

The MSC budgeted $389,680 for 2025 expenses. That covers the cost of a full-time equivalent dedicated to the committee and two in-person meetings during the year, and compares favorably with SPP's Regional State Committee in the Eastern Interconnection.

The costs are allocated to Markets+ participants. The Western Interstate Energy Board provides independent staffing for the MSC, which is composed of state regulators from the West.

Xcel Defends Markets+ Decision

Joe Taylor, who represents Xcel Energy operating subsidiary Public Service Company of Colorado (PSCo) on MPEC, explained the utility's decision to join Markets+ rather than an RTO during *testimony May 27* before the state's Public Utilities Commission.

Taylor said the company is concerned about long delays in grid operators' interconnection queues.

"It gives us pause to turn over those activities to an RTO," he said. "The ability to plan and build are important considerations."

A 2021 *state law* requires transmission-owning utilities to join an organized market by 2030. Tri-State Generation and Transmission Association, Colorado Springs Utilities and the Platte River Power Authority have all chosen to become full RTO members of SPP's *Western expansion*.

PSCo has estimated it will be assessed $20 million in implementation costs for Markets+.

MMU Releases 2024 Market Report

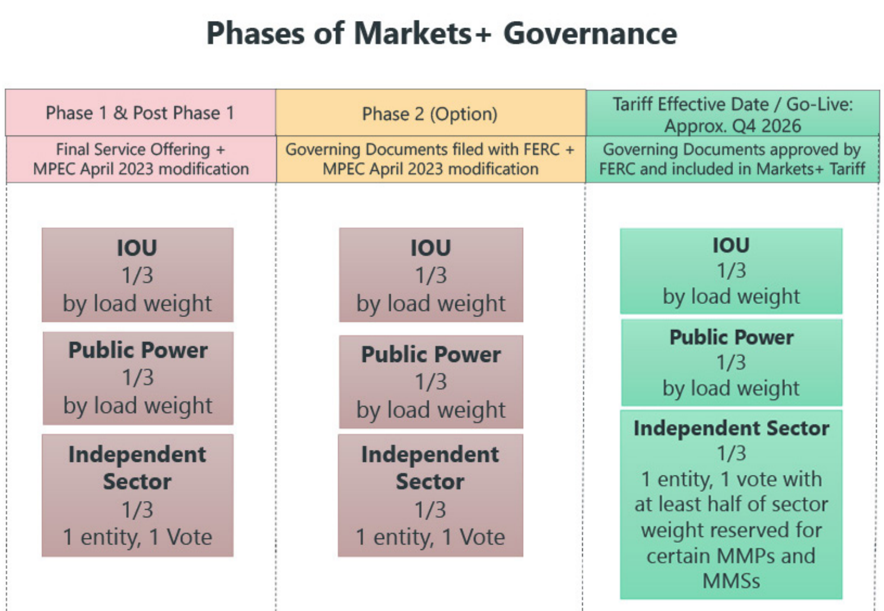
SPP's Market Monitoring Unit has released its annual *State of the Market report* for 2024 and continues to find the Integrated Marketplace to be competitive.

The Monitor shared a draft with stakeholders during the quarterly Joint Stakeholder Briefing in May. (See "MMU's Draft Market Report," *2025 'Challenging' Year for SPP, Exec Says*.)

The MMU said many of the themes identified in previous years — resource adequacy challenges and increasing renewable generation — persisted in 2024. The market continues to see escalating load growth with a "high likelihood" that it will continue in future years.

Intermittent resources continue to play an ever-growing role in the SPP markets, with increasing variability and uncertainty of supply, out-of-market actions to ensure system reliability, higher make-whole payments and negative prices, according to the report.

The MMU will host a *webinar* June 12 to discuss the report. ■



Markets+ governance during Phases 1 and 2 | *SPP*

Company Briefs

ENGIE Strikes Deal to Develop BESS Projects in Texas, California

ENGIE North America last week announced a partnership with CBRE Investment Management to build 31 battery energy storage system projects across Texas and California.

As part of the deal, ENGIE will retain a controlling share of the projects, which will add 2.4 GW to the ERCOT and CAISO grids.

More: *Chron*

National Grid Wraps up $1.74B Sale of U.S. Onshore Renewables Unit

National Grid last week announced it has completed its $1.74 billion deal to sell its U.S. onshore renewables business, National Grid Renewables, to Canadian investment firm Brookfield Asset Management.

National Grid agreed to sell the unit in February as it is seeking to focus on its networks operations and streamline its business.

More: *Renewables Now*

Solar Manufacturer Meyer Burger Lays Off Hundreds in Arizona

Meyer Burger has laid off its entire staff of 355 employees at its solar module manufacturing production facility in Goodyear, Ariz.

The company is also shutting down operations at a facility in the process roughly a year after opening it. Meyer Burger said it has "been unable to obtain the refinancing that would enable it to continue the affected operations."

More: *Phoenix Business Journal*

Federal Briefs

NRC Approves NuScale's Bigger Nuclear Reactor Design

The Nuclear Regulatory Commission last week approved NuScale Power's design for 77-MW reactors, clearing a hurdle for the company as it seeks to be the first to build a small modular reactor in the U.S.

NuScale sought approval for the design to improve economics and performance of its planned small modular reactors (SMRs), after having originally received approval in 2020 for a 50-MW design.

NuScale is the only U.S. company with an approved design.

More: *Reuters*

DOE Announces Termination of 24 Projects Worth $3B

Energy Secretary Chris Wright last week announced the termination of 24 awards issued by the Office of Clean Energy Demonstrations (OCED) totaling more than $3.7 billion.

Of the 24, 16 were signed between Election Day and Jan. 20. The projects primarily include funding for carbon capture and sequestration and decarbonization initiatives.

More: *DOE*; *Canary Media*

TVA Begins Construction on Kingston Energy Complex

The Tennessee Valley Authority last week began construction on its $1.8 billion natural gas Kingston Energy Complex.

The natural gas power plant will replace the existing Kingston Coal Plant, which will shut down by the end of 2027 as the natural gas comes online. TVA also plans to add solar panels and battery storage to the facility.

More: *Knoxville News Sentinel*

State Briefs

ALABAMA

Cavanaugh to Leave PSC to be State Director for Rural Dev

Public Service Commission President Twinkle Cavanaugh last week announced she will leave the commission to become the state director for rural development under the U.S. Department of Agriculture.

Cavanaugh left the PSC on June 1. USDA announced the move along with other appointees.

In her new role, Cavanaugh will oversee loan and grant programs for rural areas, technical assistance for farmers, and housing assistance and home repair programs for rural residents.

More: *Inside Climate News*; *USDA*

CALIFORNIA

SCE to Pay $82M in Lawsuit Stemming from 2020 Bobcat Fire

Southern California Edison last week agreed to pay the Justice Department $82.5 million stemming from the 2020 Bobcat Fire.

The settlement stemmed from a 2023

lawsuit filed by federal prosecutors on behalf of the U.S. Forest Service against SCE and Utility Tree Service to recover costs from fighting the fire.

SCE agreed to pay the settlement within 60 days of its effective date, May 14, without admitting wrongdoing or fault, prosecutors said.

More: *The Associated Press*

SoCalGas Begins Restoration in Rancho Palos Verdes

SoCalGas last week said it will begin restoring natural gas service to homeowners in phases in Rancho Palos Verdes affected by recent land movement.

The restoration, which is expected to take between four and five weeks, follows months of slowed land movement. In 2024, accelerating land movement forced SoCalGas to shut off natural gas service. Last July, the company halted service to multiple homes while relocating pipelines and intensifying safety inspections. Now, after extensive coordination with city officials and experts, SoCalGas has determined conditions in certain neighborhoods are stable enough to begin restoration efforts.

More: *KTTV*

INDIANA

URC Chair Huston to Retire in January

Utility Regulatory Commission Chair Jim Huston last week announced he will retire in January.

Huston was appointed by then-Gov. Mike Pence in 2014 and was appointed chairman two years later.

More: *Indiana Public Media*

MAINE

DEP Fines Tower Solar Partners for Water Pollution

Solar company Tower Solar Partners has been fined $236,000 by the Department of Environmental Protection for polluting the Kennebec River during construction of a 5-MW array in Embden.

Multiple violations were reported to the department over a six-month period between 2022 and 2023, as sediment runoff ran into the river from nearby Alder Stream.

Tower Partners has since fixed the problems and installed a stormwater maintenance system to help manage runoff.

More: *Maine Public Radio*

NEVADA

Bill to Ensure Refunds When Utilities Overcharge Passes

The Senate unanimously voted to pass a bill that would ensure customers receive full refunds with interest for utility overcharges.

The bill would also address high utility bills by shifting some cost volatility back to utilities and extending regulatory timelines for rate case reviews. Two weeks ago, regulators disclosed that NV Energy overcharged more than 80,000 customers more than $17 million over several years, with only 20,000 receiving partial six-month refunds.

The bill is now headed to Gov. Joe Lombardo's desk.

More: *Nevada Current*

NORTH CAROLINA

Charlotte Votes to Adopt New Climate, Energy Goals

Charlotte City Council last week voted unanimously to adopt plans to reduce communitywide greenhouse gas emissions 72% by 2035 and reach net-zero by 2050.

Transportation emissions account for most of the city's annual greenhouse pollution. The city plans to replace its light-duty vehicles with EVs by 2035 and the entire fleet by 2050.

More: *WFAE*

OHIO

PUC Approves AEP Building On-site Generators at Data Centers

The Public Utilities Commission last week approved AEP's plans to install onsite power generators at two large data centers.

The decision allows the utility to build onsite power generators for the data centers that use solid oxide fuel cells and natural gas to generate electricity, instead of relying only on the grid.

The systems will be paid for by the utility and data centers over the course of a six-year contract with Amazon Web Services and a 15-year contract with Cologix.

More: *WOSU*

OREGON

Jury Awards $50M to 2020 Labor Day Fire Survivors

A Multnomah County jury last week awarded about $50 million to 10 survivors from the state's 2020 Labor Day wildfires, the latest in a growing series of verdicts against PacifiCorp.

PacifiCorp has now been ordered to pay more than $385 million to individual plaintiffs following a 2023 class-action ruling that found it liable for negligently causing four major wildfires by failing to shut off power during extreme fire conditions.

More: *The Oregonian*

PGE Appeals Portland's Denial of Forest Park Tx Project

Portland General Electric is challenging the Portland City Council's decision to reject a transmission upgrade project in Forest Park that would require the utility to clearcut more than 370 trees on about 5 acres.

PGE filed a notice of intent to appeal with the state Land Use Board of Appeals. Councilors in May unanimously voted to overturn approval of PGE's proposal by a city hearings officer.

The utility said the Harborton Reliability Project — which seeks to rewire a 1970s transmission line and add a second line in the existing right of way in the park — is necessary to avoid blackouts in the region.

More: *The Oregonian*