JANUARY-FEBRUARY 2026 • VOL. 84 / NO. 1

PUBLIC POWER MAGAZINE

AMERICAN PUBLIC POWER ASSOCIATION

ENSURING RESOURCE ADEQUACY

Why FEMA assistance is critical for community resilience. p.20

How data centers are changing the generating landscape. p.28

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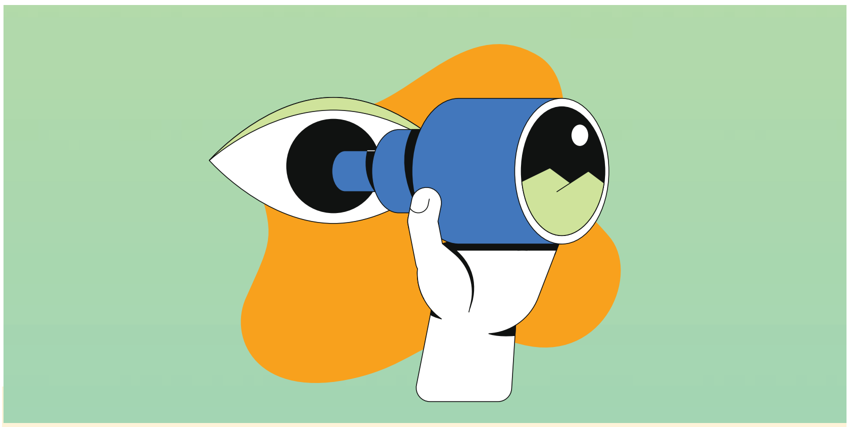

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Public Power Magazine (ISSN 0033-3654) is published six times a year by the American Public Power Association, 2451 Crystal Drive, Suite 1000, Arlington, VA 22202-4804. © 2026, American Public Power Association. Opinions expressed in articles are not policies of the Association. Periodical postage paid in Arlington, Va., and additional mailing offices.

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AMERICAN PUBLIC POWER ASSOCIATION
Powering Strong Communities

The American Public Power Association is the voice of not-for-profit, community-owned utilities that power approximately 2,000 towns and cities nationwide. We represent public power before the federal government to protect the interests of the more than 55 million people that public power utilities serve across the United States and its territories. We advise on electricity policy, grid technology and operations, and workforce development in support of safe, modern, and resilient utilities.

Postmaster, send all address changes to:

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2451 Crystal Drive, Suite 1000

Arlington, VA 22202

Public Power's Quest to Ensure Resource Adequacy

Photo courtesy EPB Chattanooga, Tennessee

BY SCOTT CORWIN, PRESIDENT AND CEO, AMERICAN PUBLIC POWER ASSOCIATION

As we again prepare to welcome our members to Washington for our annual Legislative Rally, the phrase often heard repeated throughout the halls of Congress when talking about energy is "resource adequacy."

In its simplest terms, resource adequacy means having enough capacity and reserves for grid operators to maintain the balance of supply and demand across an electric system. But, having enough capacity (power when it is needed and the transmission and other infrastructure to deliver it), having enough security to protect the grid components, being able to afford the rising costs to produce and the deliver the power necessary, and deciphering what the levels of projected growth in demand over various time periods will be are some of the toughest issues facing our industry today.

The North American Electric Reliability Corporation continues to warn us about potential gaps in available capacity during winter and summer peak periods. Other policymakers are starting to listen and talk about these issues, but APPA members are living the realities every day. Public power remains laser focused on providing safe, affordable, reliable power and is applying new technologies and strategies to meet this mission for the communities we serve. We are also continuing the long-held tradition of working together and with others at the local, state, and federal levels to move forward on major efforts.

This issue of *Public Power* highlights your stories and experiences related to resource adequacy, from how utilities are moving ahead with big infrastructure projects (see page 12) to working with data center customers (see page 28) and navigating the latest changes in the capacity markets (see page 6). Our quick breakdown of resource adequacy (page 18) might be helpful to you in defining this concept to those outside of our industry, whether for policymakers or community members.

While utilities have showcased innovation amid the bevy of challenges, Congress must do its part to ensure resource adequacy, and to help you overcome supply constraints and rising costs. For our part, the American Public Power Association has been hard at work advocating for changes on the regulatory and legislative fronts that will help our members not only build infrastructure, but access needed funding mechanisms and technology to rise to this challenge. We are pushing for faster permitting, planning certainty, and interagency coordination, and policymakers are beginning to embrace these ideas.

On the resilience side, this issue also shares the perspective of utilities that have recently worked with the Federal Emergency Management Agency's Public Assistance Program on why the agency's assistance is critical, and how reforms under consideration could make a difference for utilities and the federal government alike (see page 20).

The energy landscape is as promising as it is ominous, and I'm optimistic public power can meet this moment. Just as your perspective is important in informing your policymakers at the state and federal levels, your input to us at APPA into how policy and regulations affect your work helps shape our priorities. As we prepare for the Legislative Rally, I invite you to weigh in on the latest policy resolutions put forth by APPA members and to read over our updated issue briefs. Please let our policy team know should you have further insights or feedback to inform our advocacy work in 2026 by emailing Policy@PublicPower.org.


APPA ACADEMY
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Exchange ideas and gain insights from industry experts and fellow public power utility executives at the **CEO & Utility Managers Roundtable.**
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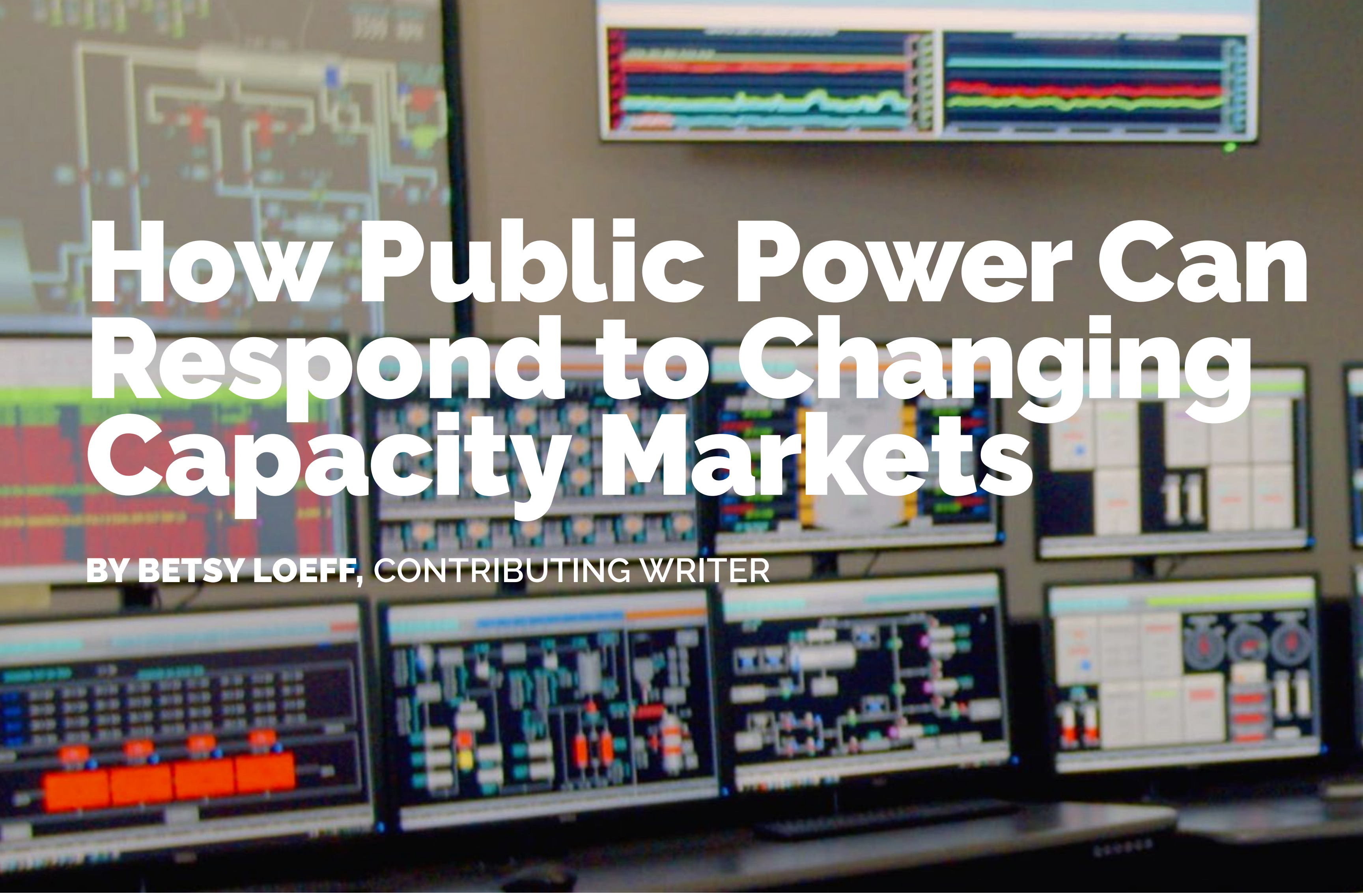


How Public Power Can Respond to Changing Capacity Markets

BY BETSY LOEFF, CONTRIBUTING WRITER

As concerns about the costs of electricity rise, utilities, regulators, and consumers are looking into what's putting upward pressure on prices — and what can be done to mitigate this pressure.

For utilities and customers in areas served by regional transmission organizations with capacity markets, a recent spike in capacity costs has been a major driver of increases. PJM Interconnection saw prices jump 830% in 2024 auctions and 22% in 2025. A temporary price cap of $333.44 per megawatt per day was set in the PJM market in 2025 following an agreement with the state of Pennsylvania. ISO-New England's 2024 jump in the forward capacity auction was around 38%. The Midcontinent Independent System Operator's summer auction rate rose from about $30 per megawatt per day in 2024 to $666 per megawatt per day in 2025.

Each of these RTOs is examining and implementing changes to its capacity markets. For public power providers within PJM, MISO, and ISO-NE, technology, partnerships, and agility could all come into play to secure the power supply they need while keeping an eye on costs.

Rethinking Value

As with many issues in the power sector, a confluence of forces is driving the surge in capacity market prices.

"The resource transition itself is one driver of change in capacity markets," said Rao Konidena, president Rakon Energy, a consulting company. "A lot of coal plants are retiring at the same time a lot of renewables are coming online."

"You can't compensate a 20-megawatt gas plant and a 20-MW wind farm the same way," said Dave Meisinger, CEO of the Connecticut Municipal Electric Energy Cooperative, which provides power and services to six public power providers in the

Constitution State. “These resources are just not going to be operating the same way. The gas plant’s going to operate more frequently and run on a more predictable timeline. You have to find ways to account for that.”

Several markets have done just that, and most are compensating generators based on accredited capacity, which better reflects capacity’s actual value. For example, a gas plant would receive a capacity value close to its nameplate capacity because it’s dispatchable at will.

“If you build a 100-MW gas plant, you typically get 90 MW of accredited capacity. With renewable resources, their contribution to capacity is about 30%,” explained Patrick Bowland, CEO and general manager of the Michigan Public Power Agency. He added that 100 MW of solar delivers 50 MW or less of accredited capacity, while 100 MW of wind only delivers 15 MW. “That’s one reason reserve margins started to decline.”

Considering Co-Location

Another cost driver is the extended timeline for interconnection. “Historically, when somebody would interconnect a new resource, it would be a big plant: 500 MW or 1,000 MW,” Bowland continued. “When you’re interconnecting smaller renewable projects that are 25, 50, or 100 MW, it takes dozens and dozens of plants to equal the same capacity.”

This dynamic amplified the number of interconnection requests over the past several years, creating what Bowland called “gigantic backlogs to interconnect resources to the transmission grid.” He added that it used to take about two years from filing an interconnection application to obtain an interconnection agreement. It now can take four to five years.

"If we have a power supply resource with an existing interconnection, evaluating the economics of locating another power supply resource behind the same meter is an important due diligence step, particularly for renewable resources like wind and solar."

PATRICK BOWLAND, CEO AND GENERAL MANAGER, MICHIGAN PUBLIC POWER AGENCY

This is one reason MPPA is looking at surplus interconnection. "If we have a power supply resource with an existing interconnection, evaluating the economics of locating another power supply resource behind the same meter is an important due diligence step, particularly for renewable resources like wind and solar," Bowland said. "It could be a battery or gas project, but it's using the same point of interconnection. The power it produces is going to the same meter the wind or solar is using."

"The transmission interconnection has to be much faster," Konidena said, adding that it can take as much as 10 years to build new lines.

A similar solution to interconnection delays is the co-location of load and generation at the same site. "If you have a load interconnection request and a generator interconnection request, they'll take two or three years sequentially — that means six years," Konidena said. "A co-location request can be studied in one instance."

The argument for co-location is that it enables data centers to access power more quickly while saving utilities time and money by eliminating transmission builds. In December, the Federal Energy Regulatory Commission ordered PJM "to establish transparent rules to facilitate service of [artificial intelligence]-driven data centers and other large loads co-located with generating facilities." This type of market reform could help power providers keep rate impacts down and still meet capacity requirements.

Shorter Cycles

Weather is yet another driver of price fluctuations. Konidena pointed out that storms — such as the major winter storm in December 2022 that affected PJM territory — can disrupt supply chains and asset performance. "If a gas pipeline freezes, the market operator can't rely on its gas plants," he said. "The capacity grid operators thought would be online during the storm can quit performing, and that's also driving the change in capacity markets."

Among those changes are tighter timelines. In New England, annual capacity auctions occur approximately three years before the annual capacity commitment period to which they relate. Meisinger mentioned proposed changes in the ISO-NE markets on timing and seasonality. "Instead of three years in advance, it will be a month or so before the period and thus a 'prompt' market. They're also proposing to divide it into seasonal markets because generation resources operate differently based on weather, and you also have different levels of demand in the winter versus the summer," he added. This more frequent auction schedule is proposed to take effect in the 2028–2029 capacity period.


Your
Outage,
Under
Control.

"Rather than wait around to see what the capacity price is going to be, when you really have no option but to take that price and pay it, we're looking for counterparties who might own resources and can sell us capacity."

DAVE MEISINGER, CEO, CONNECTICUT MUNICIPAL ELECTRIC ENERGY COOPERATIVE

This change is going to shorten planning timelines, but that's happening coast to coast. "The planning horizon has shrunk because technology and political changes have accelerated so much that you can't plan the way you used to," Bowland said. "You have to be much more agile."

In his consulting, Konidena has observed some public power utilities still using three- or four-year planning cycles for their resources. He said most public power providers should now consider integrated resource plans on a one- to two-year horizon because of the rapid changes affecting capacity needs and prices.

New Strategies

Konidena believes utilities with transmission should embrace grid-enhancing technologies to combat high capacity costs. "Basically, these technologies allow you to get more throughput out of the existing system, free up capacity, and interconnect more resources," he explained.

Among these technologies are sensors combined with analytics that factor in line temperatures, wind speeds, weather forecasts, and historical data to help grid operators increase or decrease the power flowing on transmission lines.

Getting more from existing assets is part of MPPA's multipronged strategy to deal with today's capacity markets. "The best way to describe it is that we're trying to extract as much value as we can from assets we own, control, or manage, whether these are located within our member communities at the distribution level or connected to the transmission grid," Bowland said. This includes "repowering," which means the organization is no longer going to burn coal — it has state legislative mandates to meet — but it will continue to burn gas. "We're reducing our carbon footprint while maintaining the same level of capacity instead of retiring a plant."

In Connecticut, Meisinger said capacity isn't the biggest headache that his joint action agency's members see on their monthly invoice, but it could be. "It's creating the desire to find new strategies," he added, "and there's one in particular that is theoretically out there but not as many parties take advantage of it."

He's talking about bilateral transactions. "Rather than wait around to see what the capacity price is going to be when you really have no option but to take that price and pay it, we're looking for counterparties who might own resources and can sell us capacity. We can negotiate a longer-term deal and fix the price," Meisinger explained. The agency already employs a hedging strategy for most of its energy portfolio, Meisinger added.

Another thing public power providers can and should leverage is load itself. MPPA is exploring a partnership with an aggregator to provide the software and expertise for demand response programs serving both residential and commercial-industrial customers. "Our interests are about resource adequacy," Bowland said. "We want to be able to reduce our peak load so that we can reduce the capacity obligation that we have. It made sense for us to do this through a partnership with people who have already cut their teeth in that space."

Konidena also counsels utilities to consider demand response to address capacity issues, but he warns change is headed to that world, too. "Market monitors are focused on demand response not performing as expected, and they're tightening the rules at the same time when we need more demand response on the grid to reduce consumer prices," he said.

Specifically, monitors of PJM and MISO are looking at holding market participants responsible for the performance of individual loads within the aggregator's collective response. Monitors would also like to see loads curtailed for four continuous hours, not coming and going at will. If these changes occur, they could drive some curtailment participants and market players out of the markets, so it's something to watch.

But don't just watch, said Meisinger. Get involved.

"It's a hallmark of public power to participate in regulatory processes and advocate for what we need both individually and collectively as part of the public power community," he said. "We do a lot of that advocacy jointly with the other joint action agencies here in New England, with our regional public power trade association, and with [the American Public Power Association]. We do have a voice. It's part of the value proposition that we bring to our members and ultimate ratepayers."

"Market monitors are focused on demand response not performing as expected, and they're tightening the rules at the same time when we need more demand response on the grid to reduce consumer prices."

RAO KONIDENA, PRESIDENT, RAKON ENERGY

PLANNING, FLEXIBILITY, AND PUBLIC TRUST

HOW PUBLIC POWER IS ADVANCING NEW PROJECTS

BY LISA COHN, CONTRIBUTING WRITER

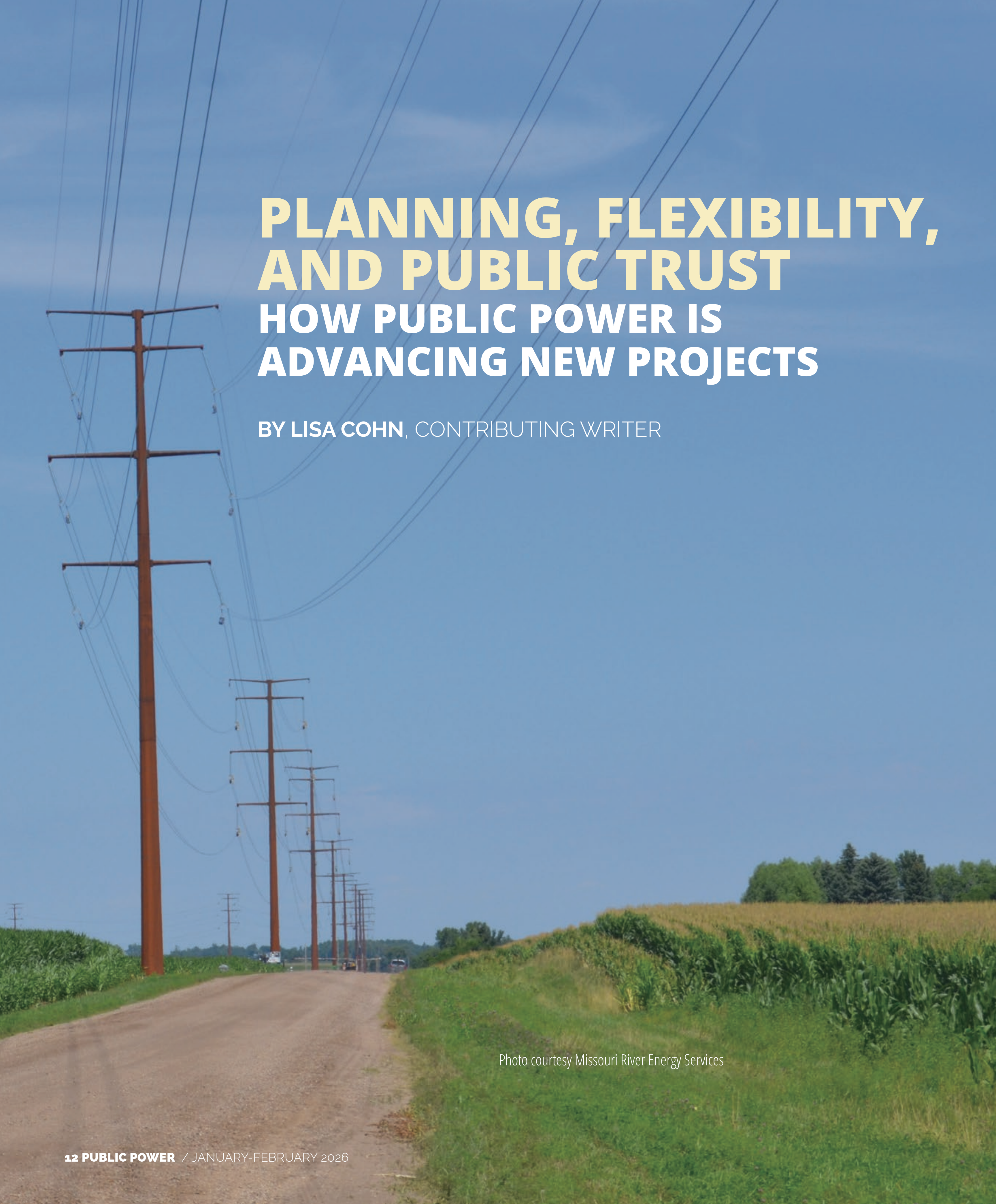


Photo courtesy Missouri River Energy Services

In the face of burgeoning demand, whether from data center growth, electrification, or increasing population, public power utilities are focused on building new infrastructure. Projects range from replacing aging power plants to adding renewable energy to meet clean energy goals and building new transmission lines.

A survey of American Public Power Association members found that dozens of public power utilities are developing projects, including early-stage partnerships in small modular nuclear reactors, natural gas plant upgrades, and new geothermal plants, many in the 20-megawatt to 100-MW range, according to comments filed with the Department of Energy. Larger public utilities have plans that could add gigawatts to their systems. The comments were in response to the DOE's Speed to Power initiative, which aims to accelerate large-scale grid infrastructure projects.

But projects are sometimes slowed or canceled because of supply chain constraints, permitting delays, tariffs, community opposition, and an uncertain regulatory environment.

To help move projects forward, public power utilities are focusing on being ready to respond to interconnection delays, changing market conditions, and other curveballs as they crop up. The utilities are learning to be nimble — such as adjusting to tariff pause opportunities to buy batteries when there are reduced price impacts. And they're engaging with their communities to build understanding of the need for and potential benefits of new projects.

Consistent Uncertainty

In California, Glendale Water & Power is in a power-supply crunch as it seeks to replace aging generation and increase its clean energy portfolio. GWP's primary power resources are imported renewable and thermal generation, with local generation used to meet peak load and ensure reliability. The public power utility decided to retire the majority of its natural gas-fired generating units at the Grayson Power Plant, GWP's only local generation resource, because they would no longer be able to economically comply with air emissions rules past 2023. To replace the obsolete generators, which began operations in the 1950s-1970s, GWP chose to repower with 75 MW/300 megawatt-hours of battery storage and 56 MW of combustion engines. The utility has only 47 MW of local generation while the project is being built, said Scott Mellon, the utility's general manager.

The pressure is on to build the Grayson Repowering Project as soon as possible, but that's not so easy. Challenges included public opposition, extended supply chain delays, tariffs, and cost increases. In addition, data centers are willing to pay higher prices to speed equipment delivery, which raises prices across the market, Mellon said.

GWP is focusing on being as flexible as possible to move the project along, switching gears and reshuffling plans when needed. Planning ahead has been critical, too.

"We had to be very aggressive in our purchasing and identifying the hardware that we needed as early as possible," Mellon said. "Some of the lead times are 1.5 years to two years. We had to rework the plant arrangement to work around significant delays in delivery of some major equipment," he said.

To cope with tariffs on batteries from China, when the Trump administration issued a 90-day pause on the tariffs, GWP and its EPC contractor were able to take advantage of earlier production slots that became available when other buyers canceled their projects due to the imposition of tariffs. As a result, the utility received the batteries four months early at the cost of working out an on-site storage scheme and accelerating the remaining uncompleted foundations. This helped avoid the higher tariffs that would have been levied after the pause if GWP had stayed with the original delivery schedule.

"We had an opportunity to move. Luckily, we were more agile than a municipal utility usually can be," Mellon said.

"Going into this knowing that structurally, this wasn't a normal project, we couldn't look at it within a normal methodology. We had to have some flexibility because there was a consistent level of unknown that we knew we were working with," Mellon said.

Prioritizing Buy-In

Missouri River Energy Services is focusing on engaging the communities along the route about its plans to build the Big Stone South to Alexandria transmission project (connecting South Dakota and Minnesota), which it is developing with Otter Tail Power Company. Community engagement is also a key goal of its effort to construct a 145-MW natural gas plant near Toronto, South Dakota.

The transmission project includes a new right-of-way, and landowners are concerned that the transmission corridor may affect their use of their property. "There's a lot of sensitivity from irrigation folks who are concerned about how it will affect irrigation," said Terry Wolf, vice president and chief operating officer at MRES.

To address these concerns, the utilities held three rounds of open houses before they filed an application for the permit for a 100-mile route, he said. During the meetings, the transmission owners explained that the transmission line is needed to provide reliability and to help meet Minnesota's ambitious clean energy targets, as it will help transport renewable energy.

"We said, 'Here are the corridors we're considering,' at the meetings, and in response to feedback, we kept refining the route," he said.

MRES has been working on the project for three years — since it gained approval from the Midcontinent Independent System Operator — in part because it wanted to do as much community outreach as possible early on.

"We're trying to do things on the front end to avoid landowner complaints on the back end," Wolf said. "To the extent that we can squeeze landowner outreach in the front end, we make the process more efficient." Such early planning could cut the project timeline in half, he added.

The transmission line will run through a corridor where a transmission project was opposed in the 1970s. Back then, farmers tore down the project's lattice structures with their tractors.

MRES and Otter Tail Power are also focused on assembling the right engineering and design team to execute the project efficiently.

For its proposed natural gas and diesel plant near Toronto, MRES is focusing on communicating to the local community the need for reliability. During the region's cold winters, utility customers can't rely solely on the area's wind resources, which provide a significant amount of power.

"If the wind calms down, we've got to have some other kinds of backup fuel, or people could die," Wolf said.

For the Toronto generation project, landowner concerns are also the biggest challenge. The project includes a relatively short 4-mile transmission line. MRES also has been communicating to ensure that residents understand the project is not related to a proposed data center that's sparking concerns.

A second challenge to power plant development is uncertainty about whether MRES will have to pay for infrastructure upgrades to interconnect with MISO. Preliminary studies suggest that no upgrade will be needed.

MRES is working to cut costs by procuring materials — especially transformers, which can have a three-year lead time — as early as possible to avoid cost increases. Finding affordable contractors is also an issue.

Risk is inherent in this type of project, Wolf said. "Interconnection costs could come in higher than expected, a

> "We had to have some flexibility because there was a consistent level of unknown that we knew we were working with."
>
> **SCOTT MELLON,** GENERAL MANAGER, **GLENDALE WATER AND POWER,** CALIFORNIA

permit denial from the state or county could stop construction. Material delays and costs are an issue, like any large construction project."

Pathways to Change

For Freeport Electric in New York state, a main challenge has been navigating uncertainty about grant funding through the DOE, said Eric Rosmarin, superintendent of electric utilities.

The utility is looking at ways to incorporate the state's Climate Leadership and Community Protection Act into its infrastructure and grid. The act calls for 70% zero-carbon electricity by 2030 and 100% by 2040. Freeport Electric applied to the DOE for a $200,000 technical assistance grant for that project.

"I'm hearing from other utilities that even though they've had awards from the federal government, they're not even sure if they're getting the money now," he said.

Supply chain delays have also been a challenge for Freeport, but they were worse during the COVID-19 pandemic, when the utility was focused on infrastructure projects and experienced delays with materials and contractors. Right now, obtaining transformers is the biggest supply chain issue, Rosmarin said.

Also of interest to Freeport Electric is energy storage. Because peak prices can be high, the utility wants to charge batteries at night, when prices are lower, and then discharge the batteries when prices are high. Freeport isn't ready to order batteries, so Rosmarin isn't sure how tariffs on batteries from China will affect acquisition.

Like Freeport Electric, many public power utilities are trying to add more renewable energy into their mix to meet city or state goals. Many are also looking at transmission and generation projects to meet growing demand. Wolf and Mellon offered a few words of advice for public power utilities in that situation.

> **"Get the team built that will develop the project — your engineering, legal, and consultants — and make sure land rights are established to help avoid the traditional pitfalls. And you need a supportive board to understand and inform people early and often."**
>
> **TERRY WOLF,** VICE PRESIDENT AND CHIEF OPERATING OFFICER, MISSOURI RIVER ENERGY SERVICES, SOUTH DAKOTA

"Get the team built that will develop the project — your engineering, legal, and consultants — and make sure land rights are established to help avoid the traditional pitfalls. And you need a supportive board to understand and inform people early and often," Wolf said.

Mellon also pointed to the need to form a team.

"Find an [engineering, procurement, and construction] contractor who has some experience. Understand that you are working together to get something accomplished — it's not them versus us, it's not them and me, it's us together," he said.

Reshaping Policy to Help

Meanwhile, APPA is working on the policy front to help its members speed up project deployment.

Latif Nurani, senior regulatory counsel at APPA, said an advocacy priority is to reform the permitting process for infrastructure projects, including streamlining the National Environmental Policy Act to speed federal permits while maintaining appropriate environmental oversight.

APPA's goals for speeding permitting include a request for Congress to change permitting to give public power utilities the certainty they need to invest in generation, transmission, and distribution infrastructure. In addition, public power advocates are requesting that federal policymakers digitize permitting and establish an interagency sharing portal that allows information to be shared with all federal agencies simultaneously.

APPA also asked the DOE to ensure public power utilities receive financial and technical help. APPA called for the DOE to enable groups of utilities to jointly build generation and transmission projects and apply for grants as a single organization, such as through JAAs. And APPA called for the DOE to help boost certainty by streamlining applications for technical and financial assistance.

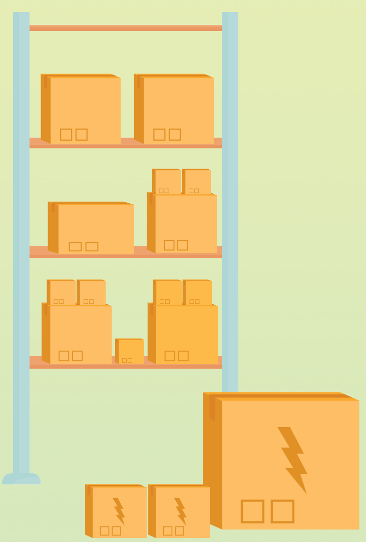
"A 'one-stop shop' — describing the range of programs available and eligibility requirements — would allow for more utilities to make use of the programs. Furthermore, greater certainty around the durability of assistance programs will allow beneficiaries to more effectively plan and execute on projects that expand grid capability," APPA said.

APPA's comments also suggest that the DOE could analyze proposed Environmental Protection Agency rules to identify whether they'll affect reliability or resource adequacy.

What's Involved in Resource Adequacy?

Utilities and grid operators are focused on making sure the electric grid can always meet demand. This is called resource adequacy. Ensuring resource adequacy involves short- and long-term planning, coordination, and maintenance.

Here's a breakdown of key factors and challenges behind resource adequacy.



ENOUGH CAPACITY

On the surface, this is a simple equation of whether there is more generating capacity in operation than the peak usage on high demand days.

$$\frac{759{,}180\ \text{MW}}{1{,}326{,}426\ \text{MW}}$$

759,180 MW — U.S. peak demand, July 2025[i]

1,326,426 MW — Total U.S. nameplate capacity, including more than 870,600 MW of firm capacity[ii]

However, the nameplate capacity does not equal output, and operators are looking at how to better measure total capacity based on how often it gets dispatched.

SUFFICIENT TRANSMISSION

As of early 2025, **468,582 MW** of new generating capacity was under development, including 143,247 MW that have been permitted or are under construction.[ii] Since 2000, less than 20% of generation projects have been completed, in part due to increasing wait times to interconnect to the grid.[iii]

Building more capacity is one step, delivering the generated power to whoever will use it via transmission lines is another.

41,000 miles

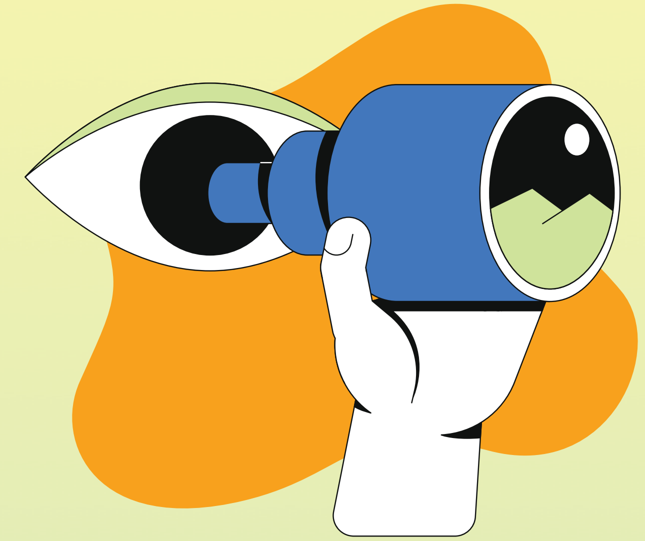
As of January 2026, **41,000 miles** of transmission lines were in some stage of development across the U.S. (through 2035)[iv]

863 projects

Of the **863** transmission projects in the pipeline, **390** are facing delays.

3,600+ miles

Projects totaling more than **3,616** miles of transmission lines were added between 2023 – October 2025[v]



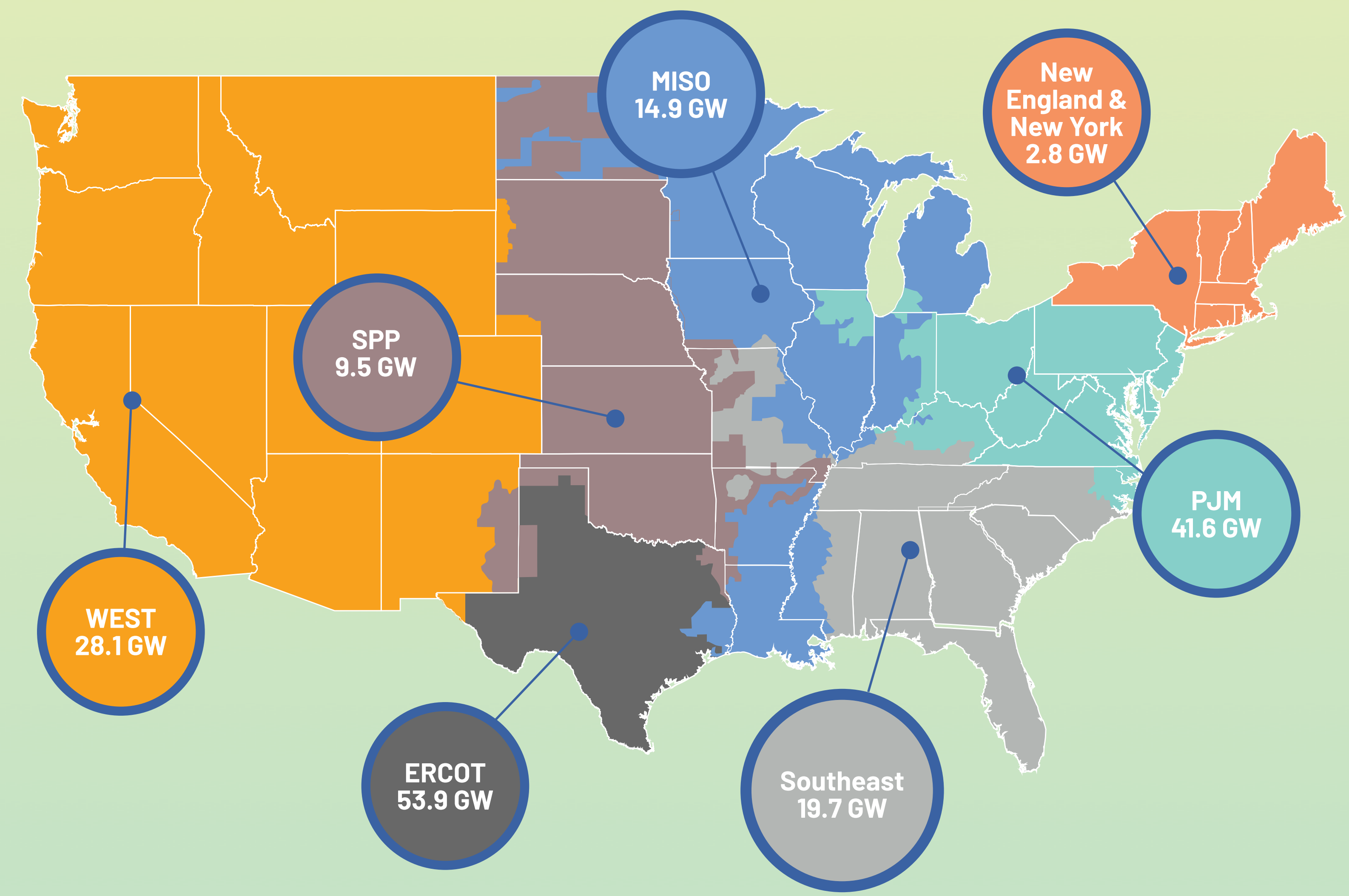
ACCURATE FORECASTING

With more variable generating capacity sources on the grid, operators need to predict not only how much load will be needed in the future, but when it will be needed.

In many regions of the U.S., electricity demand tends to peak in the later afternoon during July and August.

PROJECTED PEAK LOAD GROWTH, 2026-2032

NERC's Long-Term Reliability Assessment projects peak demand to grow more than **170 gigawatts** through 2032.[iv] However, this demand is not spread evenly across the U.S.



Sources:
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REBUILDING TOGETHER:

HOW FEDERAL AID HELPS PUBLIC POWER BOOST COMMUNITY RESILIENCE

BY ADAM PATTERSON, CONTENT SPECIALIST, AMERICAN PUBLIC POWER ASSOCIATION

Photo courtesy Kerrville Public Utility Board, Texas

Every community across the U.S. is at some level of risk for experiencing a sudden loss of infrastructure and other damage, whether from an ice storm, hurricane, tornado, flood, wildfire, or other natural disasters. While public power utilities are especially diligent in addressing service interruptions, emergency events can bring widespread infrastructure damage that necessitates additional support and resources to get communities back on their feet.

Preparing communities to be more resilient is a complex calculation of potential risk, planning for grid hardening, and effective emergency response. Public power utility staff possess technical knowledge and understanding of grid systems, familiarity with the communities they live in, and relationships with other local organizations. As not-for-profit entities, public power utilities make these calculations with affordability for their communities top of mind.

Many public power utilities have benefitted from additional support from the Federal Emergency Management Agency, in the form of reimbursement and resources, as part of their recovery efforts. APPA members have also received FEMA grants to mitigate against risks and future natural disasters. This support and financial assistance has been invaluable to communities in recovery, helping utilities have more peace of mind in restoring essential energy services to their communities. Because this support is so critical, the American Public Power Association and its members have been supportive of efforts in Congress to reform aspects of FEMA, especially FEMA's Public Assistance program, to remove administrative burdens and ensure that our members get the help they need as quickly as possible.

Unprecedented Damage and Loss

When heavy rainfall in early July 2025 caused the Guadalupe River to swell, Kerr County, Texas, took the brunt of the flash flooding, both in terms of loss of human life and ensuing infrastructure damage. For Kerrville Public Utility Board, which serves over 24,000 customers throughout greater Kerr County, the event marked 2025 as one of the utility's most challenging years since its municipalization in 1987.

Allison Bueché, director of customer and community relations for KPUB, said the damage to power lines was far greater than any prior disaster, including another major event in 2020.

"In 2020, we had 30 downed poles, and last year we had around 110 from the flood. It was that much more of a significant event for us," Bueché said.

The damage was so extensive that it prompted the utility's first coordination with FEMA for disaster aid and only the second mutual aid request in its history.

Amy Dozier, assistant general manager at KPUB, noted that the federal disaster declaration for Kerr County for the flooding event, on July 6, opened up the option for public assistance to come through from FEMA.

KPUB staff took immediate action to restore service, using their expertise, mutual aid partners and closeness to the residents of Kerr County to move with an exceptional speed. Dozier said customers were surprised by the quickness with which repairs began and service returned.

KPUB staff also found their customers were proactive and enthusiastic in providing material support, offering up kayaks and other items to help with power restoration efforts.

"We even got a call from a customer who said, 'I have a drone if you need me to survey the damage for you,'" Dozier said.

The close coordination and swift response further improved relationships between KPUB and the broader Kerr County community.

"It was obvious to our customers that we cared about getting everything restored as quickly as possible. And our customers provided a lot of good feedback for us during this difficult event," Dozier said.

KPUB mutual aid teams in action following the 2025 Central Texas Floods. Photo courtesy Kerrville Public Utility Board.

KPUB found the contacts at FEMA to be responsive, knowledgeable, and genuinely committed to providing the support and coordination it needed. Dozier particularly credited the FEMA program delivery manager assigned to their region, Ira Guzeman, with being helpful in navigating the Public Assistance program grant process.

"We've had a great experience with her, and she's been on the ground in Kerrville since August, meeting with us weekly. She's been instrumental in helping us get our claims for public assistance filed," Dozier said.

While KPUB has found FEMA staff to be knowledgeable and supportive, it has faced challenges with the financial reimbursement process. KPUB staff expressed that the uncertainty around the reimbursement timeline is especially noteworthy.

"We've been left with two questions: when do you think this review will be complete and what is the timeline for disbursing funds. While there are people meeting with us every week, they've been telling us in full honesty that they can't give us a clear timeline," Dozier said.

Dozier noted that expediting and clarifying the reimbursement timeline would be a helpful reform, especially for public power utilities that might not have KPUB's level of resources.

"Communication about the timeline from here would be really helpful. Luckily, we're not in a position where we had to borrow money, but other entities could be in a position where they have to take out short-term loans. And it would be greatly beneficial to know what kind of timeframe they're looking at," Dozier said.

"While there are people meeting with us every week, they've been telling us in full honesty that they can't give us a clear timeline."

AMY DOZIER, ASSISTANT GENERAL MANAGER, **KERRVILLE PUBLIC UTILITY BOARD,** TEXAS

Learning the Process

While hurricanes might seem like an annual event for Florida, Ocala, an inland community which rests in the north-central part of the state between Jacksonville and Tampa, has historically been spared the devastation from hurricanes that coastal areas in the state face. However, a series of storms in recent years has led the City of Ocala Electric Utility to coordinate with both FEMA and the Florida Division of Emergency Management on recovery efforts.

Through recent recovery experiences, OEU has developed ongoing relationships with both agencies to improve how it manages financial processing and documentation at the state and federal levels.

OEU staff have found their FEMA counterparts to be knowledgeable and attentive, particularly in providing guidance on the procedures for documenting storm damage and obtaining financial support.

"Hurricane Milton was my first time coordinating with FEMA, and I found them to be very helpful. We had two or three different staffers assigned to us, all of whom were informative, especially since I was still learning how their processes worked," said Catherine Larson, financial operations manager at the City of Ocala.

OEU is one of the smaller municipalities in the state, and staffers have been dedicated to finding ways of streamlining the reimbursement process.

"We've recently been working with the state on the Florida Recovery Obligation Calculation, or F-ROC, program by the Florida Division of Emergency Management to simplify the disaster cost recovery documentation process," Larson said.

OEU staff noted this program would expedite the grants and reimbursement process in ways beneficial to them and other public power utilities that might not have the resources of a larger municipality. Proposed aspects of the program include an early documentation review process that would effectively score and pre-certify organizations so they could receive quicker reimbursement.

"The program supports organizations by streamlining documentation requirements, providing faster access to funding and makes recovery more efficient, by avoiding a lengthy post disaster review process," said Marie Brooks, utilities finance manager at OEU.

"FEMA assistance allows us to prioritize the rapid restoration of services. But eligibility requirements are not always clear."

CHARLENE POLLETTE, FINANCIAL ANALYST,
OCALA ELECTRIC UTILITY, FLORIDA

Another effort would streamline the document preparation process, reducing the burden of paperwork for communities in recovery mode.

"Instead of feeding into an Excel spreadsheet with formulas, [the state is developing forms] that will take in your information and prepare documents that give the actual cost up front. We've seen demonstrations and trainings on it, and it looks like it's going to be very useful to have for the next hurricane," Larson said.

As Ocala staff explained, OEU's financial management and disaster recovery teams possess extensive knowledge of both internal processes and how to recover from hurricanes — expertise that has been honed by managing the local response to seasonal storm activity.

The utility's hope is that FEMA will institute reforms that streamline reimbursement, particularly in developing processes that allow municipalities to know upfront what items are eligible for reimbursement.

"FEMA assistance allows us to prioritize the rapid restoration of services. But eligibility requirements are not always clear. This is where we work closely with FEMA and FDEM to determine eligibility. Their timely communication works great for us," said Charlene Pollette, financial analyst for OEU.

OPPB lineworkers repairing fallen poles. Photo Courtesy Omaha Public Power District.

Stronger from Experience

Omaha, Nebraska, sits in both Tornado Alley and the Missouri River flood zone. This confluence of risk has required employees of the Omaha Public Power District to build broad expertise in disaster response and risk management.

Tonya Ngotel, manager of emergency preparedness for OPPD, came to the utility in 2021 from an extensive career in disaster and emergency response. In the last five years, Ngotel has managed response to some of the most intense natural disasters the utility has faced.

The past two years have proved to be especially demanding for the utility and the city of Omaha.

"In 2024 and 2025, we had six federally declared disasters, two of which were the largest OPPD has ever seen as far as outage and in cost in our 80 years of service," Ngotel said. "Just within those two years, there were multiple disasters, some building atop the others. We've had floods, tornadoes, high winds, and even a little bit of winter weather in there."

Jim Karnik, manager of asset accounting for OPPD, noted that the utility has, on average, experienced a storm-related federal declared disaster every two years. Since 2019, he shared, the OPPD has seen nine declared disasters and activated its storm team on 28 other occasions.

Ngotel noted that the disaster response team's expertise and familiarity have allowed the utility to manage these events efficiently, including coordinating with the mutual aid network and other institutional relationships that OPPD maintains year-round.

"Through preparedness and mitigation efforts, based off FEMA's phases of emergency management, OPPD works with local, state, and federal partners in developing a state of readiness. We've created this emergency operations center concept that's able to support the field teams that are out there, and then able to communicate and coordinate with our state and federal partners," Ngotel said.

"Utilizing the FEMA Public Assistance program allows OPPD to not only recover and repair critical infrastructure, such as poles and lines, after a storm, it also allows opportunities to mitigate future risks by enhancing facilities,"[AP5] added Ngotel. As an example, OPPD was able to mitigate damage to its infrastructure from flooding in 2024 based on the experience and support received during major flooding events in 2011 and 2019.

> **"Utilizing the FEMA Public Assistance program allows OPPD to not only recover and repair critical infrastructure… it also allows opportunities to mitigate future risks."**
>
> **TONYA NGOTEL,** MANAGER OF EMERGENCY PREPAREDNESS, OMAHA PUBLIC POWER DISTRICT, NEBRASKA

Ngotel expressed appreciation for the level of diligence FEMA partners bring to disaster response and recovery efforts.

"FEMA has become a constant presence when the district needs federal support following a major disaster and helps keep the cost of power manageable," said Ngotel.

"[Public Assistance program funding] helps keep our rates more affordable and our structures more resilient," added Karnik.

As FEMA undergoes reform, OPPD hopes the valuable staff and institutional knowledge the agency possesses is retained, so that it is able to maintain the interpersonal relationships that OPPD and other public power utilities have built with their disaster response partners.

"We've encountered challenges with staff turnover and changes at the administrative and regional levels. When you have a lot of staff either leaving or coming on, that can hamper learning opportunities and lead to snags in information retention," Ngotel said.

Karnik noted that clearer guidance for utilities — for example, clarifying the difference between a pole upgrade or needed repair during emergency restoration activities — could also help streamline the public assistance process.

On its end, OPPD has worked to ensure financial reimbursement paperwork is completed in a timely fashion to help make its federal partners' jobs as easy as possible.

Ngotel also recommended that FEMA's federal-level policymakers focus on incorporating the needs and experience of public power utilities, which stand at the forefront of community disaster response and serve over 55 million people in the U.S. and its territories.

"We have an opportunity to educate people. Emergency management is critically important, and emergency management within utilities is even more critical. I believe the opportunity is there, and we haven't necessarily capitalized on that," Ngotel said.

PUBLIC POWER COMMUNITIES
PRAIRIE DU SAC, WISCONSIN

BY ADAM PATTERSON, CONTENT SPECIALIST,
AMERICAN PUBLIC POWER ASSOCIATION

The public power utility that serves Prairie du Sac, Wisconsin, was established in 1914, the same year the Prairie du Sac Dam hydroelectric project was completed. The dam's construction was a rigorous undertaking that required ingenuity in the face of numerous engineering challenges at the time, such as how to handle both the width of the Wisconsin River and the shifting sands in and around the waterway.

The dam remains the largest of the more than 20 hydroelectric installations on the 420-mile river. The dam has held strong since opening, surviving over a century of wear, including the acute stress of the 2008 Midwest floods, to continue providing a wealth of renewable energy to surrounding municipalities.

Troy Murphy, Prairie du Sac's director of public works and a 2025 recipient of the American Public Power Association's Larry Hobart Seven Hats Award, noted that Prairie du Sac's electric department was chartered for reasons common for Midwestern towns at the time — to provide reliable, affordable electricity for a growing municipality whose prosperity depended on it.

"Back in 1914, the community's one privately owned generator was failing to provide the power they needed. So, the village board came together and established a community-owned utility to keep the lights on," Murphy said.

The public power utility remains a centerpiece of the town's economy and civic life. It has sustained the community over many decades and is now supporting its rapid growth.

For generations, Murphy's family managed their farm before Troy and his brothers all grew up to work in the power sector. Murphy worked at a rural electric cooperative before coming to Prairie du Sac's utility, where he built a career that has spanned nearly three decades so far.

"I landed here in 1997. And once you land in public power, I always say it's your fault if you leave, because it's meaningful work — very family- and community-oriented," he said.

Murphy finds that a close relationship with the community ensures responsiveness and a high quality of service, particularly when coordinated through the support provided by WPPI Energy, a joint action agency serving public power utilities in Wisconsin, Iowa, and Michigan.

"If we're getting a storm on a July night, every one of us is watching the news wondering how the other member communities are doing. Next thing you know, I'm getting text messages asking me, 'Are you and your crew set down there? We're ready to send help,'" Murphy said.

He noted this care for neighbors extends to how the utility engages with the Prairie du Sac community, including its focus on helping people stayed informed about electrical safety.

"We have our energy services reps and line crew take bucket trucks down to the school and teach kids about safety around downed power lines and open transformers," Murphy said.

Prairie du Sac's proximity to Wisconsin's growing capital — the town is just 25 miles northwest of Madison — has drawn a wave of new development the utility has been instrumental in supporting. The town has a wealth of publicly managed amenities, including the nearby Great State Trail and a newly formed daycare, that stand alongside the electric department in advancing the community's quality of life.

"There's now a village-owned daycare within the 70-acre Culver Community Park that was recently built and is operated by our school district. People can move here, find affordable housing, and have daycare right across the street. … It's been one of the main drivers of why we've grown 30%–40% in the past decade," Murphy said.

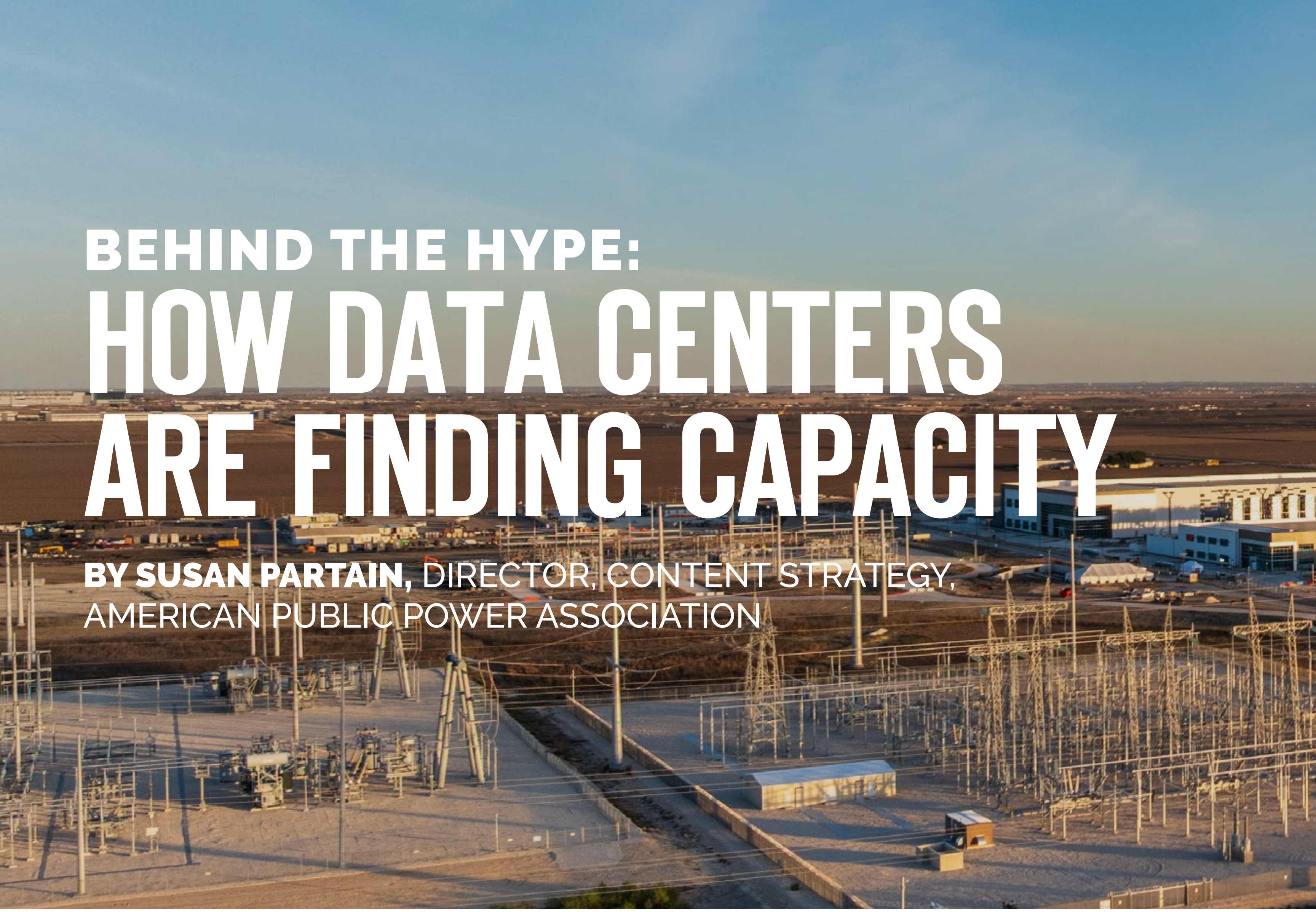
He noted that another housing development is projected to have 450 new electric meters that will provide the kind of reliable, affordable power Prairie du Sac residents enjoy.

Murphy continues to see Prairie du Sac's utility providing that same quality of service for years to come, particularly as work begins on a planned downtown renovation project. The upcoming Water Street reconstruction will be launched with support from the Wisconsin Department of Transportation and will pave the way for the utility to upgrade the town's distribution lines in partnership with American Transmission Company (ATC).

"We have a $20 million project coming through that will involve a total reconstruction of our downtown streets. With that, we're completing upgrades to our electric system, including the rebuilding of distribution feeders and undergrounding of power lines. That's going to offer a lot of redundancy to our high school and downtown area," Murphy said.

He calls the ability to engage directly with the community he serves and watch how his team's work advances Prairie du Sac's quality of life one of the most fulfilling parts of his job.

"That's the beauty of working in public power — seeing how the improvements you work on day in and day out make your town a better place to live," he said.



BEHIND THE HYPE: HOW DATA CENTERS ARE FINDING CAPACITY

BY SUSAN PARTAIN, DIRECTOR, CONTENT STRATEGY, AMERICAN PUBLIC POWER ASSOCIATION

The hubbub about data centers — and their growing appetite for electricity — comes with concerns ranging from how much energy they will use to how that use will affect energy affordability, the environment, and grid reliability.

Amid this uncertainty, public power utilities are exploring how to navigate the potential for new data center load, and how to best support ongoing affordability and reliability for the communities they serve.

No Clear Forecast

While there seems to be consensus that electric demand from data centers will grow, estimates about how much capacity they will need, and how much current capacity can cover this growth, vary widely. There are also growing concerns about "phantom load" – or duplicate requests from data center developers that are inflating projections well beyond what will be required.

The Energy Information Administration's December 2025 Short Term Energy Outlook forecast electricity sales to increase by 2.4% to the commercial sector and 1.6% to the industrial sector in 2026, and continue growing further in 2027, with additional sales increases of 4.3% for commercial customers and 3.4% for industrial end users. The EIA noted that "this increase can be largely attributed to increasing demand from large computing facilities, that include data centers."

A July 2025 report from the Department of Energy estimated that the U.S. electric grid will need to support 50 GW additional peak load by 2030 due to data center growth alone.

A January 2026 California Energy Commission presentation predicts that data centers' contribution to peak load in the state will exceed 4.7 gigawatts, or about 20% of overall peak load through 2045. The projections are largely based on assumptions from planners at investor-owned utilities in the state, and while some estimates were scaled back from those released earlier in 2025, the commission acknowledged that this load could be even higher, and that there are gaps in planning amid uncertainty about data center load.

The American Public Power Association's October 2025 report, *What Public Power Needs to Know About Serving Data Centers,* includes a comparison of estimates for data center growth that have a wide range of projected capacity needs, from 50 gigawatts (S&P Global Market Intelligence) to well over 120 GW (Deloitte and Lawrence Berkeley National Laboratory).

Underpinning the question of capacity is how much demand data centers need, and whether the computing demand driving data center development is justified. Data center load is driven by consumer demand and the promise that transactions which drive our increasingly digital lives remain available at all hours of the day.

"Our lives are consumed with digital [activities]. We're not going to go back to depositing paychecks at the bank anytime soon," said Nur Bernhardt, vice president at Cloverleaf, a firm that works with utilities to develop data center sites.

At a presentation during APPA's Customer Connections Conference, Bernhardt shared that data center customers' capacity needs ramp up over time, and that the largest developers are seeking hundreds of megawatts to more than a gigawatt per site. In terms of overall use, U.S. data centers could use 400 terawatt-hours annually by 2030, according to Bernhardt's presentation. That includes about 300 TWh used by "traditional" data centers, and 100 TWh for those fueling artificial intelligence.

Daily Requests

Texas has emerged as a center of growth for large loads. The Electric Reliability Council of Texas noted that it has about 225 gigawatts in its interconnection queue from large loads, and about three-fourths of that capacity is for data centers. The total capacity requests from large loads grew 270% in 2025 and now comprise over half of ERCOT's interconnection requests.

Austin Energy, the public power utility serving the capital, said it receives continual inquiries about potential large load projects.

"Companies seem to be especially focused on exploring locations in Texas, which makes it a top priority for ERCOT and for utilities across the state, including Austin Energy. The inquiries are truly unprecedented and require work in areas many utilities have never really had to deal with before," said Stuart Reilly, Austin Energy's general manager.

Reilly said Austin Energy is in need of more local generation to support growing demand, regardless of data center inquiries.

"Because electricity demand is the common thread in all these conversations, other large load customers don't differ much from a data center inquiry to other developments. However, there can be more uncertainty about whether data centers will come to fruition and where they will locate," Reilly said.

"Our prime considerations continue to be safeguarding reliability and affordability for our community while appreciating that data centers create opportunities for revenue and economic opportunities for our city," said Reilly. "We want to contribute to economic growth without creating negative impacts to our community. We need to be mindful of electricity needs, water use, land use, and community concerns about the local impact."

Austin Energy said it talks about the challenges and opportunities related to data centers with its oversight committees, including its city council.

"We are very hands-on with all new large customers, as we hope to have a lasting partnership in our community. Since that relationship is built on trust, we're very up-front about interconnection study requirements and supply chain wait times," added Reilly.

What's Valuable

A McKinsey & Company article in August 2025 expects companies to invest more than $2.68 trillion in the U.S. into data centers through 2030. While most of these costs are for servers and other equipment, about 6%, or $160 billion, would go toward power generation.

Bernhardt noted how the period of load growth coincides with a shift in how grid operators are looking at generation capacity and resource adequacy.

"Utilities are seeing the first significant load growth in decades, while dealing with a transition from legacy fossil fuel generation to intermittent renewable generation. In the past, utilities matched their generation capacity to meet their peak load. Now, utilities are having to shift their approach," said Bernhardt.

Bernhardt noted that data center customers are willing to provide financial commitment to reduce the risk of stranded assets while building new capacity to help serve the load. That approach requires a strong partnership between utilities, local stakeholders, and the data center.

"The approach that has worked well is for the data center to provide a deposit and financial security early in the process to allow the utilities to increase staffing, conduct engineering studies, and secure production slots for the long lead equipment. The goal is to demonstrate to our utility partners that they are spending time with a committed customer," he said.

"While we focus on energy first, energy is not everything that we need to develop a site. Land control, completed due diligence, and zoning are all important steps in the process before we can make significant financial commitments."

"Given the rapid growth of data centers and the increase in demand for electricity that goes with them, we think it is important to require new customers to pay for equipment upfront to protect our other utility customers from those costs," said Reilly. Bernhardt cautioned that significant prepayment or minimum requirements might signal to prospective data center customers that an area isn't going to be supportive.

"Data centers are not going to be everywhere, and they definitely won't go where they aren't wanted," said Bernhardt. "Data center companies will invest $10-15 million per megawatt to build their facilities and connect them to the fiber network. Costs can go up fast, so they are looking for a location where they can operate for the next 20-30 years. If the jurisdiction isn't supportive, they aren't going to get them."

As an example of what attracts data centers, Bernhardt mentioned a project with Grand River Dam Authority in Oklahoma, within the Southwest Power Pool market, which has what he called a "transparent, clear way" for large load customers to supplement a utility's capacity through a supplemental supply rider, which allows them to meet resource adequacy requirements without additional financial risk to existing customers.

"A 'Bring Your Own Capacity' approach is a modern update to an old playbook. Before wholesale power markets existed, large manufacturers would negotiate their own power commitments that would be sleeved through their local utility," he said. But, those arrangements fell out of fashion when load growth was declining.

Bernhardt also noted that communities that can offer a sales tax exemption for servers will be attractive to developers, as those comprise a high proportion of their reoccurring capital costs.

Economic Considerations

A report from Monitoring Analytics, the market monitor for PJM, said that existing and forecasted data center demand was responsible for nearly $6.5 billion in increased costs in the capacity market for 2027-2028, and that “data center loads are the source of the reliability issues” in the regional transmission organization.

These types of costs raise concern, but utilities and developers see potential for data centers to offset costs, too.

Bernhardt pointed to a report from the Urban Land Institute, Local Guidelines for Data Center Development, that can be helpful for communities wanting to understand more about the data center model and the “good and bad ways” to develop data centers.

“At the local level, it’s hard to predict what a national industry will do over time,” said Bernhardt. He advised that utilities hearing from developers check the finances and familiarity of the companies looking to invest in the community. “Pick the one with the best balance sheet and the most experience. It’s important that to make sure they have an understanding of the industry’s requirements.”

He advised against being the first partner for a developer, as it’s also helpful for data centers to understand the challenges utilities face in taking on such projects.

Bernhardt advised utilities to take a step back and see whether welcoming a data center would be a good business decision for the community.

> **“At the end of the day, do you want to raise rates on your current customer base, or seek out a new large customer that’s going to work with you?”**
>
> **NUR BERNHARDT,**
> VICE PRESIDENT
> CLOVERLEAF

If a utility needs to replace an aging or fully deprecated generating plant, or is in the middle of transitioning its mix to cleaner, more intermittent sources, it might have more incentive to find a large load customer to offset the cost of developing new capacity.

“At the end of the day, do you want to raise rates on your current customer base, or seek out a new large customer that’s going to work with you? It’s important to make sure the incremental costs are allocated transparently and won’t impact the general the rate base,” he said.

Finding Flexibility

The Public Utility District for Lewis County, in Washington state, serves not only a growing population, but has been working to accommodate large load customers in its area, including data centers that serve cryptocurrency mining.

Part of its goal, said David Plotz, the PUD’s general manager, is to take control of its future state with a handful of projects to increase its own generating capacity. Plotz said on the Public Power Now podcast that projects being explored include small hydroelectric, pumped storage, and geothermal.

Plotz said that utilities up to now have been “essentially following load, building as need arose,” and that they should now be turning their attention to building ahead of growth.

“Throughout history, we’ve built new projects with the idea that the load will arrive. But until that load arrives, existing ratepayers subsidize that newly constructed project. So very good planning was always necessary, and it still is today. But the idea that you can predictably bring in Bitcoin mining right at the point of energization means there’s no more cross-subsidization. In fact, it makes it even more clear that you can say historical preference rates off the federal system can be reserved for [existing] customers, and, for the newly arriving loads, you can be very specific that these new projects are now being used to deliver the energy to them,” said Plotz.

“As we move into a more connected and technologically complex grid, demand management is becoming a larger aspect of delivering additional capacity to existing load and/or newly arriving load,” he added. Plotz noted that Bitcoin miners have already shown a willingness to be part of demand management

> **"As we move into a more connected and technologically complex grid, demand management is becoming a larger aspect of delivering additional capacity to existing load and/or newly arriving load."**
>
> **DAVID PLOTZ,** GENERAL MANAGER, PUBLIC UTILITY DISTRICT OF LEWIS COUNTY, WASHINGTON

efforts, such as by building in curtailment during peak periods into their contracts.

While Bitcoin miners offer this flexibility, said Plotz, utilities shouldn't expect the same from other data center customers. "Cloud storage can probably shut off just about as quickly, but you don't want a situation where you cannot access your files," he said.

Locating large load customers closer to generation sources can also offer savings, said Plotz, as it would mean reducing the need to build additional transmission infrastructure.

While the PUD has had inquiries from other types of data center load, Plotz said the scale and timing of what some customers need doesn't align with what the PUD can offer.

"These data centers want a gigawatt and they want it yesterday. We don't have a gigawatt of spare capacity — our utility only operates around 125 average megawatts," he said, adding that transmission congestion is a major issue in the area. "Even if we could get the [capacity], getting it here is the harder part."

Plotz recognized that data center development is not as robust in the Pacific Northwest as other parts of the country, due to transmission congestion and capacity constraints stemming from Washington's goal to transition to a carbon-free generation mix by 2045.

"If we want to grow or if we want to have those jobs, we need to be a lot more proactive and more unified in the region," he added.

Public Power Leaders: **Tom Barry**

Tom Barry was appointed CEO of Massachusetts Municipal Wholesale Electric Company in September 2025. He joined the joint action agency as director of energy markets in 2024. Barry's expertise in the power sector has encompassed energy and environmental portfolio management alongside commercial optimization, operational management, organizational strategy, and risk management. He previously served as vice president at American Electric Power and held positions in wholesale power trading, derivative products origination, and finance at Phibro Energy.

The following is adapted from an episode of the Public Power Now podcast.

WHAT HAVE BEEN YOUR PRIORITIES SINCE BECOMING CEO OF MMWEC?

Taking over for Ron DeCurzio, who was the CEO for over 18 years, is a big undertaking. I'm humbled by the new responsibility but also excited. I believe the model that we have is the right model. I believe in the people I work with. I've inherited the best of the best, and my future success is directly tied to their success.

I'm focused on a seamless transition for the municipal light plants (MLPs) that we serve and want to ensure we continue to build and improve on the services we provide. Before I moved into this new role, it was my goal as director of energy markets to meet face to face with people — both the general managers that we work with and the general managers of future members — and share our mission and model with them.

Something I'm focused on is changing our internal culture a bit. I want our staff to feel more empowered to have an entrepreneurial spirit. On my first official day, I brought the entire company into my office to discuss shifting the culture.

WHAT KIND OF SERVICES DOES MMWEC OFFER MEMBER UTILITIES?

The first and foremost is power supply. With the municipal light plants that we work, 80% of their costs are based on energy costs. So, our services as a joint action agency on the power supply front are paramount. We've made lots of changes on that front just within the two years I've been here.

On the hedging side, we've restructured it and made it more disciplined. We've incorporated more of a dollar cost-averaging approach than we had in the past, in that every single month on the 15th we go out and take a small bite of the apple for each MLP we represent.

> **"I'm a big advocate for diversity and energy independence and want to be part of bringing more generation into the region."**

What's great about that is we have a wide range of municipal light plants within our system. As a joint action agency, we have this ability to do aggregated purchasing so smaller MLPs within our group can have the buying power of the larger MLPs. It really speaks to what joint action is all about.

Our resource development is exceptional as well. Based on our charter and the way we're structured, we have unique financing abilities that allow us to explore new generation opportunities on behalf of our members. Our ability to raise capital toward that is of great importance to those we serve.

COULD YOU DESCRIBE THE CONNECTED HOMES PROGRAM AND HOW YOUR MEMBER UTILITIES BENEFIT FROM IT?

Connected Homes is part of our NextZero program and an integral part of our business. We work with 2,000 different homes, and within those we work with 3,000 different devices. Those devices range from thermostats to electric vehicle chargers, residential batteries, mini-splits, and hot water heaters. We now manage 7 megawatts of peak load through our Connected Homes program.

Our ability to manage those devices to mitigate peak load has been especially helpful considering the levels that transmission and capacity charges have been at recently. We're focused on mitigating those costs for our member utilities, and Connected Homes has been an effective way of doing so. I like that it's both an automated and a flexible system. There's optionality built into our Connected Homes program that allows customers to not lose control of what they want within their own home.

WHAT ARE YOUR GOALS FOR MMWEC GOING FORWARD?

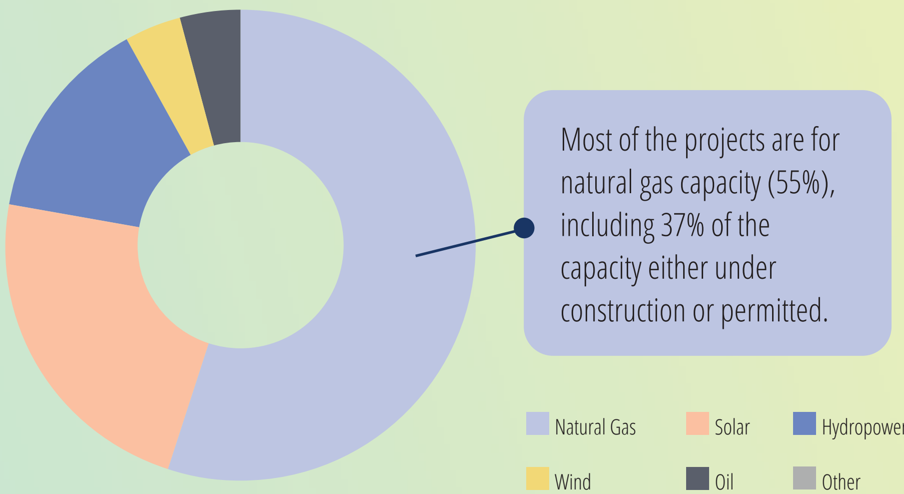
I'd like to explore expanding our footprint. There are 40 MLPs within the state of Massachusetts, and I'd like to pursue looking into other loads within the state that are traditional investor-owned utility loads. I feel that public power is the right model when it comes to supplying power.

New England is unique. We've been fortunate in the past to have lots of power coming south from Canada and we'll continue to have that. But that has been less available than it has in the past, so I'm a big advocate for diversity and energy independence and want to be part of bringing more generation into the region. I'd like to see more natural gas generation in the region, and in the longer term I'd like to be part of exploring nuclear generation as well.

More than anything, I'm excited to work with the staff we have here. We've got amazing people who are all doing great things for a great cause.

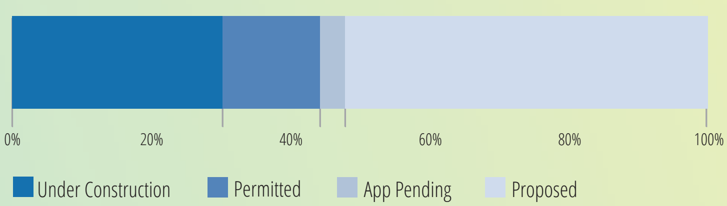
What's in Public Power's Pipeline?

At the end of 2025, there were **8,867 megawatts** of generating capacity in some stage of development attributed to public power entities – a 7% increase over the capacity in development at the end of 2024.



The capacity total doesn't include storage assets under development, of which there are about 20 projects across the U.S.

Most capacity is still in the early stages of development (4,945 MW). Nearly 88% of solar capacity under development is in the "proposed" stage.



Projects under construction include: