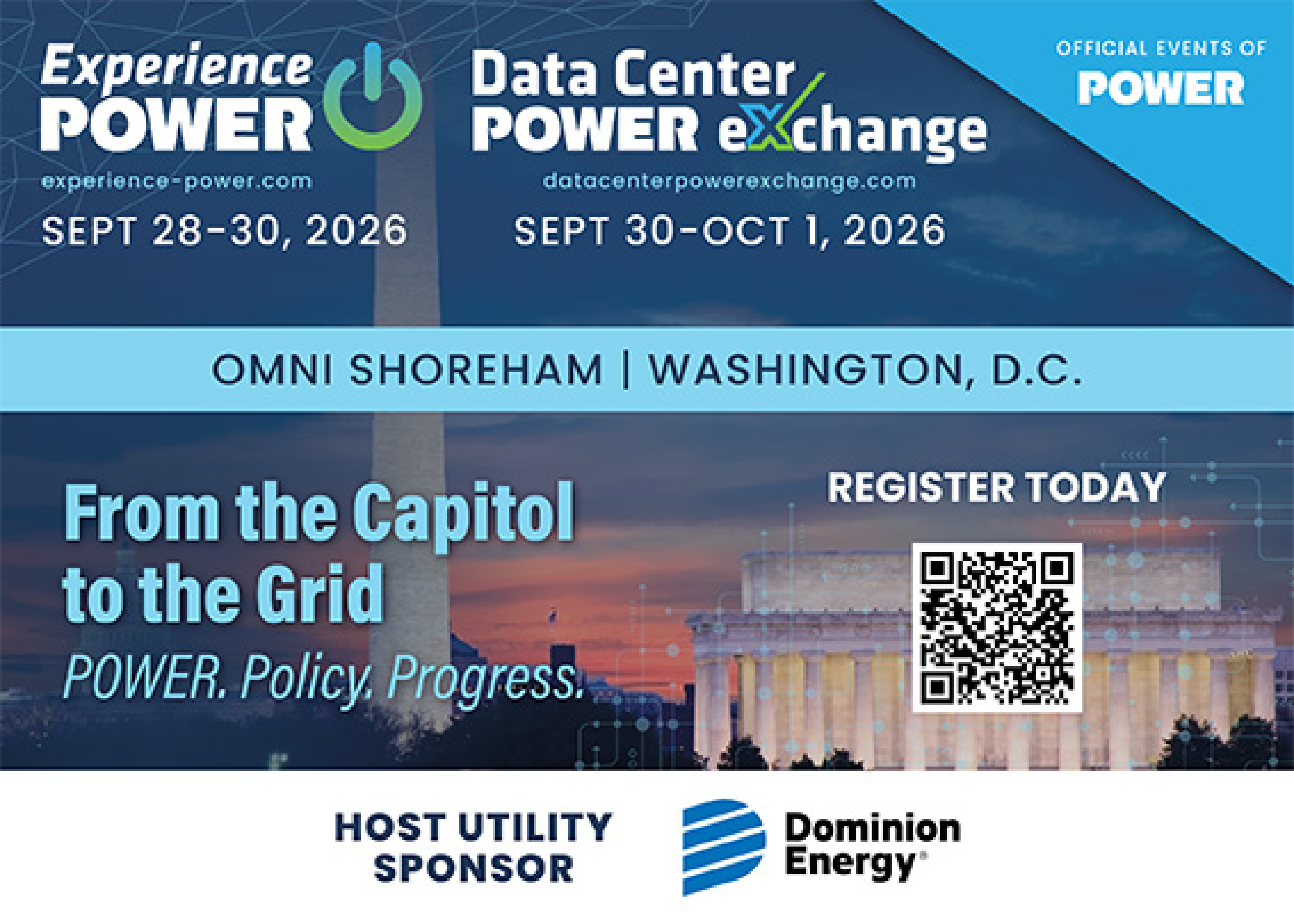
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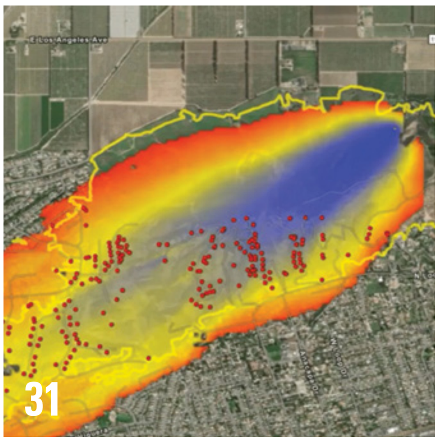
ON THE COVER

The calm before the storm. There's no better time to prepare for severe weather than before storm season arrives. Being ready can mean the difference between lights on and lights off. *Source: wirestock / Envato Elements*



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NEWS & TECHNOLOGY FOR THE GLOBAL ENERGY INDUSTRY SINCE 1882

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POWER (ISSN 0032-5929) is published monthly, 9 times print and digital, 3 times digital only, by Access Intelligence, LLC, 9211 Corporate Blvd., 4th Floor, Rockville, MD 20850-3245. Periodicals Postage Paid at Rockville, MD 20850-4024 and at additional mailing offices.

Postmaster: Send address changes to POWER, 9211 Corporate Blvd., 4th Floor, Rockville, MD 20850. Phone: 800-777-5006, Fax: 301-309-3847, email: clientservices@accessintel.com.

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The Heat Is On: Summer Safety for Power Crews

Aaron Larson

Summer is the season utilities brace for. Demand peaks as air conditioners run flat out, equipment runs hot, and the workforce that keeps the grid alive does so under some of the year's most punishing conditions. The same months that strain transformers and conductors also strain the people climbing structures and pulling cable beneath them. For power professionals, warm-weather preparedness is not a seasonal courtesy — it is a core safety discipline. Three hazards in particular deserve a fresh look before the mercury climbs: heat stress, lightning, and the chaos of severe-storm restoration.

Heat Stress: The Slow-Building Emergency

Heat illness rarely announces itself. It builds quietly across a shift until a worker who felt fine an hour ago is suddenly confused, cramping, or collapsing. For line and field crews, the risk is compounded by factors most workers never face: arc-rated clothing and flame-resistant layers that trap body heat, climbing exertion that drives core temperature up fast, and elevated or confined work positions where a dizzy spell becomes a fall hazard.

The progression matters. Heat cramps and heavy sweating are early warnings. Heat exhaustion—clammy skin, nausea, weakness, headache—signals the body losing its battle to cool itself. Heat stroke, marked by confusion, hot dry skin, and loss of consciousness, is a life-threatening emergency that demands immediate cooling and a 911 call. Crews should treat any worker who stops sweating in extreme heat as a red flag, not a sign of recovery.

Prevention is straightforward but requires discipline. Acclimatization is the most overlooked safeguard. New workers and those returning from time off need a gradual ramp-up over several days, because the body adapts to heat far more slowly than supervisors assume. Hydration should start before the shift and continue in small, frequent amounts rather than in occasional large gulps. Schedule the heaviest work for the morning, build in rest breaks in shade or air conditioning, and use the buddy system so someone is always watching for the early signs a struggling worker may not recognize in themselves.

There is still no federal heat standard. OSHA's proposed heat-illness rule has stalled with no finalization date, so the agency enforces through its General Duty Clause and a national emphasis program it revised in April 2026—while a number of states maintain their own heat rules. A written heat illness prevention plan remains a smart safeguard regardless of where federal rulemaking lands.

Lightning: Thirty Seconds to Decide

Summer thunderstorms develop fast, and for crews working aloft or handling conductors, lightning is among the most unforgiving hazards out there. The danger zone extends well beyond the storm itself. Lightning routinely strikes miles ahead of visible rain, which is why the "30/30 rule" remains the field standard: when the time between a flash and its thunder drops to 30 seconds, the storm is close enough to be dangerous, and work should stop. Crews should not resume for at least 30 minutes after the last thunder.

That guidance only works if someone is responsible for watching the sky. Assign storm-spotting duty before work begins, and pair it with a real-time weather alerting tool so crews are not relying on a passing glance at the horizon. Bucket trucks, elevated platforms, and steel structures all turn workers into the high point of the landscape—exactly where lightning seeks ground. The safest refuges are a fully enclosed vehicle or a substantial building, not a shed, not a bucket, and never the partial shelter of an overhead structure. The instinct to finish "just one more connection" before retreating has killed experienced linemen. The rule has to override the schedule.

Severe Storms and the Restoration Scramble

When summer storms move through, the work shifts from routine to restoration, and the risk profile changes with it. Outage response concentrates the industry's most dangerous conditions into a compressed, high-pressure window: downed conductors that may still be energized, damaged poles and crossarms under unpredictable load, debris-strewn footing, and crews running on adrenaline and too little sleep.

Fatigue is the quiet driver of restoration incidents. As outages stretch into long shifts and back-to-back days, judgment erodes and reaction time slows precisely when the hazards are greatest. Managing rotations, enforcing rest, and resisting the pressure to push crews past safe limits are safety functions, not logistical afterthoughts. Every downed line should be treated as energized until tested and grounded, and crews must stay alert to backfeed from customer-owned generators—improperly connected portable units can re-energize a "dead" line and endanger anyone working it. Mutual-aid crews arriving from other utilities add another layer of risk: unfamiliar territory, different equipment standards, and crews who have not worked together before. Clear briefings and consistent grounding practices keep that coordination from becoming a hazard of its own.

Preparedness Before the Season

The common thread across all three hazards is that the response cannot be improvised in the moment. Heat plans, storm-spotting assignments, hydration supplies, weather-alerting tools, and restoration protocols all need to be in place and rehearsed before the first heat wave or thunderstorm tests them. Toolbox talks in late spring are the ideal moment to refresh crews on warning signs and stop-work authority—and to make clear that any worker can halt a job over a weather concern without second-guessing.

Summer will push the grid and the people who run it to their limits. The utilities that come through it safely are the ones that prepared for the season before it arrived. ■

*—**Aaron Larson** is POWER's executive editor.*

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How the Power Sector Is Bracing for a More Violent Climate

Courtesy: imagesourcecurated / Envato Elements

Utilities, federal agencies, and the national labs have finally assembled the tools to harden the grid against an increasingly hostile environment. The question is whether they can put them together fast enough.

Aaron Larson

When a line of storms tore across the Northeast in late April 2025, racing from Ohio into central Pennsylvania, meteorologists recognized the signature instantly: a bow echo, the curved radar shape that betrays a wall of straight-line winds strong enough to flatten trees and snap power poles for hundreds of miles. To the utilities in its path, it was something more specific—another entry in a ledger that has been growing alarmingly long. Extreme weather is no longer an occasional stress test for the American power grid. It has become the defining engineering and planning challenge of the decade.

The numbers explain why. According to the Electric Power Research Institute (EPRI), the U.S. logged roughly 70 confirmed weather and climate disasters in just three years, each one causing more than a billion dollars in losses—a sharp acceleration over previous decades. Heat waves now arrive earlier and last longer. Winter storms reach further south than the grid was built to withstand, as Texas learned in catastrophic fashion in 2021. Wildfires threaten transmission corridors across the West, and hurricanes batter the Gulf and Southeast with intensifying force. Each hazard attacks the grid differently, but the cumulative message is the same: a system designed for a stable climate now operates in an unstable one.

1. A storm front advances over power lines in a rural area. Worsening extreme weather is driving billions in federal investment to harden the grid. Courtesy: ashleyhallphotonnk / Envato Elements

A Framework for Measuring the Unmeasurable

For years, the central difficulty was not awareness of the threat but the absence of a shared method for quantifying it. Utilities knew extreme weather was worsening; they lacked a rigorous, standardized way to translate that knowledge into investment decisions. In May 2025, EPRI moved to close that gap with the release of its Climate READi: Power Framework, the product of more than three years of collaboration.

The scale of the effort signals how seriously the industry now takes the problem. EPRI assembled more than 40 utilities alongside over 100 academic institutions, consulting firms, finance organizations, national laboratories, regulators, and government bodies to build the framework. The initiative—short for the Climate Resilience and Adaptation Initiative—set out to give the power sector a common language for physical climate risk, covering how to plan, design, and operate a grid that can absorb shocks rather than simply break under them.

What distinguishes Climate READi from earlier resilience guidance is its integrated approach to planning. Rather than treating climate as a separate variable bolted onto traditional models, the framework's modeling component weighs climate impacts alongside the other forces reshaping the grid at the same time: surging electricity demand, the transition toward decarbonized generation, and persistent regulatory uncertainty. That matters because these pressures interact. A heat wave that spikes air-conditioning demand also degrades the transmission lines carrying that power, and it does so just as the grid leans more heavily on weather-dependent solar and wind. Planning for any one of these factors in isolation produces a dangerously incomplete picture.

EPRI's leadership has framed the work as foundational rather than optional. President and CEO Arshad Mansoor has called extreme weather and climate "urgent problems," positioning the framework as a set of tools for addressing current and future risks while keeping energy reliable and affordable. Utility executives involved in the project have echoed that, describing grid hardening against extreme weather as one of the sector's defining challenges for years to come and praising the framework's data-driven, science-based design as a way to make smarter investment decisions. EPRI has made the framework publicly available, and its distribution research arm maintains a parallel body of work focused specifically on wildfire and extreme-weather threats to local power lines, including seasonal readiness guides and vegetation-management studies.

Federal Dollars Follow the Risk

If EPRI supplies the analytical scaffolding, the U.S. Department of Energy (DOE) has supplied much of the money. The centerpiece is the Grid Resilience and Innovation Partnerships program, known as GRIP, which channels federal investment into modernizing transmission and distribution (T&D) infrastructure against extreme weather and natural disasters (Figure 1).

The sums are substantial. In October 2023, the DOE announced up to $3.46 billion in GRIP Program investments "to strengthen electric grid resilience and reliability across America," which included projects selected under Grid Resilience Utility and Industry Grants. The following October, the DOE announced about $4.2 billion in federal investments intended to "protect the U.S. power grid against growing threats of extreme weather, lower electricity costs for America, and increase grid capacity to meet load growth stemming from an increase in manufacturing, data centers, and expanding artificial intelligence and cloud-ready approaches."

In March this year, a third funding opportunity was announced. At that time, the DOE said approximately $1.9 billion was being made available "to catalyze electricity infrastructure investments to meet electricity demand growth and resource adequacy requirements, while reducing costs for American households and businesses." This funding opportunity was renamed "Speed to Power through Accelerated Reconductoring and other Key Advanced Transmission Technology Upgrades (SPARK)" to provide clarity with the program's updated emphasis, the DOE said. The application deadline has passed. Awards are expected to be made sometime between October 2026 and January 2027.

Behind the grants sits a broader vision. The DOE's 2024 Grid Modernization Strategy frames the challenge across six dimensions—reliability, resilience, security, affordability, flexibility, and environmental sustainability—and names climate resilience as a core objective rather than an afterthought. The logic is that climate stress touches every one of those dimensions. Extreme heat degrades conductors and transformers; flooding can knock out substations; wildfire smoke can trip protective relays; and shifting wind and temperature patterns alter the load the grid must serve. A strategy that improves one dimension while ignoring climate exposure could undermine the others.

More recently, the DOE has turned to assessing the system's overall health. An October 2025 federal report evaluating U.S. grid reliability and security drew on analysis from the national laboratories and reliability data from the North American Electric Reliability Corporation (NERC), reflecting a federal effort to take stock of where the grid stands as demand climbs and weather intensifies simultaneously.

The Laboratories Doing the Science

Much of the technical heavy lifting happens at the DOE's national laboratories, where researchers convert climate science into the models and methods utilities and planners can actually use.

The National Laboratory of the Rockies (NLR, formerly known as the National Renewable Energy Laboratory [NREL]) has spent more than a decade helping communities rebuild and strengthen their energy systems after disasters. In research published in January 2025, NLR emphasized that as extreme weather grows more frequent and destructive, communities face mounting demands to secure their energy supply—and that there is no single template for doing so, because each community's vulnerabilities and needs are distinct. That community-level focus complements the utility-scale planning tools coming out of EPRI, addressing the reality that resilience is experienced locally even when it is engineered system-wide. NLR has also developed methodologies for measuring and valuing resilience in energy systems, an attempt to put hard numbers on a quality that has long resisted quantification.

At Pacific Northwest National Laboratory (PNNL), researchers situate grid resilience within a broader national-security frame. PNNL's work translates energy-transition and climate science into strategies that integrate security, sustainability, and resilience, modeling the intricate interactions between Earth systems and energy infrastructure. The lab treats a fragile grid not merely as an engineering concern but as a potential source of geopolitical and socioeconomic instability—a reminder that keeping the lights on during a heat dome or an ice storm is, ultimately, a matter of national resilience.

The Gap Between Intention and Execution

For all the frameworks, funding, and research, independent oversight suggests the federal response remains incomplete. The Government Accountability Office (GAO) has found that while the DOE has identified climate change as a risk to energy infrastructure, the department has lacked an overarching, department-wide strategy to guide and coordinate its resilience efforts. The GAO recommended that the DOE develop such a strategy and that the Federal Energy Regulatory Commission (FERC) systematically assess and plan for climate risks to the grid—pointing out that without clear goals linked to a coherent strategy, federal efforts risk being fragmented and difficult to measure.

That critique is worth holding alongside the optimistic announcements. A multibillion-dollar grant program and a comprehensive risk framework are meaningful, but they do not by themselves guarantee a coordinated national posture. The hazards are accelerating faster than institutions tend to move, and funding levels and program priorities can shift with political and budgetary cycles, leaving long-term planning exposed to short-term uncertainty.

The Pieces Exist—Some Assembly Required

The trajectory is clear even if the outcome is not. Electricity demand is climbing—driven by data centers, electrified transportation, and a hotter climate that pushes cooling loads to record highs—at the very moment the weather is growing more hostile to the infrastructure that delivers it. Federal regulators have warned that peak demand growth is outpacing recent years, and grid operators are revising their forecasting methods and reforming power markets in response.

The encouraging development is that the pieces of a serious response now exist in a way they did not a few years ago: a rigorous industry framework for quantifying climate risk, billions in targeted federal investment, and a national laboratory system steadily producing the underlying science. The open question is whether they can be knit together fast enough, and coherently enough, to stay ahead of a climate that is no longer waiting. The bow echo that crossed Pennsylvania was a single storm on a single spring day. The grid's real test is the decade of storms still to come. ■

*—**Aaron Larson** is POWER's executive editor.*

Backup Power's Shift From Insurance Policy to Grid Asset

For ages, diesel generators have sat behind hospitals and on campuses waiting to do one job: provide power for a few hours each year when the lights inexplicably go out. Today, the narrative is changing—and fast.

Aaron Larson

When U.S. Secretary of Energy Chris Wright wrote to the nation's grid operators on Jan. 22, 2026, asking them to be ready to tap backup generation at data centers and major facilities ahead of Winter Storm Fern, his letter put a number on something the power industry had been circling for years: more than 35 GW of unused backup generation sitting idle across the country, available—if the rules and the wires would let it move. Wright's draft order, developed under Section 202(c) of the Federal Power Act, would reach auxiliary, standby, directly connected, and battery storage systems "regardless of whether they are synchronized to the bulk system," to be called on after demand response is exhausted and before a reliability coordinator declares an Energy Emergency Alert Level 3.

That is a remarkable sentence. Backup power, historically the most passive asset class on the grid, is being asked to step up as a system resource—not in some future energy landscape, but on a Thursday in January, with a storm coming. Talk to the people who actually sell and integrate this equipment, and Fern looks less like a one-off than a milestone on a curve they have been watching bend for years.

1. Six Cat DG150 gas generators provide reliable backup power for a state-of-the-art life sciences hub. Courtesy: Cat Electric Power

The Customer Conversation Has Changed

David Stutzman, a Cat Electric Power territory manager, said the question buyers ask now is not the question they asked five years ago. "Our customers are increasingly interested in the opportunities for monetizing their power assets through using a distributed energy resource management system [DERMS]," he told *POWER*. "When they aren't using an asset for emergency back up power—which may happen two to four times a year—they can use the asset for additional savings and income by participating in utility energy programs."

Two technical shifts have made that pivot practical. The first is fuel. "Natural gas generator sets are becoming more popular due to their flexibility and lowering GHG [greenhouse gas] emissions compared to diesel," Stutzman explained. "Gas gensets tend to have more ratings like demand response compared to diesel, which means customers can take advantage of energy programs." The second is performance: gas units have closed the gap on diesel. Stutzman noted, "Gas generator sets have improved their transient and start-up performance, which are now in line with diesel performance, meaning there is minimal compromise—in terms of engine performance—when choosing gas."

Where is the demand coming from? The obvious answer is the obvious answer. "We're seeing the greatest surge in demand for backup power coming from large multi-unit deployments to support data centers and AI [artificial intelligence] applications," Stutzman said. The less obvious answer is what should interest anyone who watches the broader grid. "We are also seeing increased demand from rapidly growing sectors like supermarkets, retail, and laboratories [Figure 1], driven by rising energy prices and grid instability." Backup power, in other words, is graduating out of the hospital basement and into the strip mall.

Stutzman noted that backup power has "always been essential" for facilities requiring uninterrupted power, which includes data centers, healthcare clinics, retirement homes, and wastewater treatment plants, but that list is being extended to many other industries today. "We are seeing increasing demand from supermarkets, retail buildings, laboratories, and hotels who are recognizing the need for backup power, prompted by more frequent power outages and the necessity to maintain operations such as refrigeration and payment systems."

Battery, Fuel, and the Bridge-to-Grid

If the commercial story is monetization, the engineering story is integration: how batteries, alternative fuels, and engines fit on the same pad and answer to the same controller.

Holly Gregory, a Cat Electric Power se-

2. *Cat XES60 mobile battery energy storage system. Courtesy: Cat Electric Power*

nior product consultant, frames batteries less as a backup source than as a flexibility layer (Figure 2). "Battery energy storage holds more value when used as more than a backup source of power," she said. "It can help offer the flexibility for using alternative fuels in various applications, whether off grid or grid tied." Storage, in her telling, can do three different jobs depending on the day: "generate power to substitute for grid supply, support the grid supply as required, or act as a bridge-to-grid solution to deliver power until a connection to the grid can be made."

That last role—bridge to grid—is increasingly the one that matters in the AI buildout, where utility interconnection queues are years long. As Gregory put it: "Since AI infrastructure buildouts are often power-constrained, time-to-power is critical. In many cases, hybrid DER building blocks and smaller modular generator sets are more readily available than single, very large generator sets. They're also typically easier to transport, stage, and install, helping projects move faster from delivery to commissioning."

Alternative fuels, such as hydrotreated vegetable oil, renewable natural gas, and hydrogen, sit alongside batteries in this picture rather than competing with engines. They can be, Gregory said, "a complementary technology to generator sets and battery energy storage during extended outages, as a strategy for lowering GHG emissions, and to improve site economics."

The piece that ties the rest together is controls. "With strong site controls, microgrids can add capacity in increments and provide tuning for dynamic load profiles by integrating hybrid, flexible DERs such as solar PV, battery energy storage, and smaller modular generator sets," Gregory said. The controller is what turns a yard full of equipment into a single dispatchable thing—synchronizing assets, sharing load, and adding or dropping it on demand to hit whatever objective the operator sets, such as improving fuel efficiency or lowering GHG emissions.

What Facility Managers Get Wrong

Ask Gregory where buyers most often go astray and the answer is not technical—it is procedural. The biggest failure mode is signing up for the wrong cost structure. "When evaluating potential solutions, one major consideration is capital expenditure versus operational expense. While one solution may have more attractive upfront costs, an alternate solution may be as good if not better over the lifetime of the system," she noted.

The second failure is sizing without fully understanding the requirements. "Right-sizing is stronger when the solution is based on an understood load profile and priorities rather than nameplate sizing alone," Gregory said. Meanwhile, customizing a system offers optionality. "A hybrid DER microgrid can give facility managers more operating flexibility since the controller can be configured for different site objectives and operating modes. A manager may wish to prioritize reliability over operating in fuel-saving 'economy' mode."

It is a quiet point, but a significant one: the same hardware can play different roles in different weeks, and the value of that ability compounds over a 20-year asset life.

A Northeast Foodbank's 3-MW Microgrid

The shift from passive insurance to active asset is easier to see in a single project than in a industry study. Stutzman pointed to a large nonprofit foodbank in the Northeast that, after watching demand triple during COVID and grow another 46% over a recent three-year period, broke ground on a centralized 74-acre campus—roughly 77,000 square feet of warehouse, a 47,000-square-foot commissary, a commercial kitchen, and dedicated repack clean rooms.

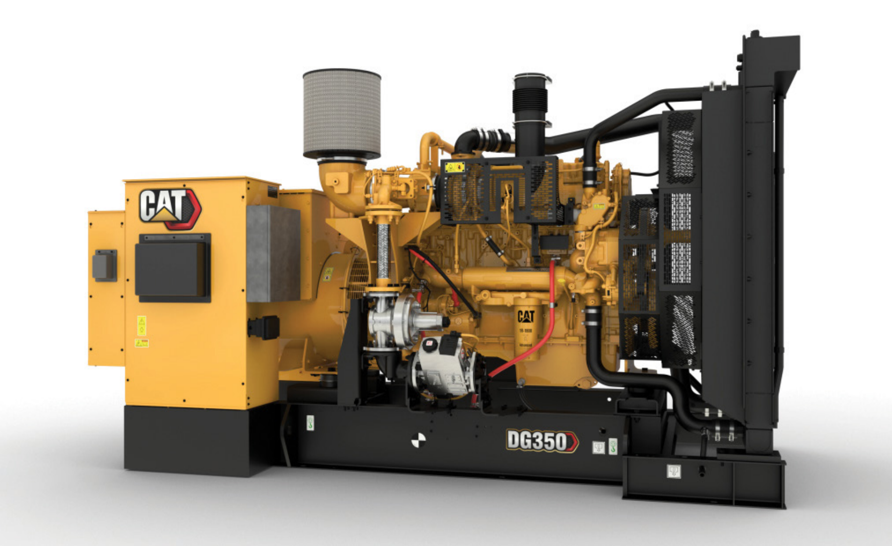
The power choice is the part to notice. The facility's designers decided to go with six Cat CG18 gas generator sets supplying 3 MW of backup power and rated for demand response, enabling the nonprofit to monetize these assets by taking advantage of utility incentives for reducing energy usage during peak demand. The 3 MW of nameplate capacity will be earning the foodbank money. The mission funded the microgrid; the microgrid, increasingly, helps fund the mission.

VPPs, ADER, and the Next Decade of Backup Power

Push Gregory out a decade and she describes a grid that already looks different. "As we consider what the global energy landscape will look like in the future, utility grids are facing significant constraints and stress from rising peak demands, weather volatility, and the increased penetration of renewables. We're also seeing power generation becoming more dispersed and less centralized," she said. Her framing of why dispersion matters is worth holding onto: "When centralized systems fail, they fail on a large scale, while dispersed power can keep critical loads alive when transmission is lost," Gregory noted.

Demand growth is outrunning supply

3. *A Cat D100 GC diesel generator set provides backup power for a wildlife ranch. Courtesy: Cat Electric Power*



4. The Cat DG350 gas generator for stationary standby and demand response applications. Courtesy: Cat Electric Power

expansion, according to Gregory. "Load growth from data centers, EVs [electric vehicles], and the overall movement toward electrification is faster than the ability to build centralized infrastructure. While backup power generation will always be a necessity [Figure 3], customers now understand the value in making traditionally idle backup assets visible and dispatchable to provide capacity and demand response."

Virtual power plants (VPPs) are how that visibility becomes revenue. "VPPs, which aggregate customer-sited resources such as backup generation and other DERs, are becoming a more practical way to support grid reliability as a single dispatchable resource that can provide energy and reserve-type services when called upon," Gregory said. She cited the Electric Reliability Council of Texas's (ERCOT's) Aggregated Distributed Energy Resource (ADER) pilot—explicitly designed to evaluate aggregated distributed resources participating in the wholesale sector and responding to ERCOT dispatch instructions—as evidence that the formal industry pathways are starting to open.

Her advice to anyone specifying a system today is procurement-flavored, not technology-flavored: "To avoid getting stranded, buyers should evaluate systems that can start as standby but are easy to turn on for participation later. These systems can include site controls for multi-asset coordination as well as utility protection and power metering. They can also provide a clear path to connect to an aggregation/DERMS layer when programs mature."

Translation: the equipment you bolt down in 2026 should be ready for an energy landscape that does not exist yet—because at the rate it is being built, it will exist before the warranty runs out.

Interconnection Rules and Tariffs Still Block Microgrid Deployment

There is a sober counterweight to all this momentum, and it shows up most clearly in a March 2026 Lawrence Berkeley National Laboratory report on the regulatory barriers facing microgrids. The technology, the authors note, exists today. The blocker is the rule book. "Most existing legal and regulatory frameworks were designed for a centralized, one-way power system, and are often poorly suited to handle systems that independently balance distributed energy resources with local load, like microgrids," the report says.

Three Berkeley Lab findings deserve special attention from anyone contemplating a microgrid.

The first is the "anti-islanding" paradox. Interconnection rules were written, historically, to ensure DERs disconnect from the grid during an outage so utility line workers could safely repair the system. A microgrid's whole value proposition is the opposite: keep running when the grid goes down. The Institute of Electrical and Electronics Engineers (IEEE) 1547-2018 standard provides a sophisticated framework for safe intentional islanding, but the Berkeley authors flag a "regulatory adoption gap"—many jurisdictions still operate under interconnection rules grounded in the older 2003 version, which "effectively prohibits intentional islanding." A facility can buy state-of-the-art equipment and still be told to obey 2003 rules.

The second is the "blue-sky" conundrum. Caterpillar's experts describe gas gensets rated for demand response and DERMS-ready batteries earning income on ordinary days. But the Berkeley report observes that "the industry for earning revenue by providing energy and distribution level grid services back to the utility is underdeveloped or non-existent in most states." Even Federal Energy Regulatory Commission (FERC) Order 2222, designed to open wholesale sectors to aggregated DERs, is being implemented unevenly state by state. The hardware is ready. The industry for what the hardware can do is, in a lot of jurisdictions, still under construction.

The third is rate design. Standby charges, exit fees, and non-bypassable transmission charges all exist for defensible cost-recovery reasons, but they can also, in the Berkeley authors' words, "make an otherwise financially viable local project uneconomical." The economics of monetizing a backup asset depend not just on what the asset can do but on what tariff it lives under.

A Pivot, not a Revolution

The Wright letter, the Cat foodbank customer, the Berkeley Lab report, and the ERCOT ADER pilot are all the same story told from four different chairs. Backup power is no longer a sealed-off insurance policy that earns its keep over a few hours a year while doing nothing the majority of the time. Rather, it is becoming a portfolio of assets—engines (Figure 4), batteries, controllers, fuels—that look like backup when they need to and look like grid resources the rest of the time.

The technology to do this is, by Gregory's and Stutzman's account, mature. The industry designs to pay for it are arriving. The regulatory frameworks to permit it are, in many jurisdictions, 20 years behind. Buyers specifying systems in 2026 will be the ones who decide, with their procurement specifications, whether the 35 GW Wright is hunting for becomes routine grid capacity or stays trapped behind a meter and a 2003-vintage interconnection rule.

The lights, in either case, will stay on. The question is who gets paid for keeping them on—and whether the asset that does it is allowed to do anything else. ■

*—**Aaron Larson** is POWER's executive editor.*

Advanced Technologies Tackling Task of Grid Hardening

Companies are deploying a variety of strategies in efforts to strengthen the power grid against severe weather and other issues.

Darrell Proctor

Natural disasters are occurring more frequently, and the severity of these events is growing as well, with more people and property in their path. Electric utilities know this all too well. Winter storms (notably ice storms), tornadoes, tropical storms, hurricanes, and wildfires increasingly threaten the reliability of the power grid. Keeping the lights on, and restoring power in the wake of extreme weather, continues to be a challenge for power providers and grid operators. The U.S. Department of Energy has said the average number of weather-related power outages has increased by nearly 80% over the past 15 years.

Hardening the grid against natural disasters (Figure 1) is a growing industry, as groups work to develop technologies to reduce the risk of damage from weather to power generation and power transmission equipment. Weatherization techniques, smart meters, monitoring systems, predictive analytics, better forecasting tools, and more are helping the electricity sector recognize problems more quickly. It's part of a widespread strategy to be proactive against threats to the grid, rather than simply reactive. New technologies are supporting power reliability and resilience.

1. Severe weather, including lightning, is a major cause of power outages. Electric utilities and grid operators are using a variety of technologies to harden the power delivery system against extreme weather events. Courtesy: kijevskymarek / Envato Elements

Jeremy Ellis, director of Power Strategies at OBM, an energy management group, said, "Hardening starts with a mix of physical upgrades and better operational visibility, including more durable materials, undergrounding where feasible, and smarter siting of critical assets. But physical reinforcement is only part of the equation. Grid operators also need better real-time visibility into what is happening across the system. Smart grid technologies, sensors, and more distributed architectures such as microgrids can help utilities break a large, complex system into smaller, more manageable sections, making it easier to identify issues quickly and respond before they escalate. The more proactive a utility can be with monitoring, planning, and load control, the more resilient the system becomes."

Richard Gray, innovation director at S&C Electric Co., told *POWER*, "Hardening generation and transmission is part of the equation, but it breaks down if the distribution system isn't built to carry that same level of resilience. At the medium-voltage level, it's less about building everything bigger and more about making the system behave better under stress, using automation and protection to isolate faults quickly and restore service in smaller sections." Gray added, "Job one is improving how the system behaves when something goes wrong … that means examining how you can segment feeders and deploy protection that can isolate and restore automatically. Once you've done that, you can integrate new demand without taking on the same level of outage risk.

"That approach improves both resilience and overall grid utilization, turning a passive network into something more adaptive so failures are contained instead of widespread," said Gray.

Searching for Strategies

Fortifying electrical infrastructure against extreme weather and other disasters has fostered a variety of programs and strategies, including many that include smart technologies such as artificial intelligence (AI), automated switches, advanced sensors, and real-time monitoring to improve resilience.

Troy Marshall, vice president of Fire Proofing at NanoTech Materials, an advanced materials company, told *POWER*: "Utilities and grid operators are increasingly under pressure to adopt hardening strategies for their power generation and transmission equipment, especially since the electrical grid both contributes to wildfire risk and is itself at risk from wildfires. Equipment from the electrical grid accounts for roughly 3% of fires burned nationwide. With much of the existing grid not initially designed to withstand today's extreme weather events, a number of strategies are being considered to address these risks and minimize the likelihood of rolling blackouts.

"Common approaches include burying powerlines, replacing aging poles, and managing vegetation. While effective, these methods can be costly, require significant downtime, and are often difficult to scale across large service areas. To complement these strategies, utilities can focus on strengthening the actual infrastructure materials," said Marshall. "Wood and timber assets, such as distribution poles and wooden barrier structures along corridors, are particularly vulnerable to wildfire conditions and already require ongoing maintenance. Protective coatings engineered with high reflectance, high emissivity, and low thermal conductivity can reduce heat absorption, reflect radiant energy, and act as a thermal barrier against temperatures well above the 1,800F to 2,200F range typical of wildfires. These materials offer a cost-effective way to

2. Crews install underground conduit for medium-voltage distribution cable—a weather-hardening approach increasingly favored over overhead lines in storm-prone regions. Courtesy: wirestock / Envato Elements

reinforce existing assets and improve protection without requiring full infrastructure replacement."

Said OBM's Ellis: "Efforts to harden systems have taken on more urgency in recent years as extreme weather events become more frequent and damaging. From a structural standpoint, utilities should always be thinking about how transmission infrastructure performs under extreme weather stress, whether that means high winds, ice, snow, flooding, or prolonged heat. At the same time, hardening is not just about building stronger assets, but about using data to better forecast risk and inform planning decisions. Planning should be informed by historical operating patterns such as weather-related grid stress. When operators can analyze when and where the grid has experienced strain in the past, and compare that against predicted weather conditions, time of day, and load behavior, they can better anticipate where stronger structural protections may be needed most, before damage is inflicted. In that sense, hardening is not just about building stronger assets. It is also about using data to forecast risk more effectively and plan around both grid operations and infrastructure investment with greater precision."

Saurabh Chatterjee, senior vice president and onshore renewables business line leader for WSP in the U.S., said, "Transmission lines and towers can be structurally hardened using proven engineering designs that increase their ability to withstand extreme wind, ice, and snow by strengthening the entire system, from foundations to conductors. This typically includes designing structures to higher wind and ice load criteria, using more robust tower geometries such as steel or concrete monopoles instead of aging lattice structures, deepening and reinforcing foundations to prevent overturning or scour, and upgrading conductors to stronger, low-sag types with anti-galloping and vibration control hardware. Additional resilience is achieved by shortening spans, reinforcing cross arms and connections, designing key structures to prevent cascading failures, and integrating real-time monitoring [such as weather, strain, and ice sensors] so operators can derate lines before damage occurs. Together, these measures shift transmission design from minimum code compliance toward resilience-oriented engineering that significantly reduces storm-related outages and speeds recovery."

Robert Wall, associate principal at Perkins&Will, an architecture and design group, noted specific measures electric utilities should take to harden equipment. "One of the most impactful first steps for any utility—or any type of physical asset for that matter—is developing a digital twin of its system," said Wall. "Digitization gives operators a much clearer picture of how assets perform and how best to plan for hardening, expansion, and future demand.

"From there, prioritizing underground transmission and distribution where possible makes a big difference in reducing weather exposure [Figure 2]. Just as important is ongoing monitoring of both assets and environmental conditions so decisions can be proactive rather than reactive," he said.

AI Plays a Role

The power industry experts who spoke with *POWER* acknowledged that AI plays a role in grid hardening, just as it does in other aspects of power generation and transmission.

"If you're trying to run a more utilized, more dynamic grid, visibility is non-negotiable," said Gray. "Remote monitoring at the distribution level gives operators a real-time view of what's happening, which is critical as loads grow and become less predictable. AI can help make sense of that data, flagging abnormal conditions or emerging risks, but it's really an assistive tool, not a replacement for engineering judgment."

"Yes, hardening today's power plants and transmission systems really should include remote monitoring, and this is where AI could make a big difference," said Chatterjee. "On the transmission side, utilities can't realistically have people everywhere all the time, so they use sensors, cameras, drones, and weather stations to keep a constant eye on power lines. AI helps make sense of all that information by spotting early warning signs like lines starting to sag too much, ice building up [Figure 3], vegetation getting too close, or equipment behaving differently than normal, so operators can step in before something breaks.

3. Winter storms can cause major damage to power lines and other electricity delivery infrastructure. Ice can form on power lines, causing them to sag or even break. Such events have caused major power outages in recent years. Courtesy: koldunova / Envato Elements

"Inside power plants, AI plays a similar role but focuses on the machinery itself. Thousands of sensors track things like temperature, vibration, pressure, and electrical performance, and AI looks for subtle changes that humans would never notice in real time," said Chatterjee. "That allows operators to fix or adjust equipment before it fails, instead of reacting after a forced outage.

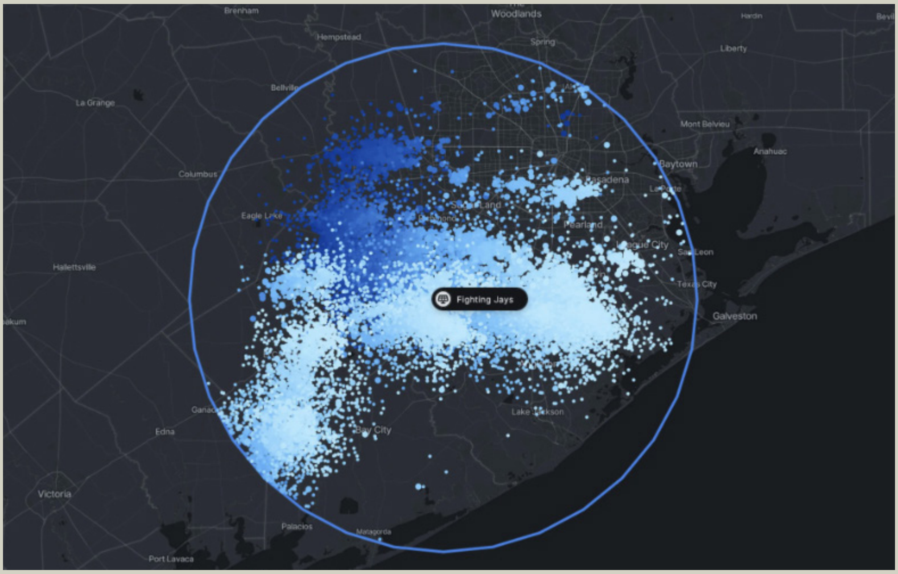
"Taken together, AI turns hardening from a one-time construction effort into something ongoing and proactive," said Chatterjee. "Stronger poles, towers, and equipment reduce the chance of failure, while remote monitoring and AI help utilities see problems coming, respond faster during extreme weather, and keep the system running more reliably day to day."

Ellis told *POWER*: "Remote monitoring is the difference between reacting to outages and preventing them. Many power lines and grid assets are located in isolated or hard-to-access areas, which makes constant in-person inspection impractical. Remote monitoring creates a line of sight into conditions as they develop, helping operators detect early warning signs such as overheating, equipment degradation, or wiring failures before they turn into outages or safety events.

"While technologies like drones may play a larger role over time as a supplemental visibility tool, the priority today is integrating continuous monitoring into core operations," said Ellis. "That visibil-

Managing Weather Risks Through Modeling and Monitoring

One of the companies involved with modeling and monitoring grid infrastructure, and protecting power generation and transmission assets, is Vaisala Xweather, a weather intelligence group that works with various sectors, including energy. Hans Loewenheath, lead product manager at Vaisala Xweather, said, "Weather-related threats, including lightning, hail, and high winds, are among the most destructive and costly forces acting on power infrastructure. Hardening against these threats starts with knowing exactly where and how hard your infrastructure has been hit or could be hit." Loewenheath told *POWER*, "At Vaisala Xweather, we work with utilities to harden their systems by turning real-time and historical weather intelligence into proactive operational and engineering decisions. In fact, 12 of the top 15 revenue-generating U.S.-based investor-owned utilities (IOUs) incorporate Vaisala Xweather lightning data into their engineering analysis procedures."



4. The computer image at left shows an approaching hailstorm that threatens the Levelland solar farm in Texas. Vaisala Xweather will issue alerts, enabling the farm's operator to stow the solar panels in the correct direction to reduce the threat of damage to equipment, as shown at right. Courtesy: Vaisala Xweather

Loewenheath continued, "When it comes to hardening against lightning, using historical lightning exposure data helps guide where to invest in protective equipment such as surge arrestors, improved shielding, and additional insulation." Loewenheath said the group's "Exposure Analysis capability lets utilities query every lightning strike within a defined buffer of a specific transmission line corridor. For example, 0.5 miles of a specific transmission line over any window of time from one to 60 months. This tells operators precisely which segments have accumulated the most strikes since their last equipment upgrade and informing targeted reinforcement so that surge arrestor replacement and insulation investment goes where it's actually needed versus blanket spending across hundreds of miles of line."

Robinson Wallace, research scientist at Vaisala Xweather, noted that hail "is an increasingly serious hazard, particularly for solar assets. Hail damage now accounts for more than 50% of solar industry losses, with the average claim running $58 million." Wallace said his company has developed an internal advanced hail forecasting model that integrates lightning detection with radar, satellite imagery, and numerical weather prediction (Figure 4).

"When a hail forecast intersects a set buffer zone around a solar farm, the system triggers an alert to stow panels," said Wallace. "The same convective processes that form hailstones generate the charge separation behind lightning strikes, which means our lightning network detects the preconditions for severe hail before stones are large enough to fall. In a recent validation study of 170 confirmed severe hail events, our forecast model achieved zero misses and delivered an average warning lead time of 37 minutes, with at least 20 minutes of advance notice in 95% of cases and at least a 10-minute lead time for 100% of cases. This dependability in forecast allows solar operators to shift from manual weather monitoring to automated stow protocols and protect their assets from costly repairs or replacements."

Loewenheath said that most transmission lines "face similar structural problems: they were spec'd to weather conditions that existed when they were built and have degraded due to extended exposure to severe weather. For example, if equipment has been repeatedly used after withstanding lightning, the original equipment ratings, number of surge arrestors, shielding wire geometry, ground resistance, etc., may now be insufficient. This is when utility companies need location-specific, multi-year weather records to size infrastructure for the actual threat environment and not just historical averages that may no longer reflect current storm patterns and damage impact." Loewenheath told *POWER* that his group's exposure analysis "provides a direct comparison between observed lightning strike density along a transmission corridor and the design specification the line was originally built to meet. If actual lightning exposure has begun to exceed a line's typical design specification of a 20-kA threshold, or has simply taken a toll on the equipment over time, that's a direct signal to upgrade."

Loewenheath said Vaisala Xweather has worked with the Tennessee Valley Authority (TVA) to analyze the TVA's transmission network using Vaisala lightning data. Loewenheath said the group "found that average strike magnitude across [TVA's] service territory is approximately 20 kA. This number now anchors their equipment specification standards." Loewenheath added that data "also revealed that western portions of their territory see materially higher flash density than the east, where terrain provides natural shielding. That insight shaped exactly where hardening capital went and led to mitigation techniques like increasing insulation through additional insulator bells and fiberglass cross-arms, installing or improving shield wire geometry, upgrading ground resistance, and installing surge arrestors on the highest-exposure segments."

Wallace said remote monitoring is no longer optional for a modern, resilient grid; it is foundational. Wallace said the value of that monitoring "multiplies significantly when it is paired with AI-driven analytics. Vaisala Xweather's hail forecasting model, for example, uses data fusion to combine real-time lightning detections from the

Vaisala Xweather Lightning Network with radar returns, satellite imagery, and numerical weather model output so that our forecast system identifies severe hail conditions before the stones are large enough to fall. The system synthesizes these inputs to generate hail threat forecasts up to 60 minutes ahead. For solar operators, that lead time is the difference between a stowed, protected panel farm and a catastrophic, costly loss."

"For transmission infrastructure, AI-assisted lightning exposure analysis enables utilities to move from reactive maintenance to predictive asset management," said Loewenheath. "Duke Energy uses Vaisala's National Lightning Detection Network data to run an automated alert system from their Charlotte [N.C.] weather office in protection of their employees. An outer detection ring around each generation and transmission site automatically alerts staff to prepare for work suspension while an inner ring triggers an immediate cease work and seek shelter alert. Work can resume after a 30-minute [pause] since [the] last lightning strike alert, protecting employees across Duke's service territory comprised of transmission sites, conventional power plants, solar facilities, and wind farms.

"Job one is knowing your actual exposure. You can't prioritize hardening investment without asset-level data on where your infrastructure has been hit, how often, and how hard," said Loewenheath. "Regional averages won't tell you which line segment needs new surge arrestors, but a corridor-level exposure analysis will. From there, the sequence is straightforward: establish a multi-year lightning baseline for your service territory, run corridor-level exposure analyses to rank your highest and lowest risk transmission segments, then apply targeted hardening procedures like surge arrestors, grounding upgrades, shielding improvements to the worst performers first. Track outage rates afterward and ongoing to measure the return. For generation assets, like solar panels susceptible to hail damage, add automated severe weather alerting to initiate advanced warning and automated panel stow protocols for an extra layer of protection. Finally, revisit your design assumptions regularly. Hardening your infrastructure is an ongoing data-driven discipline as weather patterns and land changes, not a one-time infrastructure project."

ity becomes significantly more valuable when paired with real-time load control, which allows operators to dynamically adjust power consumption and distribution in response to current grid conditions. This can help relieve stress during peak demand, prevent equipment overload, and contain issues before they cascade into larger disruptions."

Ellis added, "Artificial intelligence strengthens this by helping operators make sense of large volumes of real-time and historical data. By identifying patterns between weather conditions, load behavior, and past grid events, AI can flag risks earlier and support more proactive decision-making. Inside a power plant, that might mean detecting anomalies in transformers or turbines before failure occurs. Across the grid, it can help anticipate where strain is building and guide timely operational adjustments. When combined with real-time monitoring and load control, AI supports a more coordinated, predictive approach to maintaining grid stability and resilience."

Wall agreed that AI can provide plenty of value when it comes to grid hardening. "Yes, absolutely. Remote monitoring really is a key part of modern grid hardening. When you combine that with AI, it becomes much easier to move toward predictive maintenance—preempting problems and fixing them before extreme weather exposes weaknesses," said Wall. "These tools can also support smarter power routing, allowing operators to reroute electricity quickly when sections of the grid go offline. On top of that, AI can help identify external risks, like vegetation or other environmental factors and inform management strategies that prevent problems down the line."

Modeling and Monitoring Infrastructure

The experts who spoke with *POWER* agreed on the importance of modeling and monitoring infrastructure to ensure a reliable flow of electricity (see sidebar), from generation to delivery. They said hardening the grid is also optimizing the grid.

"Properly modeling existing infrastructure is the first step to hardening the system against reliability, [and] reducing impacts and events. From a physical perspective, using trustworthy and proven engineering calculations to determine that the design and condition of a structure is still fit for purpose is key," said Brad Johnson, director of Electric Utilities at Bentley Systems, an infrastructure engineering software group. "Because these calculations are complex, and there is such a backlog of work to be done, technology plays a key role in completing this step. Once those assessments begin to be completed, sub-optimal poles, lines, and equipment will need to be refurbished, upgraded, or retired from service as soon as practicable."

Said Johnson, "Continuous monitoring in many forms is important to relate the theoretical and the actual condition of the grid. Where time-series data can improve or enable grid performance, AI will play a role in assessing and framing data and insights for human intervention. A mix of automated [sensor] and manual [human inspection] is key to achieving a holistic assessment. Technology plays a critical role in relating these different data sets."

Ellis told *POWER*: "Job One is installing the equipment and systems that provide real-time visibility into operations. Without that line of sight, it is much harder to make informed decisions, respond quickly, or automate protective actions. Once monitoring hardware is installed, software can deliver granular, timely data on usage, system conditions, and potential faults. From there, the next step is making sure that data connects to control capabilities, so operators can act remotely and quickly when needed. That includes load control, curtailment, and other automated responses that can reduce stress on the grid, lower costs, and in some cases prevent a more serious incident from unfolding.

"Site operators and plant managers are especially important in this process because they understand the operational details of a facility better than anyone else. They know the equipment, the risks, and the realities on the ground," said Ellis. "Hardening works best when utilities combine durable infrastructure with better monitoring, faster, more automated control, and close collaboration with the people responsible for daily site operations."

Marshall said using AI and other advancements can help with the design of new electrical transmission infrastructure. "Utilities and engineers can incorporate targeted structural design improvements to harden transmission lines, including reinforcing tower foundations to withstand thermal stress, increasing conductor spacing to reduce overheating, and minimizing combustible components," said Marshall. "At the same time, extreme heat and wildfires are creating a need to think beyond traditional design standards to extend equipment lifespans. This is why material selection and protection are becoming increasingly important in mitigation efforts. With this approach, utilities can implement structural improvements while simultaneously improving performance. This points to a broader industry shift toward a more comprehensive view of resilience, in which structural strength and material performance are incorporated into the design process from the start."

Deploying Distributed Generation

Moving power generation closer to load also supports grid reliability and resilience, and can be part of a grid-hardening strategy. Distributed energy, with smaller generation assets supporting larger, decentralized output from power plants, can reduce the risk of outages.

Wall, who is co-author of a forthcoming report on the potential of energy storage in commercial buildings from Sidara—a privately owned global collaborative of engineering, design, and professional services firms including Perkins&Will—told *POWER*: "One of the biggest opportunities [for grid hardening] is simply reducing the distance between where power is generated and where it's used, which limits exposure across long transmission lines. Sidara firms work in markets all over the world and design assets and systems in all types of climates. However, from a physical standpoint the mantra is always the same—equipment needs to be designed with flexibility in mind so it can withstand extreme temperatures, vibration, high winds, and other lateral forces during extreme weather."

Wall said, "Adding instrumentation at key connection points—like transformers and substations—makes it much easier to spot issues quickly and get crews to the right place faster. More broadly, if you start to redesign grids around distributed generation, the whole approach to resilience changes quite significantly."

The growth of energy storage systems is directly tied to the use of more distributed energy resources, which includes renewable energy such as solar and wind power. Andrew Hoesly, general manager of SolarTech, a solar power group, told *POWER*: "From our side, resilience is becoming just as important as cost. As extreme weather events become more frequent, more homeowners and businesses are looking at solar and storage not just for savings, but as a way to maintain power during outages."

Hoesly continued, "Distributed energy plays a different role than traditional grid hardening. Instead of only strengthening centralized infrastructure, it allows power to be generated closer to where it's used. That reduces dependence on long transmission lines that are often most vulnerable during storms." Hoesly added, "On the hardware side, solar systems themselves have become more durable. Modern panels are tested for hail, wind, and extreme conditions, and installation standards have improved significantly. The bigger shift, though, is combining solar with storage, which gives customers a level of resilience that didn't really exist at scale a decade ago."

Wall added, "Energy storage is one of the most effective tools municipalities and asset owners have to improve both resilience and energy security. We will soon be publishing a paper on exactly this issue, demonstrating the benefits and practicalities of implementing this technology in existing buildings. Quite simply, having storage in place allows critical services to keep running during outages and makes recovery much faster when disruptions do occur. It also reduces reliance on a single supply source, which has become increasingly important given recent geopolitical and market volatility. When paired with distributed generation, storage can also help ease peak demand and add another layer of flexibility to the system."

Step-By-Step

Chatterjee offered five suggestions for grid-hardening initiatives, in what he called "a simple, common-sense order. First, figure out where you're most likely to fail, which lines, substations, or plants are most exposed to storms, heat, flooding, or wildfires, and what happens if they go down. Second, fix the things that break most often, especially aging poles, towers, conductors, and flood prone substations [Figure 5], these upgrades prevent outages before they start.

"Third, give the system better visibility, using sensors, automation, and remote monitoring, so operators can see problems developing and act early. Fourth, plan for fast recovery, because no grid is unbreakable, sectionalizing, redundancy, and operational playbooks matter, as much as steel and concrete." Finally, Chatterjee said, "Design for what's coming, not what already exists, by accounting for load growth, climate change, and new customers like data centers. In simple terms: know your risks, strengthen the weak spots, add eyes and controls, recover quickly when things fail, and keep future conditions front and center."

5. Flooding is one of the biggest threats to substation equipment. In Lockport, Louisiana, Entergy crews are building a reinforced flood wall around the Valentine substation, the first of five projects like it planned across the state. Courtesy: Entergy

Johnson told *POWER* there are at least three steps that any electric utility should take as part of a grid-hardening strategy. "Step one, assure that the existing grid is fit for purpose," said Johnson. "Step two, extend and modify the grid to fit what is most likely to come next. Step three, build flexibility and resilience to demand, policy, and engineering change into current and future investments."

Marshall also offered advice for utilities and power grid managers, echoing Chatterjee and Johnson. Said Marshall, "The first step is identifying the infrastructure that is most exposed, particularly in regions with elevated wildfire risk. In those areas, wood and timber assets are often among the most vulnerable and should be prioritized. From there, utilities should evaluate how to protect high-risk assets in a practical and scalable way. Full system replacement is rarely feasible in the near term, so many utilities are turning to solutions that can support existing infrastructure. Material-based approaches, including fire-resistant coatings rated to withstand temperatures up to 3,272F, offer a way to add protection to vulnerable wood and timber assets without major disruption.

"That said, no single solution addresses every risk," said Marshall. "Utilities that take a layered approach, starting with their most exposed assets and combining targeted structural upgrades, material protection, and better visibility into how energy moves across the system, will be better positioned to strengthen resilience and manage the conditions they are facing today." ■

*–**Darrell Proctor** is a senior editor for POWER.*

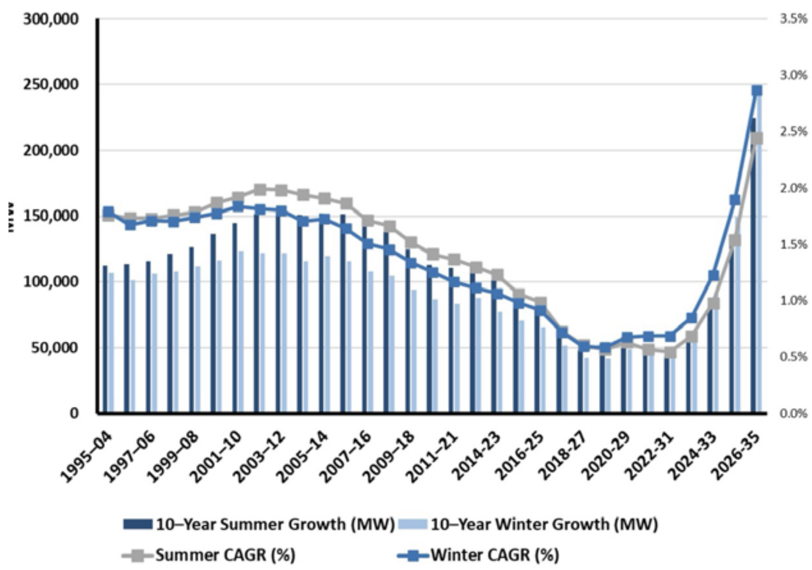
Five Winters After Uri: Why Winter Readiness Must Go Beyond Weatherization

From EOP-012-3 to Order 587-AB, from Cold Weather Critical Component inventories to dual-fuel conversions, the bulk power system has spent five years rewiring how it prepares for extreme cold. Winter Storm Fern, the latest test, showed the system ran "very close to the edge."

Sonal C. Patel

The last five winters have given the North American power sector a harried sequence of tests. After the calm in the years following the polar vortex of 2014, Winter Storm Uri delivered a catastrophic rupture in a 13-day event in February 2021, precipitating 61,305 MW of unavailable generation and 23,418 MW of firm load shed in the largest controlled firm load shed event in U.S. history. Elliott followed in December 2022 and drove 90,500 MW of coincident unplanned generation outages across the Eastern Interconnection and 5,400 MW of firm load shed in the Southeast. By the January 2025 arctic events—22 days across Winter Storms Blair, Cora, Demi, and Enzo—unplanned generator outages still peaked at 71,022 MW across the Eastern and Texas Interconnections, though operators avoided firm load shed. And despite lessons urgently learned and implemented in the aftermath of those storms, Winter Storm Fern, which spanned 19 days from Jan. 23 to Feb. 10, 2026, and stressed the bulk electric grid across the Midwest, Northeast, and South, proved "a near-miss event," as Jim Robb, president and CEO of the North American Electric Reliability Corporation (NERC), testified before the House Energy Subcommittee in March.

During Fern, grid operators declared 26 Energy Emergency Alerts (EEAs), including two EEA3s, the highest alert level, one step from firm load shed, Robb testified. In tandem, the Department of Energy issued 20 emergency orders under Section 202(c) of the Federal Power Act: seven in Florida, four in the Southeast, four in the Mid-Atlantic, two in New England, two in Texas, and one in New York. "These outcomes should be no cause for complacency," Robb warned.



1. The North American Electric Reliability Corporation (NERC) projects 10-year aggregated summer peak demand growth of 224 GW and winter peak demand growth of 245 GW across the North American bulk power system—the highest compound annual growth rates since NERC's tracking began in 1995. Courtesy: NERC January 2026 Long-Term Reliability Assessment

"The wide array of actions to manage Fern may have had far different results with a larger, longer, colder storm." He also noted, candidly, that the storm was not as cold as initially forecast and that widespread school and business closures reduced demand, which potentially eased pressure on the system.

But the ultimate test Fern administered, as other recent winter storms have done, was of capacity adequacy—whether enough generation is available at peak—and of energy adequacy—whether the fuel and stored energy behind that generation can sustain output across a multi-day event. Capacity adequacy during Fern seemed to meet its mark. PJM met its peak of 140,049 MW on Jan. 29 against outages, which averaged 18 GW to 19 GW, according to a February 2026 PJM Operating Committee cold weather update. Energy adequacy, however, showed strain. For several days in late January, all gas-fired generation in New England relied on scheduled liquefied natural gas (LNG) injections, according to ISO-NE data cited by José Costa, president and CEO of the Northeast Gas Association, at the hearing.

A New Winter Load Profile

The bigger reason for the "near miss" assessment, Robb said, was that Fern "closely tracked many risks" NERC identified in its *2025 Long-Term Reliability Assessment* (LTRA), released that January. The annual 10-year-forward outlook projected that 13 of 23 North American assessment areas face resource adequacy challenges over the next five years. It also projected that summer peak demand could surge 224 GW through 2035, that winter peak demand could surge even more—245 GW over the same period—and that winter capability from solar and battery resources will lag the additions needed to offset retiring fossil capacity (Figure 1).

NERC's *2025–2026 Winter Reliability Assessment* (WRA), released in November 2025, meanwhile, says that aggregate peak demand across the NERC footprint rose 20.2 GW (2.5%) winter-over-winter, while net resources increased only 9.4 GW—and of that resource increase, generation accounted for just 1,335 MW. The larger share came from demand response and battery additions whose output can diminish in sustained extreme cold. Seven assessment areas entered the season carrying elevated reliability risk: NPCC-Maritimes, NPCC-New England, SERC-East, SERC-Central, Electric Reliability Council of Texas (ERCOT), WECC-Basin, and WECC-Northwest, per the WRA. NERC also warned that risks are tied less to normal peak conditions than to the combination of extreme cold, above-normal load, generator outages, reduced output from intermittent resources, and fuel constraints. The WRA also underscores that natural gas production and delivery can be disrupted by freezing conditions, that freeze protection for gas infrastructure remains voluntary in most of North America, and that gas-electric market timing misalignments continue to complicate generator fuel procurement ahead of severe winter conditions, especially over holiday weekends.

For now, the winter load profile shift is most pronounced in the Northeast. ISO-NE's *Final 2025 Heating Electrification Forecast* projected that the regional summer peak would rise from 24,803 MW in 2025 to 32,021 MW in 2045, an increase of about 30%. Winter peak demand, by contrast, is set to essentially double over the same period, reaching 40,278 MW by 2045, driven primarily by the electrification of space heating and transportation. More significantly, ISO-NE expects to cross over to a winter-peaking system by the mid-2030s, owing to heating electrification, which alone is forecast to contribute 5,533 MW to the 50/50 winter peak in 2035–2036. However, other regions may be following that trend. WECC-Northwest's winter peak for the 2025–2026 season is projected to be 9.3% above the prior year, driven by data center load, building electrification, and semiconductor manufacturing, according to NERC's WRA.

A Growing Body of Cold Weather Mandates

Given that complex risk profile, since Uri, the Federal Energy Regulatory Commission (FERC), NERC, regional entities, and state regulators have layered new winter-readiness requirements and operating expectations onto the bulk power system. The most direct mandatory standards govern generator cold-weather preparedness, but the broader response also affects grid operations, load-shed coordination, seasonal transfer studies, load forecasting, critical natural gas infrastructure identification, and gas-electric coordination. The mandates now in force include the following.

EOP-012-3—Extreme Cold Weather Preparedness and Operations. Effective Oct. 1, 2025, the standard became the third iteration of the post-Uri generator standard in two and a half years and the most consequential. While FERC approved the first version in February 2023, it found it had ambiguous applicability and open-ended compliance windows. EOP-012-2, which followed in October 2024, included a corrective action regime that FERC again ordered tightened. EOP-012-3, approved Sept. 18, 2025 (Docket RD25-7-000), gives the 1,314 U.S. generator owners on NERC's compliance registry 48 months to install new freeze protection and 24 months to fix existing measures. It requires any unit entering commercial operation on or after Oct. 1, 2027, to operate at its Extreme Cold Weather Temperature on day one. It also strips ambiguous "cost" language from the Generator Cold Weather Constraint definition and requires compliance enforcement authority validation, reviewed every 36 months. And it directs NERC to file biennial reports to FERC from October 2026 through October 2034.

EOP-011-4—Emergency Operations. FERC in February 2024 approved EOP-011-4, a standard that carries forward the emergency operations framework for reliability coordinators, balancing authorities, and transmission operators. It adds the Uri-driven requirement to prioritize identified critical natural gas infrastructure loads in any manual load shed, given that cutting power to a compressor station in a cold snap can knock out fuel supply downstream.

TOP-002-5—Operations Planning. FERC also approved TOP-002-5 alongside EOP-011-4, which directs transmission operators and balancing authorities to incorporate extreme cold weather into operations planning analyses, including the ability to serve forecast load and maintain reserves under defined cold conditions.

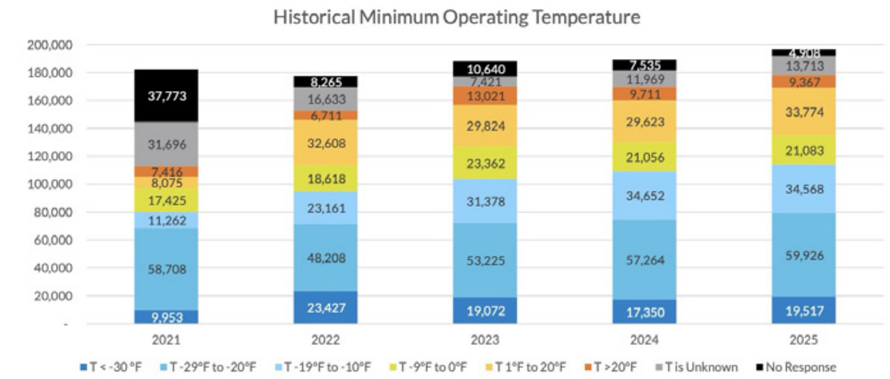
Order No. 896 (June 2023)—Transmission Planning for Extreme Weather. The order directs NERC to develop a reliability standard requiring transmission providers to incorporate extreme heat and cold into their planning studies, including benchmark events, corrective action plans, and wide-area assessments. NERC's Board of Trustees adopted TPL-008-1 on Dec. 10, 2024, and NERC filed the proposed standard with FERC on Dec. 17, 2024 (Docket RD25-4-000). FERC approved TPL-008-1 at its February 2025 commission meeting. The standard applies to transmission planners and planning coordinators, and requires an Extreme Temperature Assessment at least every five years.

Order No. 897 (June 2023)—One-Time Extreme Weather Vulnerability Assessments. The order requires transmission providers to submit one-time reports analyzing their systems' vulnerability to extreme weather. Transmission providers filed reports in October 2023, which inform the ongoing development of the Order 896 standard.

Generator Efforts Coalesce Around a Common Framework

But even as the federal mandates were being forged, industry had begun stepping up to guard against extreme cold temperatures and freezing precipitation from severe winter storms and to curb significant generating unit outages, derates, and failures to start.

Among common causes are "freezing of critical systems such as instrumentation and controls, sensing lines, drains, vents, cooling water intakes, coal feeders, and ash handling," according to a December 2024 EPRI report authored by principal investigator Brad Burns. Burns' general recommendations span the full lifecycle of a unit-specific Cold Weather Preparedness Plan (CWPP). These include determining an Extreme Cold Weather Temperature (ECWT) for each generating unit, identifying Cold Weather Critical Components (CWCCs) whose freezing would likely cause a forced derate exceeding 10% of unit capacity for more than four hours, a startup failure, or a forced outage, documenting freeze protection measures for each CWCC, conducting annual inspection and main-



2. The Midcontinent Independent System Operator's (MISO's) annual winterization survey of generation owners shows steady improvement in cold-weather operating capability since 2021. Courtesy: MISO 2025–2026 Winter Readiness Workshop, Oct. 29, 2025

tenance, and training all personnel responsible for implementing the plan.

The Midcontinent Independent System Operator's (MISO's) winterization survey points to the same trajectory at the fleet level: the share of fleet capacity rated to operate below 0F has grown substantially, while capacity with unknown cold-weather ratings or rated only above 20F has shrunk markedly (Figure 2). The grid operator—whose footprint stretches from Manitoba to the Gulf Coast and which lost roughly 21 GW of incremental generation during both Uri (February 2021) and Elliott (December 2022)—has built a multi-layered cold-weather program. It pairs the annual winterization surveys and cold-weather drills with a multi-day forward reliability assessment and commitment process that issues capacity advisory and conservative operations declarations one to five days ahead. An uncertainty management model sizes short-term reserves to the 99.7th percentile of forecast risk, and new operations uncertainty platform dashboards track generator fail-to-start and gas pipeline risk. The payoff showed during the January 2025 arctic events—Winter Storms Blair, Cora, and Enzo—when incremental outages peaked at roughly 9 GW against a 108-GW systemwide peak, well below Uri- and Elliott-era levels.

Burns treats the ECWT—calculated as the lowest 0.2 percentile of hourly December-January-February temperatures from January 1, 2000, through the date of calculation, recomputed at least once every five calendar years—as a floor rather than a design target. In a recent ERCOT webinar, he noted that "meeting the ECWT is the minimum requirement for compliance but ensuring winter resiliency may require sustained operation at lower ambient temperatures." During Winter Storm Elliott, ambient temperatures in Knoxville fell below the ECWT for roughly five hours, rose slightly, then fell below the ECWT for an additional 20 hours.

Burns also recommended that heat trace and insulation be treated as a single integrated system, with the complete system tested annually in summer to identify failed circuits and schedule repairs before winter. Heat trace panels should be inspected every three hours during cold weather events. He further urged redundant heat-trace circuits sized for wind-chill effects, heated enclosures designed to maintain temperatures above freezing at the ECWT, and continuous monitoring via smart panels, current-draw measurement, or infrared cameras rather than single end-of-circuit LEDs prone to silent failure.

Heat trace failure remains the dominant cause of cold weather plant outages.

Inspections Remain Integral. ERCOT, operating under Texas's 16 TAC §25.55 Weather Emergency Preparedness rule, has run the deepest disclosed inspection program. ERCOT Director of Weatherization and Inspection David Kezell, in an October 2025 workshop presentation, reported 4,079 cumulative weatherization inspections across four winter seasons and three summer seasons since the rule took effect: 2,646 at generation resources and 1,433 at transmission service provider facilities. Kezell reported that outages of non-intermittent renewable resources—the gas, coal, nuclear, hydro, and battery fleet—"stayed at a consistently low level across the 2024 and 2025 winter storms." Compared to Uri outages, which peaked above 30,000 MW, outages during Winter Storms Heather (January 2024), Enzo (January 2025), and Kingston (February 2025) each stayed near 8,000 MW to 10,000 MW, he said.

The CWCC List Has Become the Central Organizing Artifact. Every disclosed ERCOT program also now centers on a CWCC list—a §25.55-defined inventory of components whose failure causes a trip, a derate exceeding 5%, or a failure to start. ERCOT's October 2025 inspection guidance uses two February 2025 transformer trips to illustrate the stakes. A generator step-up (GSU) transformer's load tap changer (LTC, a device that adjusts voltage as load varies) tripped on low oil during Feb. 19–20, 2025. The LTC was not on the facility's CWCC list, ambient was below the LTC design threshold, and the low-oil alarm reached the remote operations center (ROC) on Feb. 19 but was not telemetered for immediate operator response, with the trip following a day later. A second GSU tripped at 8:07 a.m. on Feb. 19 on a false low-oil reading caused by improperly calibrated micro switches on the oil-level gauge. No warning signal was sent to the supervisory control and data acquisition (SCADA) system before the trip. ERCOT now directs operators to add GSUs and LTCs to CWCC lists, telemeter low-oil alarms to the ROC, train ROC staff on alarm response, and validate oil-level sensors at commissioning and after maintenance.

Heat Trace Monitoring Has Emerged as a Standard Fix. Heat trace failure remains the dominant cause of cold weather plant outages, and the general response has been to move away from single-LED status indicators—which can burn out without warning—toward networked monitoring that reports each circuit's condition to the control room. The Tennessee Valley Authority installed smart panels across its fleet alongside new heat trace and insulation, permanent hard-side enclosures, and permanent heater evaluation and replacement. Oglethorpe Power installed a heat trace distributed control system (DCS) interface, integrating heat trace status into the plant's main control system. Wolf Hollow 1 in Texas, operated by EthosEnergy, complements that approach on the manual side, adding monthly amperage readings at heat trace panels and labeling critical breakers inside the panels for faster operator access.

Enclosures and Wind Breaks Are Moving from Improvised to Engineered. Temporary tarps and plastic sheeting were the first line of defense against wind-driven cold in the years after Uri, but they ripped and let cold air through the seams. Power generators have been embracing durable, permanent structures. ERCOT's best-practice guidance calls for heavy-duty tarps, plywood, durable siding, or planking at all elevations—with reinforced plastic permitted only at ground level—alongside weekly inspections through winter. Wolf Hollow 1 adopted heavy-duty shrinkwrap with zipper-access doors to hold heat and resist wind, replacing earlier tarps that ripped in high winds. Calpine has gone even further, adding heated enclosures atop heat recovery steam generators at specific locations to minimize personnel exposure during extreme cold.

Sensing-Line Replacement Targets the Residual Vulnerability. Sensing lines—the small-diameter pipes that carry pressure or level signals from process equipment to transmitters—are among the highest-risk components for cold-weather failures, EPRI's December 2024 report notes. In many plants, they lack insulation, heat trace, and enclosures. They also carry little or no flow most of the time, and they are vulnerable to freezing during cold startup. Some operators are eliminating the most freeze-prone sensing lines entirely. Oglethorpe Power installed guided wave radar drum-level indication on all three of its combined cycle gas turbines, replacing freeze-prone drum-level impulse equipment. The radar is mounted on a chamber and sends a low-energy microwave pulse down a probe and back to the device, so that nothing fluid-bearing is exposed to ambient temperature.

The Framework Has Extended to Renewables and Storage. While cold-weather mandates were originally written with thermal plants in mind, ERCOT's §25.55 framework now applies to renewable and storage operators, who face distinct freeze risks. Enel Green Power, which operates more than 4,500 MW of solar, battery storage, and wind in the ERCOT region, last spring certified

3. Ice accumulation on Tennessee Valley Authority (TVA) transmission line conductors during Winter Storm Fern. TVA transmission lines are designed to withstand 0.25 to 1.6 inches of ice depending on conditions, and design tension is limited to account for extreme cold and ice loading. TVA reported that no structures or conductors failed solely due to ice and wind during the storm. Failures occurred only where falling trees added weight to lines. Source: Tennessee Valley Authority

111 site personnel and technology specialists on an internal training platform, and field inspections now flow through Survey 123 software to dedicated technology specialists for review, while SAP work orders track repairs. Enel's critical failure points for battery storage include conduit and door seals on battery containers, thermostat functionality and glycol levels in the battery temperature control system, inverter heating elements, and fire suppression water that must not freeze. At solar substations, the critical points include heater functionality and insulating gas pressure on outdoor gas-insulated circuit breakers, motor-operated disconnect heaters, main power transformer cabinet heaters, tap changer cabinet heaters, breather desiccant, and Hydran meters that monitor transformer oil for dissolved gases.

A Year-Round Cadence Has Become Standard. Rather than treating winter readiness as a fall sprint, Constellation Energy holds bi-weekly seasonal readiness meetings, conducts pre-season CWCC list reviews in both March and October, holds winter system reviews in September, completes site-specific training and staffing review in November, and operates through the December-to-February winter run. At Calpine, operators conduct a post-winter lessons-learned meeting in March or April, site-specific readiness meetings May through July, a finalized work scope by August or September, a procedure review in October, training and certification of readiness in November, and all winter preparations complete by December 1.

Transmission-Side Winterization Is Its Own Discipline. Because transmission service providers (Figure 3) operate in a different equipment universe than generators, Oncor organizes its program into three operational categories: seasonal preparations, declaration of preparedness, and ERCOT inspections. Texas's §25.55 transmission inspection scope covers SF_6 pressure and heaters in breakers and metering equipment, transformer control cabinet heaters, main tank oil levels checked against actual oil temperature, bushing oil levels, nitrogen pressure, and oil quality for moisture and dissolved gases. Pedernales Electric Cooperative runs year-round substation inspections on a 12-day revolving route, sending two inspectors to three or four substations daily. They log battery bank float voltage, cell specific gravity, ventilation fan operation, transformer load tap changer oil filtration pump hours and pressure, and capacitor bank physical integrity each month. CPS Energy uses a layered compliance structure, tracking work at the component level through its CASCADE maintenance management system and at the rule level through an email reminder system.

Dual-Fuel and On-Site Fuel Storage Are the Response to Gas-Supply Correlation. To counter gas supply curtailments during cold snaps, operators in the Southeast, in particular, are responding by adding on-site firm backup fuel. Oglethorpe Power filed a final environmental assessment with the U.S. Department of Agriculture Rural Utilities Service in February 2024 to convert four of six simple cycle combustion turbines at its Talbot Energy Facility in Box Springs, Georgia, to dual-fuel firing on No. 2 diesel. The project added two 1.6-million-gallon fuel oil storage tanks, two 2-million-gallon demineralized water tanks, liquid fuel atomizing packages, and water injection packages. Each turbine is permitted up to 4,200 hours per year on any fuel and up to 450 hours per year on diesel. The on-site fuel supply supports full-load operation of all turbines for approximately 70 hours without resupply. Oglethorpe noted in the filing that recent cold snaps in the Southeast had limited or cut off natural gas supplies during periods of high demand. Duke Energy's 2025 Carolinas Resource Plan filed Oct. 1, 2025, with the North Carolina Utilities Commission, takes a similar approach. The plan adds enhanced LNG storage to reduce fuel cost volatility and targets potential two- to four-year extensions of the dual-fuel coal units at Belews Creek, Cliffside, and Marshall.

Gas-Electric Coordination Is Catching Up to the Problem

Still, physical fuel insurance—on-site diesel, LNG storage, dual-fuel coal—addresses only half of the gas-electric correlation problem. The other half involves operational visibility between the two systems during the hours when each is under the most stress. As NERC's Robb told lawmakers in March, the natural gas system's performance and supply to power generators remains "perennial issues during extreme winter events." During every major cold-weather event since Uri, pipelines have run at or near maximum hourly takes, while local distribution companies have curtailed nonfirm power plant customers to protect firm heating loads. According to the November 2023 **FERC-NERC Winter Storm Elliott joint inquiry report**, gas pipeline scheduling data for individual power plants, the geographic locations of pipeline emergencies, and fuel availability information were either unavailable or scattered across pipeline informational postings websites in non-standardized formats—impeding grid operator situational awareness when both systems faced coincident peak demand.

Fern signaled that producer-side improvements are real but partial (Figure 4). Storage was the backbone of the supply response, equaling 30% of total U.S. gas demand over the 10-day stretch, and the 360 billion cubic feet (Bcf) draw for the week ending Jan. 30 was the largest single week EIA had ever reported. Lower-48 production dipped about 13% at its low point but recovered quickly—a smaller decline than in Winter Storms Uri (2021) or Elliott (2022)—while Canadian imports reached 11.1 Bcf per day on Jan. 24, the highest since 2008.

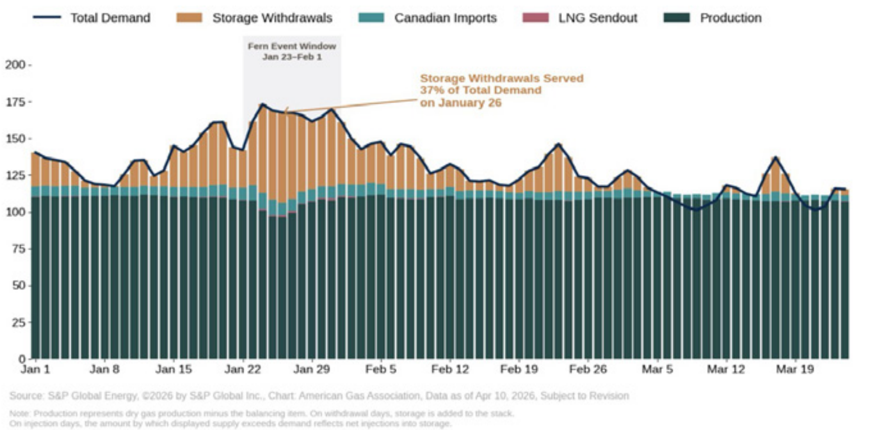
"While production declines were observed and massive storage withdrawals were made, production in the Marcellus and Utica regions remained strong," NERC's Robb told lawmakers in March. "This performance highlights the critical role that natural gas storage plays in supporting electric reliability and demonstrates that many previously observed production challenges can be mitigated by natural gas producers. It also stresses the growing need for assuring sustained winter operations across the natural gas value chain as reliance on natural gas continues to rise." Across the grid, natural gas was the No. 1 electricity source in ERCOT, PJM, NYISO, MISO, the Southeast, and Florida for nine days spanning Jan. 23–31.

That gap has driven a multi-year federal and standards-body effort to formalize gas-electric data sharing. In July 2022, then-FERC Chairman Richard Glick and NERC CEO Jim Robb co-signed a letter directing the North American Energy Standards Board (NAESB) to convene a Gas-Electric Harmonization Forum, citing recommendations in the November 2021 FERC-NERC Uri report. More than 700 individuals from over 370 organizations across the gas and electric sectors participated, and NAESB issued a report in July 2023 with 20 recommendations. The November 2023 FERC-NERC Winter Storm Elliott joint inquiry report then directed NAESB to convene gas infrastructure entities, grid operators, and local distribution companies to improve cold weather communications. NAESB's Wholesale Gas Quadrant (WGQ) Executive Committee approved the resulting new and revised standards on Oct. 24, 2024, and the membership ratified them on Nov. 25, 2024. FERC issued the Notice of Proposed Rulemaking (NOPR) a year later, on Oct. 16, 2025, and the final rule on May 22, 2026—41 months after Elliott.

Notably, the new FERC final rule—Order No. 587-AB (Docket RM96-1-044)—incorporates three revised NAESB WGQ business practice standards, which will require interstate pipelines to publicly post scheduled quantity information for directly connected power plants by cycle, location, RTO/ISO territory, and total scheduled quantity. It also establishes a new "Gas Electric Coordination" posting category on pipeline informational websites to consolidate that data in a single standardized place. Finally, it requires that geographic information about impacted areas, locations, and pipeline facilities accompany every critical notice a pipeline issues during an emergency. Compliance filings are due Sept. 1, 2026, with mandatory implementation by Jan. 1, 2027. Several pipelines, including the Natural Gas Pipeline Company of America, Tennessee Gas Pipeline, and Algonquin Gas Transmission, have already voluntarily implemented the standards. The rule's scope, however, remains narrow. FERC listed the force majeure policy, pipeline reliability metrics, natural gas storage infrastructure, demand response incentives, and weatherization requirements for natural gas infrastructure as outside the scope of the proceeding.

Still, despite the procedural and physical work the power industry has done to improve cold weather performance since Uri, as Fern showed, "the system ran very close to the edge, leaving no room for error," Robb told lawmakers. "A system bordering on the edge during winter extremes should not be normalized." Robb pointed to four areas requiring acceleration. "We just got to get off the dime and effectively address siting and permitting reform at the federal, state, and local levels. We need to accelerate efforts to speed resource addition. We need to reliably figure out how to integrate large loads. And we need to accelerate efforts to better coordinate the increasingly interdependent gas and electric systems that serve this country." ■

*—**Sonal C. Patel** is a POWER senior editor.*



4. Winter Storm Fern produced the highest seven-day rolling average of total U.S. lower-48 natural gas demand on record at 167 billion cubic feet per day (Bcf/d), with demand staying above 160 Bcf/d for 10 consecutive days. Courtesy: American Gas Association analysis of S&P Global Energy, Energy Information Administration, and Argus Media data, as of April 10, 2026

From Tail Risk to Design Baseline: How the Grid Is Adapting to Extreme Heat

System planners and grid operators are treating extreme heat as an assumed operating condition given new pressures, including drought, demand growth, and fuel concerns. Will it be enough?

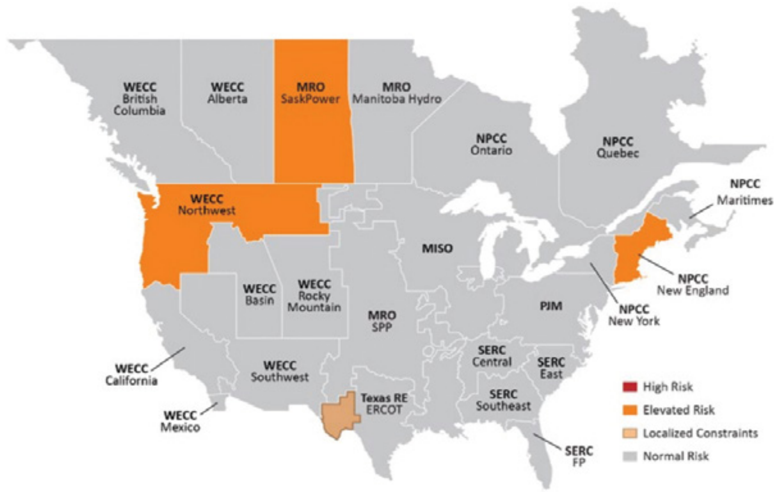
Sonal Patel

For decades, the U.S. power system treated extreme heat as a tail risk, managed through seasonal readiness—something for which to prepare. But hotter conditions are now arriving earlier and lasting longer, prompting system planners and grid operators to treat extreme heat as a design baseline—an assumed operating condition.

The U.S. Energy Information Administration's (EIA's) May 2026 Short-Term Energy Outlook, for example, projects roughly 1,610 cooling degree days (CDDs) nationwide this year—the standard industry measure of air-conditioning demand—4% above 2025, with the third quarter alone running 8% above the same period last year and 5% above the ten-year average. The North American Electric Reliability Corporation (NERC), the bulk power system's designated reliability entity, has begun flagging the overlap of early-summer heat with spring maintenance outages as a recurring concern, alongside wide-area heat events that NERC names as a primary reliability risk for summer 2026, on par with generator outages and fuel supply.

Yet every concern about extreme weather appears rooted in the grid's overall health—particularly its physical fabric: whether existing wires, transformers, and substations can withstand hotter conditions on top of the soaring load growth and aging infrastructure already straining the system.

Among several adaptive measures of note, utilities are now rating their transmission lines hour by hour against ambient temperature rather than against the once-a-season nameplate values they used for decades. High temperatures, meanwhile, threaten to accelerate wear on distribution and substation transformers, aging assets already in short supply and difficult to replace. On a larger systems level, operators are bracing for peaks that now arrive later in the evening, after solar output diminishes. Utilities are also tracking insulator faults hundreds of miles downwind of any fire line, where wildfire smoke deposits conductive particulates on high-voltage equipment, which raises fault risk on otherwise clear days.



Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

1. NERC's 2026 Summer Reliability Assessment identifies three elevated-risk areas for Summer 2026—NPCC–New England, MRO–SaskPower, and WECC–Northwest—where operating reserves could be insufficient under above-normal conditions. The assessment also flags a localized constraint in western ERCOT, where rapid load growth and transmission limits could bind during high-demand periods. Source: NERC, 2026 Summer Reliability Assessment, May 2026

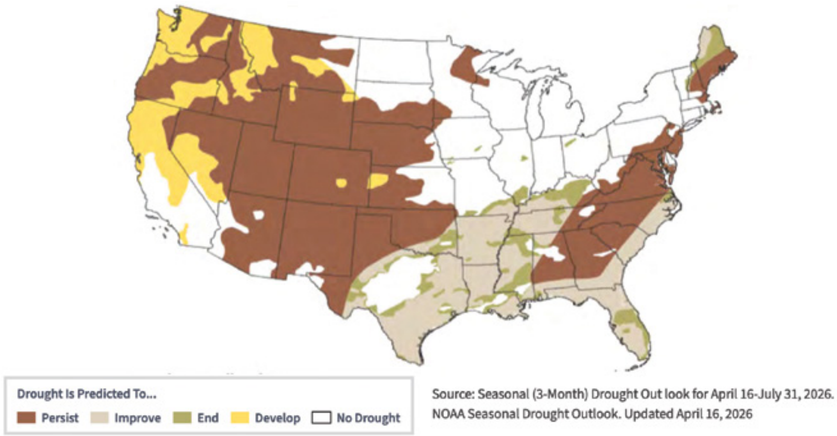
Summer 2026: A Better Position, but Not a Solved Problem

The 2026 season, at least, will begin in a somewhat stronger position than last summer. According to NERC's 2026 Summer Reliability Assessment, released on May 19, net internal demand—total demand minus controllable demand response available at the peak hour—is expected to rise 1.3%, or 10 GW, from 780 GW in summer 2025 to 790 GW in summer 2026, with peak demand growing in 19 of 23 assessment areas. The bulk power system will enter summer with more than 58 GW of new on-peak capacity, including 16.4 GW of solar, 14.7 GW of batteries, 6.7 GW of natural gas, and 1.6 GW of wind, alongside 19 GW from other resource additions and accounting changes. NERC, however, flags three subregions for elevated risk under above-normal or extreme conditions—Northeast Power Coordinating Council (NPCC)–New England, Midwest Reliability Organization (MRO)–SaskPower, and Western Electricity Coordinating Council (WECC)–Northwest—and identifies western ERCOT

(Electric Reliability Council of Texas) as a localized constraint where transmission limits in the Permian Basin could bind under high demand, even though the broader ERCOT system has the largest reserve margin in North America (Figure 1).

Meanwhile, the Federal Energy Regulatory Commission's (FERC's) 2026 Summer Energy Market and Electric Reliability Assessment, released on May 21, projects national wholesale electricity prices to average $46.81/MWh this summer, down 5% from 2025, though ERCOT, PJM Interconnection, and SERC Reliability Corporation will see increases of 11%, 5%, and 5%.

Still, both reports identify above-normal summer temperatures as the dominant operational concern, citing a National Oceanic and Atmospheric Administration (NOAA) forecast with a 61% chance of El Niño conditions and a one-in-four chance of a strong El Niño later this year. "Geographically widespread, high temperatures can intensify stress on the electric grid by reducing the ability of neighboring systems to exchange supply while they are simultaneously facing high demand," the FERC report says, adding that high temperatures also "increase transmission line losses and cause conductors to reach operating limits sooner under the combination of high load and high heat conditions, all of which increase the risk of outages."



2. NOAA's April 16, 2026, Seasonal Drought Outlook projects persistent drought across much of the West and parts of the Plains through late July, with drought development possible in portions of the Pacific Northwest. FERC's 2026 summer assessment warns that low inflows could affect up to 4,500 MW of Colorado River hydropower as soon as August. Source: NOAA Seasonal Drought Outlook; FERC 2026 Summer Energy Market and Electric Reliability Assessment

Drought, Demand, and Federal Intervention

The other dominant variable is drought. "Drought conditions impact 62% of the continental U.S. and are expected to expand this summer," FERC said, noting that Lake Powell is forecast to receive only 13% of average inflow—the lowest since Glen Canyon Dam began operating in 1964 (Figure 2). If conditions persist, FERC said, up to 4,500 MW of Colorado River hydropower could be affected as soon as August 2026, including the 2,000-MW Hoover Dam. NERC added that snowpack in the Pacific Northwest peaked at low elevations and melted early this year, which poses a problem for the region, whose generation mix is 55% hydropower. Canadian hydropower exports to the U.S. fell 28% in 2025 to 35.64 TWh, the lowest annual total since 2004, which threatens to reduce the flexibility available to the New York Independent System Operator (NYISO), ISO New England (ISO-NE), and the Midcontinent Independent System Operator (MISO).

And beyond hydropower generation, "low water volumes in summer 2026 in the greater Missouri and Mississippi River basins, following multiple consecutive years of low water flows, increase the risk of disrupted navigation, including for barges carrying coal to power plants," FERC noted. "Low water levels, the risk of saltwater intrusion, and increased water temperatures could prompt derating or forced outages of generators with once-through-cooling equipment on the affected rivers."

Finally, as both NERC and FERC flag, this summer's challenges may be compounded by a rapidly morphing demand curve—of load as well as fuel. NERC reported that aggregated peak demand across all assessment areas has increased by more than 11 GW since its 2025 summer assessment, exceeding the 10-GW year-on-year increase that preceded summer 2025. FERC, citing EIA data, projects total summer 2026 electricity consumption will reach 1,587 TWh, up 3% from summer 2025—the strongest year-over-year summer growth since 2022.

On the fuel side, FERC expects total U.S. natural gas demand to average 101.3 billion cubic feet per day (Bcf/d) this summer, with power burn remaining the largest demand sector. Power burn is forecast to average 44 Bcf/d for the full summer and 47.9 Bcf/d across July and August, while gross liquefied natural gas exports rise 10% to 15.8 Bcf/d. As *POWER* has reported, the Natural Gas Supply Association forecasts gas-fired power burn reaching 11 Bcf/d above the 2015 baseline this summer, driven by 7.9 Bcf/d of structural growth—much of it attributable to data center load, projected to grow 25% from 44 GW in 2025 to 55 GW in 2026—and 3.1 Bcf/d of economic dispatch.

But for hot-weather operations, the timing—not just size—of the peak also substantially matters. In Texas, the greatest-risk hour has been creeping closer to 9 p.m.—the late-evening ramp after solar output drops off, even as cooling and data center load remain. Compounding that stress, NERC said, large data centers and industrial facilities "pose risks of sudden load loss, which can trigger frequency disturbances, voltage instability, and cascading outages." While ERCOT has proposed ride-through requirements for large electronic loads (Nodal Operating Guide Revision Request [NOGRR] 282), those rules will not be in place for this summer, NERC said.

Weather-related reliability concerns, notably, have been the basis for a flurry of Department of Energy (DOE) Section 202(c) emergency orders, which use emergency authority under the Federal Power Act to keep an estimated 4,400 MW of coal and gas capacity online past planned retirement dates. As *POWER* has tracked, the affected capacity is concentrated in regions with the heaviest summer cooling loads and the largest hydropower flexibility losses. As of May, the DOE, for example, has extended its orders for the 1,560-MW J.H. Campbell coal plant in Michigan through Aug. 16 and the 760-MW Eddystone Units 3 and 4 in Pennsylvania through Aug. 22 to cover peak demand in MISO and PJM. It also added a new order for Wagner Unit 4 in Maryland through Aug. 19, and left earlier orders covering the Centralia plant in Washington—in NERC's elevated-risk WECC–Northwest subregion. The current emergency orders suite also covers Schahfer and F.B. Culley, both in Indiana, and Craig Station Unit 1 in Craig, Colorado, in place through staggered dates in June.

Rating Transmission for Heat

Physical stress to the grid is perhaps most worrisome during extreme heat to the transmission system. High-voltage lines tolerate the heat generated by their current by dissipating it to the surrounding air, but when ambient temperatures rise and the wind drops, lines have less capacity to dissipate that heat. Overheated conductors can sag toward objects on the ground and short out, or "anneal"—meaning they permanently lose the tensile strength needed to stay taut between towers. For decades, operators have managed that risk by setting conservative once-a-season nameplate ratings and redispatching generation when lines approached those ratings, but it has resulted in chronic underutilization of the existing transmission fleet on most days of the year.

FERC's Order 881, a 2021-finalized rule that took effect in July 2025, requires transmission providers to use ambient-adjusted ratings (AARs)—line ratings that update hourly based on actual and forecast temperatures, with hourly forecasts required out to ten days, separate ratings for day and night, and updates triggered by every five-degree-Fahrenheit change in temperature. In March, PJM became the first regional transmission organization (RTO) to implement AAR after a multi-year effort. Its ratings now adjust hourly across 47 regional weather-forecast zones inside the RTO's footprint.

"This was an enterprise-wide effort, involving a comprehensive stakeholder process, and Operations, Markets, and IT [Information Technology] working with three vendors on the design, deployment, and go-live event on March 4," noted Darlene Phillips, executive director of Operations Engineering Support. "PJM pushed the boundaries of technology and support that other RTOs will be able to follow, and our real-time monitoring and studies of the grid are now enhanced by ratings adjusted for ambient temperatures and the best available forecasts."

For now, the Southwest Power Pool also expects to implement AAR on Sept. 1, while MISO expects full compliance by the second quarter of 2028. Several utilities are also looking to run AAR this summer, including Tampa Electric, Duke Energy Florida, Southern Company, Dominion Energy South Carolina, Louisville Gas and Electric, Kentucky Utilities, Avista, Idaho Power, Public Service Company of New Mexico, and Portland General Electric.

3. During the June 2025 eastern U.S. heat wave, the Department of Energy issued a short-duration Section 202(c) emergency order authorizing Duke Energy Carolinas to operate roughly 8 GW of generation above environmental permit limits during the event. Duke's Lincoln Combustion Turbine Station, pictured here, was among the named facilities, alongside Marshall Station, Rockingham, Buck Combined Cycle, and Southern Power's Rowan and Cleveland stations. Lincoln's 402-MW Siemens Energy simple-cycle combustion turbine, synced in May 2020. Courtesy: Duke Energy

Dynamic line ratings (DLR), which use sensors to measure line temperature and ampacity in real time rather than relying on ambient forecasts, are moving from pilot projects toward corridor-scale deployment. Advanced composite-core conductor reconductoring offers another route, replacing existing conductors rather than building new lines. CTC Global told *POWER* the key appeal of advanced reconductoring lies in its ability to use existing rights-of-way and, in many cases, existing structures to increase transfer capacity faster than a rebuild.

Interregional transfer capability (ITC), which has been much called for, given the system's ability to move power reliably from one planning region to another, remains another potential solution. FERC's February 2026 report to Congress on NERC's Interregional Transfer Capability Study transmitted NERC's recommendation for 35,000 MW of technically prudent additions across 10 regions projected to have resource deficiencies in 2033. Several of the modeled deficiencies were tied to heat-wave weather years, including MISO-East, New York, California North, and New England. However, the report cautiously refrained from recommending specific projects and notes that it does not include an economic or cost-benefit analysis.

Order 1920's long-term regional planning framework provides a procedural vehicle for evaluating some of those needs. Whether cost allocation moves fast enough to turn reliability findings into funded projects remains unresolved. Capacity accreditation rules are also still being worked out. PJM's proposed Effective Load Carrying Capability (ELCC) accreditation reform at FERC Docket ER24-99, currently pending, will determine how solar, storage, and demand response receive capacity credit through the 2030s. The House High-Capacity Grid Act (H.R. 6633), introduced Dec. 11, 2025, notably, would direct FERC to establish a best-available-conductor standard for FERC-jurisdictional projects, but the bill remains in the House Energy and Commerce Committee.

Local Thermal Stress and Flexible Load

On distributed grids, meanwhile, heat exacts a slow toll on substation and distribution equipment that ultimately delivers power to the load. Insulation life in oil-filled transformers roughly halves for every 10C above rated winding temperature, and the IEEE C57.12.96 standard derates self-cooled distribution transformers 0.4% per degree when the 24-hour average ambient exceeds 30C. The DOE Large Power Transformer Resilience Report from July 2024 notes that large power transformers can be overloaded 10% to 20% above rated power, but that doing so accelerates insulation aging. The same report notes that transformer cooling capacity depends on both the operating load and ambient temperature, and that additional cooling—from larger tanks, radiators, fans, or alternating fans—can be designed into units for long-duration, high-temperature events.

Meanwhile, replacement timelines remain stretched. Wood Mackenzie's 2025 modeling concluded that announced North American manufacturing expansions—roughly $1.8 billion as of late 2025—should ease the large-power-transformer shortage by 2028, but distribution-transformer broker lead times remained 80–120 weeks through early 2026, with prices well above pre-2022 levels.

Wildfire smoke introduces another distinct distribution-system hazard that became more prominent during the 2024 and 2025 western fire seasons. Conductive particulates deposit on insulators along transmission corridors hundreds of miles downwind of any fire line, lowering flashover voltage and producing faults on otherwise clear days. A March 2026 review in Frontiers in Energy Research documented insulator flashover events linked to smoke deposition at distances well beyond traditional fire-impact zones.

On the ignition side, Pacific Gas and Electric's (PG&E's) 2026–2028 Wildfire Mitigation Plan, filed with California's Office of Energy Infrastructure Safety in April 2025, reported that its Enhanced Powerline Safety Settings (EPSS) program—which trips circuits at lower fault thresholds during high-risk conditions—contributed to a more than 72% reduction in California Public Utilities Commission (CPUC)–reportable ignitions on EPSS-enabled primary distribution lines in 2024, compared to the 2018–2020 average. EPSS now protects 1.8 million PG&E customers, and more than half of those customers experienced no outage while EPSS was enabled in 2024.

Generator-Side Preparedness

While generators don't have a hot-weather equivalent to NERC's cold-weather EOP-012-3 reliability standard, effective Oct. 1, 2025, the entity cautions in its latest summer reliability outlook that forced outage risk can rise during hot-weather operations because of plant age, operating patterns, and limited pre-seasonal maintenance availability. Its 2026 summer assessment further warns that early heat overlapping with spring maintenance can lower operating reserves, especially when hydro overhauls, contractor constraints, or major work at older generating sites delay return-to-service.

For now, state and market-level rules are filling some of the gap. ERCOT's weatherization inspection program is now a quantified enforcement record. As of October 2025, ERCOT had completed 4,079 cumulative inspections across four winter and three summer seasons, comprising 1,433 Resource Entity inspections and 2,646 Transmission Service Provider inspections. Summer-only cumulative totals climbed from 1,660 after summer 2023 to 2,902 after summer 2024 to 4,079 after summer 2025. ERCOT evaluates individual facility outages during peak demand periods and opens follow-up investigations to confirm preparation measures are in place. The agency assessed that the program has had "a significant positive impact on the reliability of the bulk electric system during winter and summer."

Efficiency measures are also continuing, including, for example, inlet air cooling (IAC) retrofits. For every 4-degree-F drop in inlet temperature, gas turbine output rises by about 1%, and above 90F ambient, utilities can see roughly 10% performance loss without mitigation, according to a July 2025 Burns & McDonnell engineering analysis. IAC retrofits can recover roughly 10% of the capacity loss imposed by high ambient temperatures on unmitigated combustion turbines, it suggests. Long interconnection queues, multi-year turbine lead times, and import tariffs on heavy equipment are pushing utilities to treat IAC as a near-term capacity play rather than an optional efficiency upgrade, it notes.

And as significantly, generator capability rules are also becoming more seasonal. PJM revised its Capacity Verification Testing rules effective June 1, 2025, requiring separate summer and winter tests, and ending the practice of correcting a summer verification test to winter conditions. Summer capability is now tied to generator-site ambient conditions coincident with the last 15 years of PJM summer peaks, while winter capability is tied to the corresponding winter peaks. ERCOT's summer weatherization rule is more prescriptive: under 16 TAC §25.55, generation entities must prepare for sustained operation up to the greater of the facility's prior maximum operating temperature or the 95th-percentile 72-hour temperature for its weather zone, document hot-weather critical components, and complete summer inspections by June 1 each year.

Still, plant-level capability filings suggest that, in some cases, extreme heat remains subject to licensing margins and operational constraints. Constellation in March 2025 sought a temporary Nuclear Regulatory Commission (NRC) license amendment for its Braidwood Station in Illinois to raise the nuclear plant's Ultimate Heat Sink (UHS) Technical Specification limit from 102F to 102.8F through Sept. 30, 2025. The filing cited historical summer conditions—including elevated air temperatures, high humidity, low wind speed, and the July 4–9, 2020, hot-weather and drought period—that had repeatedly challenged the existing limit. It also pointed to a Dec. 20, 2024, request for a permanent amendment to adopt a diurnal UHS temperature curve, reflecting that the cooling pond's thermal margin depends on peak water temperature, time of day, and recovery profile. Constellation said its analyses showed safety-related equipment would maintain its design function at the higher UHS temperature.

Digital Operations and Flexible Load

Solutions also extend into distribution-system operations and customer-side resources. Advanced Distribution Management Systems (ADMS) and Distributed Energy Resource Management Systems (DERMS) are the operational platforms connecting bulk-system conditions to local grid response, and utilities are deploying integrated versions of both at scale, including Southern California Edison's (SCE's) integrated Grid Management System and PG&E's ongoing three-release ADMS rollout through 2026. Those platforms increasingly anchor utility-managed electric vehicle (EV) charging programs like PG&E's WeaveGrid-operated EV Charge Manager, SCE's CPUC-approved ORCHARD program, and Con Edison's SmartCharge New York.

Finally, virtual power plants (VPPs) are the best-documented new category of demand-side flexibility heading into summer. The DOE's Pathways to Commercial Liftoff: Virtual Power Plants report estimates the U.S. installed base at 30 GW to 60 GW, with a 2030 target of 80 GW to 160 GW. A Rocky Mountain Institute analysis published May 14, 2026, described several program dispatches during summer 2025, including Sunrun's more than 340-MW residential battery dispatch on June 24, EnergyHub's 900 MW of peak load shed and 3.5 GWh shifted to off-peak hours, Uplight's 350 MW of flexible load managed, and a July 29 California Independent System Operator (CAISO) Demand Side Grid Support test that delivered more than 500 MW of demand relief during the late-afternoon net-load peak.

Demand response (DR) remains a crucial tool for extreme heat operations. PJM, for example, cleared its June 2025 heat wave—which drove a peak of 162,401 MW on June 24, the third-highest in PJM history—by deploying DR that reduced load by more than 4,000 MW at the most extreme peaks, with no firm load shed. ERCOT is taking a similar approach as summer load growth raises operating risk. In a December 2025 Grid Insights brief, ERCOT said its DR programs—Emergency Response Service (ERS), Load Resource Participation, and Voluntary Load Response—are designed to reduce load during periods of scarcity, including extreme weather events or unexpected generation or transmission outages. ERS participants must provide agreed-upon megawatts within 10 to 30 minutes when called. ERCOT also said it is reviewing existing DR tools and piloting Aggregate Distributed Energy Resources (ADERs), which aggregate distribution-connected sites that can respond to ERCOT dispatch instructions. ■

*—**Sonal C. Patel** is a POWER senior editor.*

Growing Grid Strategy: Undergrounding Power Lines to Withstand Weather

The power generation sector, including electric utilities and grid operators, recognizes the value of moving equipment underground to mitigate outages, lessen risks to assets, and reduce the chances of that equipment causing a wildfire.

Darrell Proctor

Electric utilities and power grid operators increasingly are looking at ways to diminish and avoid disruptions from extreme weather. The power sector also has experience with the financial impacts of wildfires, both with damage to assets and losses incurred when equipment is found liable for causing those events.

Undergrounding lines, in addition to enhancing safety, also can improve the performance of transmission infrastructure, by mitigating hazards such as impacts from trees and other vegetation. A report from the U.S. Department of Energy's (DOE's) Grid Deployment Office, along with Berkeley Lab in California, notes a "key advantage of underground transmission and distribution lines is substantially reduced vulnerability to disruption from extreme weather and wildfires [by preventing initial ignition as well as propagation], resulting in both reliability and resilience improvements." Several electric utilities and other agencies have noted that undergrounding offers protection against lightning, animal incursions, high winds (including thunderstorms, tornadoes, hurricanes, and derechos), and ice and snow. It also eliminates the chances of fallen power lines caused by auto accidents (Figure 1), or simply due to aging infrastructure.

Richard Gray, innovation director at S&C Electric Co., said there are structural designs that should be implemented to harden transmission lines and towers against threats such as high winds, and ice and snow. "Stronger structures help, but they're only part of the picture. You can design for higher wind or ice loads, but extreme events will still find weak points somewhere on the line," said Gray. "Even if you harden generation and transmission, it doesn't matter much if the distribution system isn't equally resilient, because that's what ultimately delivers power to the end user. Though it can be a large undertaking, one of the most effective ways to protect against extreme weather is to move distribution systems underground."

1. *A single vehicle impact can topple a pole, drop live conductors into the street, and cut power to an entire neighborhood. Undergrounding removes the target from the roadside. Courtesy: photovs / Envato Elements*

"Undergrounding ... should certainly be more proactive rather than reactive because the costs become even higher the longer we wait [to underground]," said Tziporah Feldman, director of policy and research for Scenic America, a nonprofit group "that helps safeguard America's scenic qualities." The group notes several legislative wins, including "successfully advocating for federal support for utility undergrounding in the Infrastructure Investment and Jobs Act of 2021, including an amendment to the Stafford Act to allow FEMA [Federal Emergency Management Agency] funds to be used for undergrounding and a new $5-billion resiliency grant program."

Feldman pointed out that while undergrounding of electric power infrastructure can be costly, not considering the practice can come with even more financial risk, particularly from wildfires. "For instance, the January 2025 Southern California wildfires were believed to be caused by an SCE [Southern California Edison] transmission line," said Feldman. Attorneys representing victims of the fires filed lawsuits against the utility, and estimated the damages from the wildfires at more than $250 billion. Feldman said utilities concerned about the cost of undergrounding power equipment should do "more work ... to take into account wildfire costs."

Robert McClellan, transmission team leader at Stantec, told *POWER*, "Undergrounding is a useful tool for wildfire protection but like all tools, there is a time and place for them to be used most effectively. Working to build a power system that uses the various advantage of the dif-

2. Cables installed in buried conduit are shielded from wind, ice, vegetation, vehicles, and ignition sources—trading upfront construction cost for decades of reduced outages and avoided wildfire liability. Courtesy: VidEst / Envato Elements

ferent methods we have available is the cornerstone of intelligent engineering."

Said McClellan, "An electric utility should be as proactive as they can when undergrounding transmission lines. It can be a monumental task to try to convert from overhead to underground but the risk reduction is vital when considering cost to life."

Undergrounding Techniques

Trenching and tunneling are two of the construction techniques for undergrounding of transmission lines. Both involve plenty of planning, starting with a site assessment that includes soil examination, mapping of existing utilities, and plotting the path of the trench or tunnel.

A popular trenching technique includes digging and preparing a site that is wide enough for cables and supporting infrastructure (Figure 2), and also an appropriate depth below ground. The floor of the trench is prepared with sand or cement materials, using tools such as power rollers. The power lines and other infrastructure components are placed in the trench; the trench is then backfilled or covered with a protective and thermally stable cover.

Tunneling is used in places where trenching and other burying techniques are problematic. This technique involves the use of boring and drilling machines to create tunnels that will house transmission lines. It can include directional drilling, with various tunneling techniques employed to scale tunnel depths and diameters appropriately for the type of infrastructure being moved underground.

Specialized materials are needed to protect underground power lines. High-density polyethylene (HDPE) and polyvinyl chloride (PVC) conduits can be used

3. GE Vernova's SPEEDWORM technology installs conduit and cables for underground distribution power lines in a single step, mimicking the movement of earthworms and tree roots to install 1,000 feet of cable and conduit in about two hours, according to the company. Courtesy: GE Vernova

to prevent corrosion, water ingress, and mechanical damage. These materials also provide underground equipment with durability to protect against environmental factors, and mitigate possible damage from digging accidents.

The DOE in 2024 announced investment of $34 million through its Advanced Research Projects Agency-Energy (ARPA-E) program to develop advanced, low-cost, and rapid tunneling technologies for burying power lines. It selected projects as part of the Grid Overhaul with Proactive, High-speed Undergrounding for Reliability, Resilience, and Security, or GOPHURRS, program. Among the awarded projects was a subterranean robotic tunneling construction tool developed by GE Vernova Advanced Research in New York. The tool, known as SPEEDWORM (Figure 3), would dig and install conduit and cables for underground distribution power lines in a single step, mimicking the movement of earthworms and tree roots to install 1,000 feet of cable and conduit in about two hours.

William Tan, lead researcher on the GE Vernova project, last year said SPEEDWORM uses advanced state-of-the-art localization techniques, which allow for near-real-time subsurface positioning. Tan said the device's long tail has metal muscles, which he said inflate and deflate in "peristaltic motion," a reference to the way food moves through a human's digestive tract. Tan in a news release said that particular motion moves the mechanical worm forward while compacting the soil around it, akin to a finger gouging into damp sand. Other DOE-awarded projects feature the use of artificial intelligence and sensors to facilitate more rapid construction of underground power distribution systems.

Robert Wall, associate principal at Perkins&Will, an architecture and design group, said, "Where it's feasible, putting transmission infrastructure below ground is one of the most effective ways to protect it from weather-related damage." Wall added, "One of the most impactful first steps for any utility—or any type of physical asset for that matter—is developing a digital twin of its system. Digitization gives operators a much clearer picture of how assets perform and how best to plan for hardening, expansion, and future demand. From there, prioritizing underground transmission and distribution where possible makes a big difference in reducing weather exposure. Just as important is ongoing monitoring of both assets and environmental conditions so decisions can be proactive rather than reactive."

Mitigating Wildfire Risk

Investigation and analysis of several major U.S. wildfires in recent years identified overhead power lines as the ignition sources, including in California, Hawaii, and Texas. California in the wake of several destructive and deadly fires established regulatory mandates that require the state's largest utilities to submit 10-year undergrounding plans prioritized by wildfire risk.

Pacific Gas and Electric (PG&E), which filed for Chapter 11 bankruptcy in 2019 due to more than $30 billion in liabilities from wildfires in California in 2017 and 2018, has one of the most ambitious undergrounding programs. The utility emerged from bankruptcy in summer 2020, with a reorganization plan focused in part on safety initiatives. The utility recently said it has completed installation of more than 1,200 miles of underground power lines, and is targeting hundreds more miles this year. The utility on May 1 of this year said it has "installed more than 1,640 total miles of system upgrades [including strong poles and covered powerlines] since we launched our Community Wildfire Safety Program in 2018. This year, we plan to complete 314 miles of system upgrades." The utility has a long-term goal of undergrounding 10,000 total miles of its transmission system.

San Diego Gas and Electric (SDG&E) is among several California electric utilities moving overhead power lines underground in areas that are most at risk for wildfires (Figure 4). It also is among several utilities, both in California and other states, utilizing public safety power shutoffs (PSPS), in which a utility proactively shuts off power to an area when weather conditions increase the risk of wildfires. The company calls its program "Strategic Undergrounding," and says it is among several projects in the utility's Wildfire Mitigation Plan. SDG&E said that program aims to reduce the impacts of PSPS on facilities such as fire stations, medical centers, schools, and libraries, among other sites.

4. A wooden pole in dry grass can be both a fire starter and a fire victim. Undergrounding ends both roles: no sparks to ignite the field, no charred poles to replace when the smoke clears. *Courtesy: Galyna_Andrushko / Envato Elements*

SDG&E said, "The Strategic Undergrounding Program will provide heightened wildfire resiliency and electric reliability by undergrounding electric distribution lines near key community facilities. Removing overhead power lines and placing them underground helps remove the risk of sparking fires during adverse weather. It also enables the power lines to remain energized during PSPS, which reduces the impact of power outages on fire-prone communities.

"After individual circuits or projects are undergrounded, the SDG&E overhead power lines and equipment will be removed, but what is left may vary depending on the power line configuration," the utility said. "For example, if poles are also used by other utility providers, such as telephone or cable, and are required by those service providers, then the poles will remain to support those services." SDG&E began work on its Strategic Undergrounding Program in 2019; the utility expects to continue work through 2032, with a goal of undergrounding about 1,500 miles of power lines.

The California Independent System Operator (CAISO) recently selected LS Power Grid California (LSPGC) to finance, build, own, operate, and maintain a new 230-kV underground transmission line. The project is aimed at strengthening power infrastructure and improving grid reliability across the San Francisco Bay Area. Officials said the line, located across about seven miles, will connect Silicon Valley Power's Northern Receiving Station Substation to PG&E's San Jose B Substation, building on the work of LSPGC's Power Santa Clara Valley and Power the South Bay projects, which are expected online in 2028. The 230-kV installation was approved in CAISO's 2024–2025 Transmission Plan. The line has an estimated cost of $150 million to $200 million, and is targeted to enter service by June 2030.

"We appreciate CAISO's continued confidence in LS Power through this competitive selection," said Paul Thessen, president of development for LS Power, in a statement. "We have consistently delivered on our commitments in a timely manner, and this project builds on our growing footprint in California and extensive experience successfully developing transmission projects across the country. We look forward to working with our partners to deliver this critical infrastructure for the Bay Area."

Thessen added, "CAISO is at the forefront of competitive transmission planning, and its transparent and deliberate annual planning process ensures that electricity consumers benefit." After the line is energized, PG&E is expected to own, operate, and maintain the project, which will support energy demand growth in the San Jose area. LSPGC currently has one asset in service—the Orchard Substation in Fresno County—along with five additional transmission projects in development across the state, including two in the Bay Area.

Weighing Pros and Cons

Xcel Energy, the largest utility in Colorado—another state increasingly prone to wildfires—has noted that putting power lines underground is not always the best solution, in part because underground lines are still at risk of outages, and repairs to underground lines can take longer to fix. The utility also notes that "constructing and installing underground lines can cost 5–10 times more than overhead construction practices."

Xcel, though, is actively investing in undergrounding power lines (Figure 5) to improve reliability and wildfire safety. Robert Kenney, the utility's president in Colorado, earlier this year said Xcel has plans to bury about 50 miles of distribution lines in high-risk Colorado areas over the next few years. That includes Boulder County, where memories are still fresh of the devastating Marshall Fire in late December 2021, which destroyed nearly 1,100 homes in the towns of Superior and Louisville, north of Denver and just south of Boulder.

The city of Boulder has completed several undergrounding projects after the Marshall Fire, and is working on several more. The Colorado Public Utilities Commission in August of last year approved Xcel's 2025–2027 Wildfire Mitigation Plan, which the utility said would allow it to "expand the scope, pace, and scale of our wildfire mitigation work." That includes work in and around Boulder.

Lisa Andersen, a spokesperson for Xcel, told *POWER*: "Xcel Energy uses undergrounding as one of several tools to strengthen the grid and reduce wildfire risk; however, factors such as cost, terrain, and permitting constraints are taken into account. In Colorado, there are approximately 19,000 distribution line miles underground, including about 4,000 distribution line miles in high-risk areas—this represents about 50% of our system in the state. We have far less

5. Xcel Energy has buried power lines in neighborhoods across its service territory, including in Colorado. The utility uses undergrounding as one of several tools to support the power grid and reduce the risk of wildfires. Source: POWER

transmission lines undergrounded due to several of the listed factors."

Andersen added, "Our strategy currently focuses on targeted undergrounding in areas where it delivers the greatest benefit—such as locations with elevated wildfire risk or where reliability can be significantly improved. In Colorado, our Wildfire Mitigation Plan includes plans to underground about 50 miles of distribution line in high-risk areas, alongside other system hardening upgrades by the end of 2027. The cost of this work is estimated to be $80.3 million in capital expense, or $3.12 million per mile.

"Undergrounding can reduce wildfire risk and protect infrastructure from weather impacts, but it can be more complex to build and maintain," said Andersen. "Projects require coordination with other utilities, extensive permitting, and must account for terrain, environmental protections, and existing underground infrastructure. For these reasons, Xcel Energy evaluates undergrounding on a case-by-case basis and balances it with other solutions—such as stronger poles and wires, covered conductors, and advanced grid technologies—to deliver the greatest reliability and safety benefits for customers at the lowest cost."

Xcel also is replacing and upgrading an underground line running from central to southeast Denver. The project, underway since September 2025 and expected to be completed next year, involves replacing the six-mile-long 230-kV Leetsdale-Monroe-Elati underground transmission line. The line runs through an area that has experienced significant growth in recent years, which has increased electricity demand.

Legislative and Other Initiatives

Virginia lawmakers this year asked state utility commissioners to study the undergrounding of electrical transmission lines. Officials said the move was prompted by anticipated power demand from data centers; Virginia is a hotbed for U.S. data center development. Scenic America, in partnership with Scenic Virginia, advocated for the legislation as part of a broader effort to promote resilient, reliable, and visually responsible infrastructure.

"This study will help bring greater clarity to the long-term value of undergrounding. When you account for reduced maintenance, fewer outages, and increased resilience, undergrounding often proves to be a smart investment," said Feldman. "We commend the Commonwealth of Virginia for committing to evaluate these benefits in a rigorous, data-driven way."

New Jersey legislators also this year introduced a new bill that would require electric distribution lines to be placed underground in areas affected by severe weather or natural disasters. Proponents said the measure would improve electricity reliability and enhance safety. The legislation would mandate that state public utility officials establish standards for this underground installation wherever feasible, primarily in areas that have experienced, or would be prone to, severe weather or natural disasters. The measure defines "Major Catastrophic Events," such as a severe storm, flood, or earthquake, that causes widespread power outages affecting at least 10% of electricity customers.

Arizona-based Tucson Electric Power (TEP) has outlined "Five Things to Know about Putting Power Lines Underground," with the utility noting—as have other electricity providers—that cost is always part of the equation. TEP, in answer to a question about why it doesn't bury all its lines underground, said, "The short answer is that it's more expensive—much more, for higher-voltage lines—and doesn't really improve reliability. While underground lines are protected against certain types of damage, they're more vulnerable in other ways that can lead to longer outages."

TEP on the company's website noted, though, that, "Of the nearly 8,000 miles of lower-voltage distribution lines that deliver electricity to local homes and businesses, more than half—about 4,800 miles—are below ground. In most cases, the additional cost of underground installation was paid by developers or property owners to avoid increasing the costs passed along in rates to all TEP customers." Of note, though, is that the utility said it does not put transmission lines underground. "All 2,200 miles of our higher-voltage lines are overhead because building them underground can dramatically increase costs. It can cost significantly more to install facilities underground, and that premium is even greater for higher-voltage projects.

"In part, that's because transmission lines conduct energy flow at higher amperages than distribution cables," wrote TEP. "Since underground lines can't release heat the way overhead lines can, that excess heat must be managed to avoid overloads. This requires the use of higher-cost conductors and other insulating infrastructure. Higher costs also typically reflect greater civil engineering expenses, additional ground disturbance and additional labor."

TEP wrote that "installing lines underground can more than double the cost of a distribution project and might increase the cost of a transmission line project by 10–20 times. Our latest study of TEP's proposed Midtown Reliability Project, for example, indicates that overhead construction of this 138-kilovolt line would cost approximately $1.2 million per mile. Underground construction, though, would cost between $15.2 million and $26.7 million per mile. Both estimates reflect current costs and exclude the cost of necessary land rights."

The TEP Midtown Reliability Project is a $22-million infrastructure initiative that was approved in 2024, with a goal of modernizing the power grid in Tucson by 2027. Mike Nitido, TEP's director of Transmission and Distribution Planning and Business Operations, said the utility's most recent five-year capital budget forecast calls for investing $3.45 billion through 2028 on new generation, and transmission and distribution system assets. "Our goal is to provide safe, reliable, and increasingly clean power, while also ensuring it remains affordable," Nitido said. "It requires a constant balance."

Evaluating Costs

Feldman of Scenic America told *POWER*, "It is a myth that undergrounding [of power lines] is up to 14 times higher" than installing traditional overhead lines. "The true cost differential [upfront cost] is two to three times higher, which has been shown with real programs like Dominion [Energy] and FPL [Florida Power and Light]. The 10-to-15 times higher figure is likely from an older study in which all lines were undergrounded, not strategic undergrounding. Economic analysis has shown that undergrounding costs break even if a [overhead] line is downed once in a 10-year period, and is economically favorable if downed more than once."

Dominion said its Strategic Underground Program, launched in 2014, is designed to identify those overhead lines most prone to outages, and then work with property owners to move those lines underground. "Using a data-driven process, we continually analyze the performance of tap lines over a 10-year period. Those most prone to outages will be considered for placement underground," the utility said. "Trees are the number one cause of power outages. Tap lines, the overhead wires that go into neighborhoods, typically sustain the most damage during storms and require the highest number of repairs." The utility notes, "While outages may still occur, undergrounding the most frequently damaged power lines will increase the overall reliability of our distribution system."

> ***"Horizontal directional drilling, plasma boring technology, ground level distribution systems, and co-location on existing rights-of-way allow utilities to adapt to diverse conditions while reducing installation costs."***
>
> —Tziporah Feldman, director of policy and research for Scenic America

FPL's Storm Secure Underground Program (SSUP), also initiated a few years ago, proactively replaces overhead neighborhood power lines with underground cables, which the utility said improves reliability against severe weather and reduces outages caused by vegetation. FPL said the program uses directional boring to minimize property damage, with projects selected based on historical, data-driven storm outages.

FPL said it has invested nearly $4 billion since 2006 to strengthen its grid; the utility said, "a significant portion of which is dedicated to undergrounding power lines to improve storm resilience. While total long-term undergrounding costs have been estimated at up to $35 billion, FPL has moved over 50% of its distribution system underground as of mid-2025."

Feldman said there are many factors that make undergrounding feasible over time, including:

- *Climate Resilience.* "Undergrounding is essential in the face of a changing climate," said Feldman. "More severe storms, larger wildfires, and more frequent hurricanes highlight the vulnerabilities of overhead lines."
- *Reduction in Vegetation Management Costs.* "Undergrounding eliminates the need for extensive vegetation management, a practice that costs U.S. utilities $33 billion annually," said Feldman. "Clearing vegetation around transmission lines can also create soil runoff, which can contribute to pollution and contamination when chemicals are used."
- *Reduced Maintenance Costs and Longer Lifespan.* "Underground lines have significantly lower maintenance costs compared to overhead systems. Maintenance expenses are reduced by up to 80% due to fewer truck rolls," said Feldman. "Modern technology has helped underground infrastructure last two to three times longer than overhead assets."
- *New Technology and Methodology.* "Advances in technology and strategic planning have made undergrounding more feasible and cost-effective," said Feldman. "Horizontal directional drilling, plasma boring technology, ground level distribution systems, and co-location on existing rights-of-way [ROWs] allow utilities to adapt to diverse conditions while reducing installation costs."

"Additionally, there is a world of opportunity for transmission undergrounding cost-saving measures when highway and railroad ROWs are utilized," said Feldman. "The Federal Highway Administration has found that co-locating utilities in the highway ROW is in the public interest and is permitted under federal regulations. ROW undergrounding solves logistical problems with transmission buildout such as avoiding the difficulty of building entirely new overhead corridors, enables the efficient delivery of energy to power electric vehicles, provides new revenue streams for transportation agencies, reduces environmental impact, reduces the need for lengthy and costly siting/rerouting studies, and curtails the risk of organized public opposition," said Feldman.

Feldman also said utilities can lessen the cost of undergrounding with lower insurance premiums, and less exposure to liability. Feldman also noted the aesthetic value of putting transmission lines underground.

"Overhead wires create visual pollution that detracts from the intrinsic beauty of the landscape, which is critical to physical and mental health, and the impact is once again particularly profound in disadvantaged communities. People are drawn to live and work in places that are visually appealing, as these environments foster a sense of pride, well-being, and community connection," said Feldman. "Undergrounding can enhance the visual landscape and create more desirable spaces for residents and businesses alike." ■

*—**Darrell Proctor** is a senior editor for POWER.*

Advanced Weather Forecasting: How Sub-Kilometer Models Are Reshaping Utility Risk and Wildfire Decisions

As fire-weather risk expands beyond California, utilities are turning to sub-kilometer, asset-level forecasts to support public safety power shutoff decisions they can defend in front of regulators.

Aaron Larson

When the National Weather Service (NWS) issued routine convective outlooks on the morning of May 27, 2025, public guidance for the Houston metro called for widespread 30 to 40 mph wind gusts, with isolated pockets reaching 45 to 60 mph. CenterPoint Energy's meteorology team was looking at a different picture. A sub-kilometer model from Climavision was flagging slow-moving thunderstorms with gusts above 50 mph and identifying a specific corridor—Greenspoint, The Woodlands, Humble, Kingwood, and Galveston—where the worst wind would land. The forecast was specific enough, and confident enough, to act on. CenterPoint predeployed 1,300 crews at midnight rather than leaving them on standby. Observed gusts came in at 60 to 70 mph in that exact corridor. Peak outages were held to roughly 167,000 customers. By the end of the day, the utility was 99% restored.

That kind of decision—pulled forward into the hours before a storm hits, anchored on a forecast specific enough to defend in front of a regulator afterward—is what utilities increasingly want from the advanced-forecasting layer they sit on top of public weather products. And it isn't only a Western U.S. story anymore. Drought-stressed fuels in the Carolinas and Tennessee, frontal-passage drying across the New Jersey Pinelands and Long Island, and damaging convective downbursts across the central U.S. (Figure 1) are pulling fire-weather risk into territory where most utilities historically did not plan for it.

Three providers *POWER* spoke with—Climavision, Meteomatics, and Technosylva—describe distinct technical approaches but converge on the same practical observation: the resolution, refresh rate, and forecast horizon utilities now require for wildfire and severe-weather decisions are well past what public products deliver, and the gap matters most in the two- to three-day window when public safety power shutoffs (PSPSs) and crew-mobilization decisions actually get made.

1. Damaged transmission lines on May 16, 2024, near Highway 99 in Cypress, Texas, after a derecho with 100-mph gusts swept through the Houston metro. Wind events of this scale now drive utility wildfire decisions in regions that did not historically carry fire-weather risk. Courtesy: Marie D. De Jesús/ Houston Landing

The Resolution and Refresh-Rate Story

The clearest way to understand the gap between public forecasts and what advanced providers are now selling is in two numbers: spatial resolution and update frequency. The National Oceanic and Atmospheric Administration's (NOAA's) High-Resolution Rapid Refresh (HRRR) model, the workhorse short-range product most utility meteorology desks consult, runs at roughly 3-kilometer (km) grid spacing with hourly updates but only out to 18 to 48 hours.

Climavision runs its HI-RES physics-based model—a derivative re-engineered from the HRRR lineage—at 2 km across the continental U.S. with an optional 670-meter inset over a customer's service territory, refreshing every six hours and extending out to a full seven days. Climavision Founder and CEO Chris Goode summarized the difference as "customized physics, proprietary observations, and a higher-resolution inset that public or private models simply do not produce." For point-specific forecasts at substations and key circuit segments, the company's Point Forecast Solution updates at 15-minute intervals out to 15 days, blending output from more than 100 underlying models with machine-learning bias correction trained on local observations.

Meteomatics takes a different but parallel approach. Its US1k model runs at 1-km resolution with hourly updates, ingesting weather data from more than 110 sources, including aircraft, ground stations, drones, radars, and satellites. Among those sources is the company's proprietary Meteodrones—weather drones capable of flying up to 6 km above mean sea level, sampling layers of the lower atmosphere where conventional radiosondes only fly twice a day. Chris Hyde, a senior account executive and meteorologist at Meteomatics, framed the resolution argument bluntly: standard global model resolution is 20 km, leading U.S. solutions reach 9 km, and "Meteomatics' US1k model has a resolution of 1 km and updates every hour."

Technosylva focuses specifically on fire behavior modeling rather than general weather forecasting. Indran "Indy" Ratnathicam, chief growth officer at Technosylva, told *POWER* the company operates its own continental-scale Weather Research and Forecasting (WRF) implementation at 2-km resolution, optimized for predicting fire and extreme weather conditions. That weather model feeds into hourly asset-level fire-risk and danger forecasts that look five days into the future. Ratnathicam said the company runs roughly 9 billion simulations a day across customer territories, drawing on more than 20 years of training data.

The Two-to-Three-Day Decision Window

Resolution and update frequency matter operationally because of a specific window. PSPSs are typically called two to three days in advance. "Once dangerous fire weather shows up in the short-range forecast, the window to do customer notifications, mutual aid staging, and regulatory paperwork well has already closed," Goode said.

Public HRRR's 18- to 48-hour ceiling sits inside that window, not ahead of it. That is the structural gap advanced providers are trying to close. Meteomatics shared one quantitative anchor from its work with NorthWestern Energy: between Oct. 31 and Nov. 3, 2025, the platform captured 16 wildfire-risk alerts across 16 sub-regions of NorthWestern's 626 high-risk weather zones, with an average lead time of 46 hours. That converts a reactive de-energization into a planned one—and converts a defensive scramble into something a utility can document and explain.

The other half of the decision-window story is the value of correctly placing risk that doesn't materialize where the public guidance puts it. In Climavision's Winter Storm Fern case from late January 2026, the company's HI-RES model issued three days ahead placed the heaviest icing well north of CenterPoint's service area. That precision, Goode said, allowed the utility to keep its crews staged for localized outages rather than mobilizing toward a region that ultimately wasn't badly affected—"a quieter outcome than May 27, but a meaningful one for cost discipline and crew readiness."

Wildfire Risk Beyond the West

A strong theme across all three providers is geographic expansion. Both Climavision and Meteomatics emphasized that demand for wildfire-aware forecasting has moved well past California and the Northern Rockies. Goode named drought-stressed fuels in the Carolinas and Tennessee, frontal-passage drying in the New Jersey Pinelands and on Long Island, and convective downbursts across the central U.S. that drop lines into dry vegetation. Hyde made the same point about expanding wildfire-mitigation focus into "states such as New Jersey, Georgia, and Florida."

The 2024 derecho events are the most cited examples of how that expansion plays out for utilities operating outside the traditional fire-weather geography. Climavision said its HI-RES model flagged the severe-wind threat from the May 16, 2024, Houston derecho, which produced 100-mph gusts, in consistent runs eight hours ahead of public models, and resolved the 80-plus mph wind threat from the July 15, 2024, northern Illinois derecho 12 hours ahead of the public HRRR—events that knocked transmission out for days and dropped distribution lines into drought-stressed fuels in regions that would not have been on a five-year-old wildfire-risk map.

Custom Thresholds and Utility-Defined Zones

A second technical theme worth pulling out is the move away from vendor-defined alert defaults toward zone-specific, utility-owned thresholds. The CenterPoint implementation runs distinct alert streams for temperature, sustained and gust wind, precipitation, severe storms, and icing—each tied to the 13 operational regions CenterPoint uses for situational awareness. NorthWestern Energy's 626 high-risk weather zones each carry their own thresholds. "Each weather monitoring zone's thresholds are customized to that area," Hyde said, "so there are no general or overarching thresholds."

Compound conditions are now standard. Goode described fire-weather alerts that pair a relative-humidity floor with a wind threshold, often gated by an antecedent dry-spell or temperature condition; blow-down alerts on saturated ground that pair gusts with soil moisture; severe-storm alerts that pair a severe-storm index with precipitation in the same forecast hour; and winter alerts that combine temperature, precipitation type, and accumulation across a defined window.

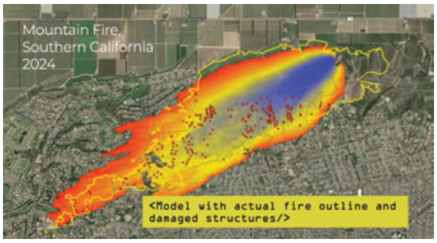
Both Climavision and Meteomatics emphasized that utility-owned observation networks now feed back into the model. Climavision assimilates more than 150 surface stations from CenterPoint into its 670-meter Houston inset; Meteomatics described ingesting customer station data for local calibration as a baseline feature. The distinction matters because, as Goode put it, the goal is "ground truth they already trust" turned into "a sharper, more accurate forward-looking forecast"—rather than asking the dispatch desk to reconcile a vendor product with sensor data the utility already has on the ground.

2. *Smoke from the Marshall Fire rises over Boulder County, Colorado, on Dec. 30, 2021. Driven by hurricane-force winds, the fire destroyed more than 1,000 homes in Louisville and Superior in a matter of hours. Courtesy: Patrick Cullis*

The Urban Conflagration Problem

A separate technical gap, and one that doesn't show up in standard wildfire models at all, is what fire does once it reaches a populated area. Most wildfire-spread modeling relies on the federal LandFire dataset, which classifies urban areas as "non-burnable." Standard models using LandFire as input show little or no fire spread through urban environments—exactly the opposite of what occurred in the 2023 Lahaina Fire on Maui, the January 2025 Palisades Fire in Los Angeles, and the 2021 Marshall Fire in Boulder County, Colorado, which destroyed roughly 1,000 homes in Louisville and Superior (Figure 2).

Ratnathicam said Technosylva has



3. Pre-fire simulation from Technosylva's urban conflagration model overlaid on the 2024 Mountain Fire in Southern California, with the actual fire perimeter in yellow and damaged structures marked in red. Courtesy: Technosylva

built a comprehensive new fuel-classification dataset specifically for urban environments, including structures, and redesigned its rate-of-spread calculations for urban areas based on hundreds of historical urban fires. The company has also added what it calls a Dynamic Building Loss Factor, which captures structure-to-structure spread, predicts structural losses, and accounts for how fire navigates large gaps of less-burnable areas like streets and how individual homes contribute to and accelerate spread once ignited.

The model combines physical and empirical methods, with a probabilistic layer derived from running scenarios across two decades of training data. Sources include the National Interagency Fire Center, the U.S. Forest Service, satellite thermal observations, infrared fire-progression perimeters, low-Earth-orbit and space-based light detection and ranging (LIDAR), weather stations, and a number of private datasets.

The urban conflagration capability is being built into Technosylva's existing utility-facing products this year (Figure 3)—both the planning-tier products that support grid hardening, vegetation management, and capital prioritization; and the operational-tier products that deliver hourly asset-level fire risk five days out and integrate into PSPS, enhanced powerline safety settings (EPSS), and fire-agency coordination workflows. "It isn't a separate offering bolted onto our existing models—it's built into them," Ratnathicam said.

Physics, AI, and the Documentation Tail

A subtler theme—but one with real implications for utility executives carrying regulatory and legal exposure—is the divide between physics-based and artificial intelligence (AI)-native forecasting models. AI weather models from major tech companies have advanced rapidly over the past two years, often outperforming traditional numerical weather prediction on benchmark tests. But for utilities, raw skill is not the only criterion.

"A growing share of weather products in the market is AI-native—useful and improving quickly, but opaque by design," Goode said. "When an operator has to explain to a regulator or a court why a particular de-energization, restoration timing, or staging decision was made, 'the AI model said so' is a difficult position to defend." Climavision's HI-RES is built on physics-based forecasting, with machine learning layered on top to sharpen specific components rather than replace them; the company describes those layers as auditable.

Hyde made a similar point from a different angle: "Although there is a lot of hype around AI in weather forecasting, those models still need time to prove its accuracy." High-resolution physics-based modeling, he argued, is currently where the most operationally beneficial progress is happening for the 48-hour wildfire-mitigation horizon.

Technosylva's positioning is also explicitly hybrid. Ratnathicam described the company's approach as "a unique combination of physical and empirical modeling, which strikes a critical balance between how the real world works, and reconciles what we are actually seeing."

Underneath the technical preference is a regulatory reality that all three providers gestured at. State public utility commissions, the Federal Energy Regulatory Commission (FERC), and class-action plaintiffs are increasingly asking utilities to document what they knew, when they knew it, and why they acted. That makes the forecast itself part of the utility's defensible record, alongside line patrols and inspection logs. As Goode put it, "weather intelligence is no longer only an operational input. It is part of the defensible record submitted after the event." Meteomatics described its platform in similar terms—a system in which utilities can "document exactly when thresholds were met, what alerts were triggered, and how those conditions justified the action."

Forecasting Gaps That Remain

Asked where advanced forecasting still falls short, the three providers gave different answers, but the answers triangulate. Climavision pointed to confidence rather than raw accuracy: utilities are awash in weather data, Goode said, but "short on knowing which conflicting model outputs to trust for their specific territory in the next 2–3 days." Sub-grid, terrain-driven wind behavior—ridges, lee slopes, coastal escarpments—remains under-resolved at public-grid scale, and fuel-state and vegetation dryness are not native variables in any standard weather model, forcing operators to stitch them in from separate feeds.

Hyde identified timing as the key gap—refreshing forecasts more frequently while preserving accuracy—and said Meteomatics is working on additional local wind fields, terrain effects, and thunderstorm-structure capabilities in the US1k model.

Ratnathicam said Technosylva's current research and development is focused on extending forecasts beyond the present five-day horizon without sacrificing accuracy. "Last August, we brought online the world's largest supercomputer dedicated to fire science—a substantial investment in high-performance computing that gave us full coverage of the U.S.," he said.

Forecasting as the Input to Grid Modernization

Whichever vendor a utility chooses—and many will run more than one—the strategic position of the advanced-forecasting layer in the broader grid-modernization stack is becoming clearer. Advanced forecasting, as Goode summarized, "sits at the input layer of grid modernization." Digital twins, dynamic line rating, vegetation-management programs, distributed-energy-resource dispatch, and predictive outage models all consume weather as a primary input. The accuracy and resolution of that input set the ceiling for every downstream decision.

The stakes underneath the engineering are not abstract. "Wildfires are becoming more frequent and more destructive," Ratnathicam said. "These events impact real people—their homes, their livelihoods, and their communities—they are not just data points on a screen."

For 2026, the practical question utilities are working through is not whether to invest in advanced forecasting but how to integrate it deeply enough that it shows up in operational decisions, regulatory filings, and capital plans. The May 2025 Houston event suggests what that looks like when it works. The 2024 derechos suggest what it looks like when it doesn't. ■

*—**Aaron Larson** is POWER's executive editor.*

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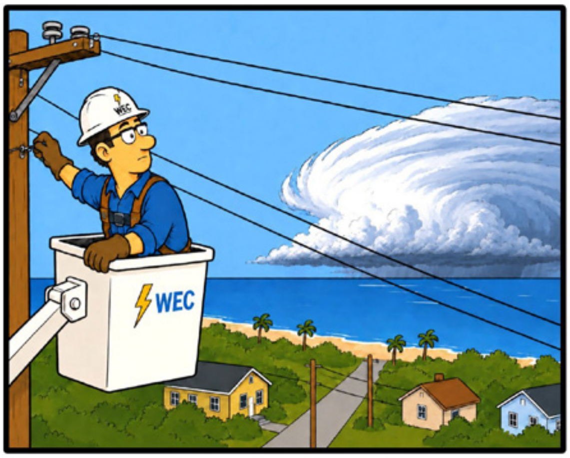

"LOOKS LIKE OVERTIME SEASON"

Wildfire Risk Is Rising. Electric Cooperatives Are Acting—Congress Must Too

Jim Matheson

Wildfires are no longer isolated disasters limited to the western United States—they are a growing threat to communities, infrastructure, and electric grid reliability nationwide. For the 42 million Americans served by electric cooperatives, the risk is especially acute. Co-ops power more than half the nation's landmass, primarily in rural areas where wildfire danger is highest and resources are often limited.

Electric cooperatives are on the front lines of wildfire risk reduction, response, and recovery. They operate tens of thousands of miles of power lines across forests, grasslands, and federally managed lands increasingly vulnerable to hotter, drier conditions and longer fire seasons. What was once a regional challenge has become a year-round operational reality for much of the United States.

Electric cooperatives are meeting this challenge. Policymakers must do the same.

Cooperatives Are Already on the Front Lines

Across the country, co-ops are investing in proactive wildfire mitigation strategies. They are expanding vegetation management programs, removing hazardous trees, and reducing fuel loads that can turn small ignitions into catastrophic fires. They are strengthening infrastructure with more resilient materials and upgrading systems to improve fault detection and speed response when risks emerge.

These efforts reflect the fundamental mission of electric cooperatives: delivering safe, reliable, and affordable power while putting communities first. Because co-ops are locally owned and governed, wildfire mitigation is not just a regulatory obligation—it is a direct responsibility to the people they serve.

Outdated Federal Rules Stand in the Way

But even as co-ops take decisive action, outdated federal policies are slowing progress at the worst possible time.

Cooperatives serve more federally managed public lands, national parks, and forests than any other type of electric utility. Routine maintenance and hazard removal on those lands are often subject to lengthy environmental reviews and bureaucratic delays. It can take months, or even years, to receive approval to replace a pole or remove a hazardous tree. Communities do not have that kind of time as wildfire risks continue to escalate.

In some cases, federal law limits the removal of hazardous trees to just 10 feet from power lines—an inadequate buffer that leaves critical infrastructure exposed. The result is a dangerous mismatch between the threat and the tools available to address it.

At the same time, electric cooperatives face unique financial constraints. As not-for-profit utilities, they operate on thin margins and have limited ability to absorb rising wildfire mitigation and recovery costs. Without policy changes, those costs ultimately fall on the communities co-ops are working to protect. This is why Congress must act now.

A Practical Fix Is Within Reach

The Fix Our Forests Act offers a practical solution to align federal policy with realities on the ground. Authored by House Natural Resources Committee Chairman Bruce Westerman, R-Ark., and passed by the House with overwhelming bipartisan support, the bill would modernize forest management, reduce wildfire risk, and give electric cooperatives the tools they need to better protect infrastructure and communities.

The bill would expand vegetation management authority, allowing co-ops to remove hazardous trees up to 150 feet from power lines instead of the current 10-foot limit. This change would reduce the risk of falling trees igniting fires and improve grid reliability.

In addition, the bill would streamline federal permitting by expanding categorical exclusions for low-impact projects. That means faster approvals for routine maintenance, system upgrades, hazard removal, and damage repairs—enabling co-ops to act quickly before conditions escalate.

The legislation would also eliminate outdated timber sale requirements that delay the removal of felled trees from utility corridors. By allowing faster cleanup, the bill would reduce fuel loads and lower wildfire risk in some of the most vulnerable areas.

Together, these reforms would improve wildfire mitigation while strengthening grid resilience and reliability at a time of growing demand and increasing risk.

The Time to Act Is Now

The urgency is clear. Wildfires are becoming more frequent and severe, threatening lives, homes, and critical infrastructure across the country. At the same time, electricity demand is soaring, placing additional strain on a grid that must remain reliable and resilient.

Electric cooperatives are doing their part. They are investing in prevention, innovating to reduce risk, and working every day to safeguard the communities they serve. But they cannot do it alone—especially when outdated federal policies stand in the way of urgently needed solutions.

Passing the Fix Our Forests Act would remove those barriers. It would empower electric cooperatives to act more quickly, effectively, and safely in the face of a growing wildfire threat. At a time when the risks are rising and the stakes are higher than ever, that is not just good policy—it is essential to the safety and well-being of rural communities. ■

*—**Jim Matheson** is CEO of the National Rural Electric Cooperative Association, representing nearly 900 not-for-profit, consumer-owned electric cooperatives. He previously served seven terms as a U.S. representative from Utah.*