More from the Grid We Have: Optimizing Demand Flexibility from the Grid Edge

Energy affordability is no longer a future concern. It is an urgent problem.

Electricity costs are rising across the United States. Utilities are investing in transmission and distribution expansion, system hardening, wildfire mitigation, and new capacity, all while financing costs remain elevated. Those investments are necessary, but they are also flowing directly into customer bills. But why is it happening? Public discourse has increasingly focused on the role of hyperscale data centers and large new loads. These developments are real and in some regions materially significant. But the reality is more nuanced.

Most grid constraints are not system-wide. They are localized, time-bound, and often driven by how existing load behaves across the distribution system.

The dominant narrative still centers on generation and large-scale demand growth. The more immediate pressure is coming from how the grid is being used. When we use energy is much more important than how much we're using at any given moment in time.

The system is increasingly built for moments, not averages.

Peak demand often occurs for fewer than 100 hours per year, yet it drives a disproportionate share of grid infrastructure investment.[1]

U.S. Department of Energy; National Renewable Energy Laboratory

More than half of U.S. utility capital spending is now directed toward transmission and distribution infrastructure.[2]

Edison Electric Institute; S&P Global Commodity Insights

By increasing annual system utilization by 10%, the new load is integrated at lower-than-average costs. Relative to current conditions, rates for all customers can be reduced by 3.4% [3]

The Brattle Group

A National Challenge Defined by Local Constraints

Energy affordability is shaped by local conditions, making each region of the country different. Climate, infrastructure age, regulatory structure, and load growth all influence where and why costs are rising. What is consistent across every region is the underlying dynamic: constraints emerge locally, often for short periods of time, but drive long-term infrastructure investment.

7 Mountain West

Colorado, Utah, Idaho, Montana, Wyoming, New Mexico

Large geographic service territories, long feeders, and rapidly growing metropolitan areas create dispersed and uneven load patterns. Climate variability adds additional stress to infrastructure. Visibility across the distribution system allows utilities to manage constraints that are geographically distributed but operationally interconnected.

8 California & Western States

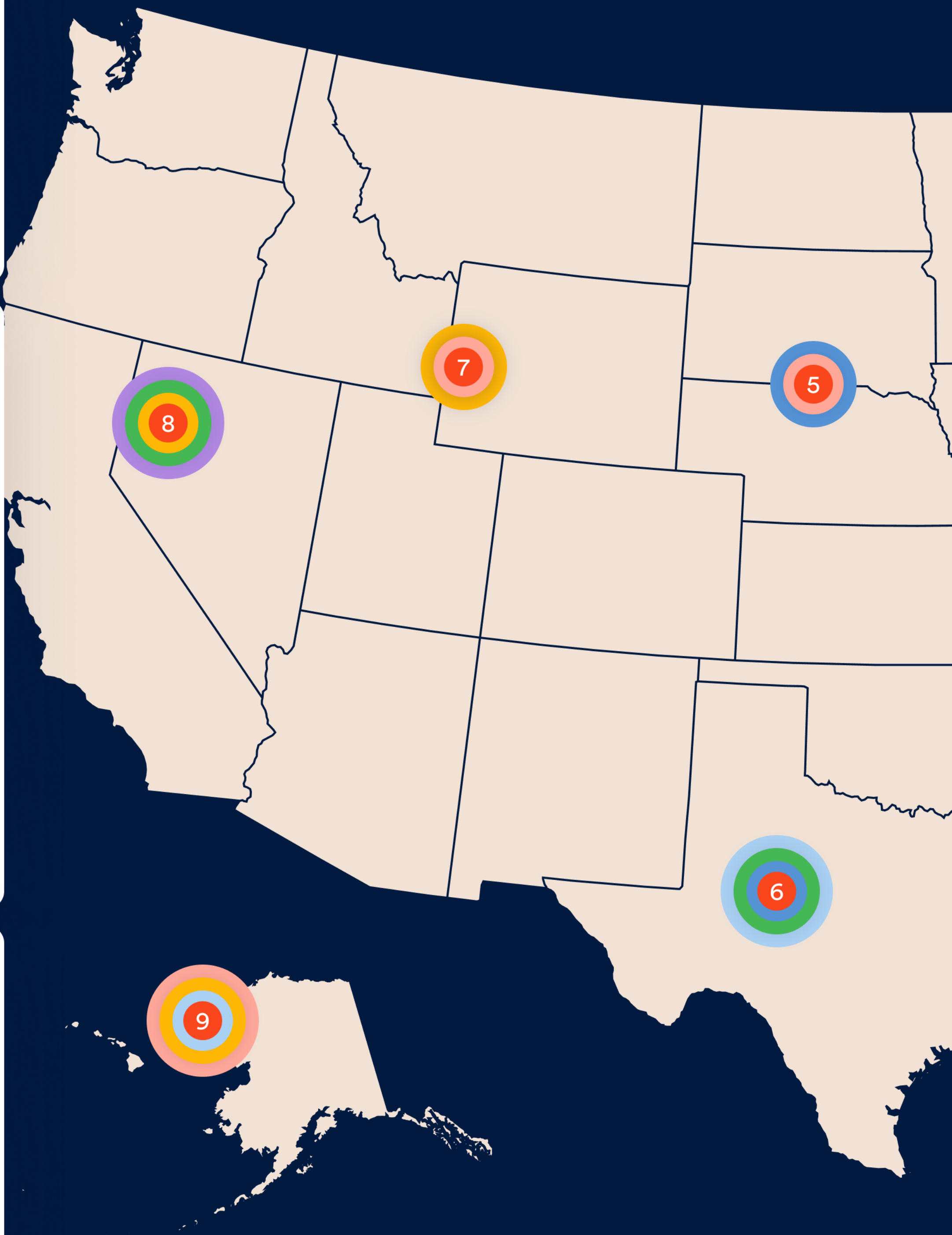
California, Oregon, Washington, Nevada, Arizona

Wildfire risk, climate variability, and aggressive electrification targets are reshaping grid investment priorities, making pushing past the limits of field equipment a real concern. The more limits are exceeded, the more equipment lifespan degrades. For example, wildfire-related costs now account for between 10% and 24% of total revenue requirements for California's major investor-owned electric utilities, according to the CPUC.[4] Distribution intelligence and automated control enable utilities to target hardening investments and reduce risk without system-wide overbuild.

9 Alaska & Hawaii

Alaska, Hawaii

Highly isolated grid systems with limited redundancy require precision in both planning and operations. Fuel costs, logistics, and climate conditions further increase system sensitivity. Localized visibility and coordinated flexibility are essential to maintaining reliability and controlling costs without overbuilding infrastructure.



1 Northeast

Maine, New Hampshire, New York, Vermont, Massachusetts, Rhode Island, Connecticut

Seasonal peaks, particularly in winter, and exposure to wholesale market volatility drive affordability challenges. Constraints are often tied to heating electrification and limited local generation during peak periods.

Distribution-level visibility enables targeted peak reduction and more precise load shaping, reducing reliance on expensive wholesale procurement.

2 Mid-Atlantic / PJM

New Jersey, Pennsylvania, Delaware, Maryland, Virginia, West Virginia, Ohio, District of Columbia

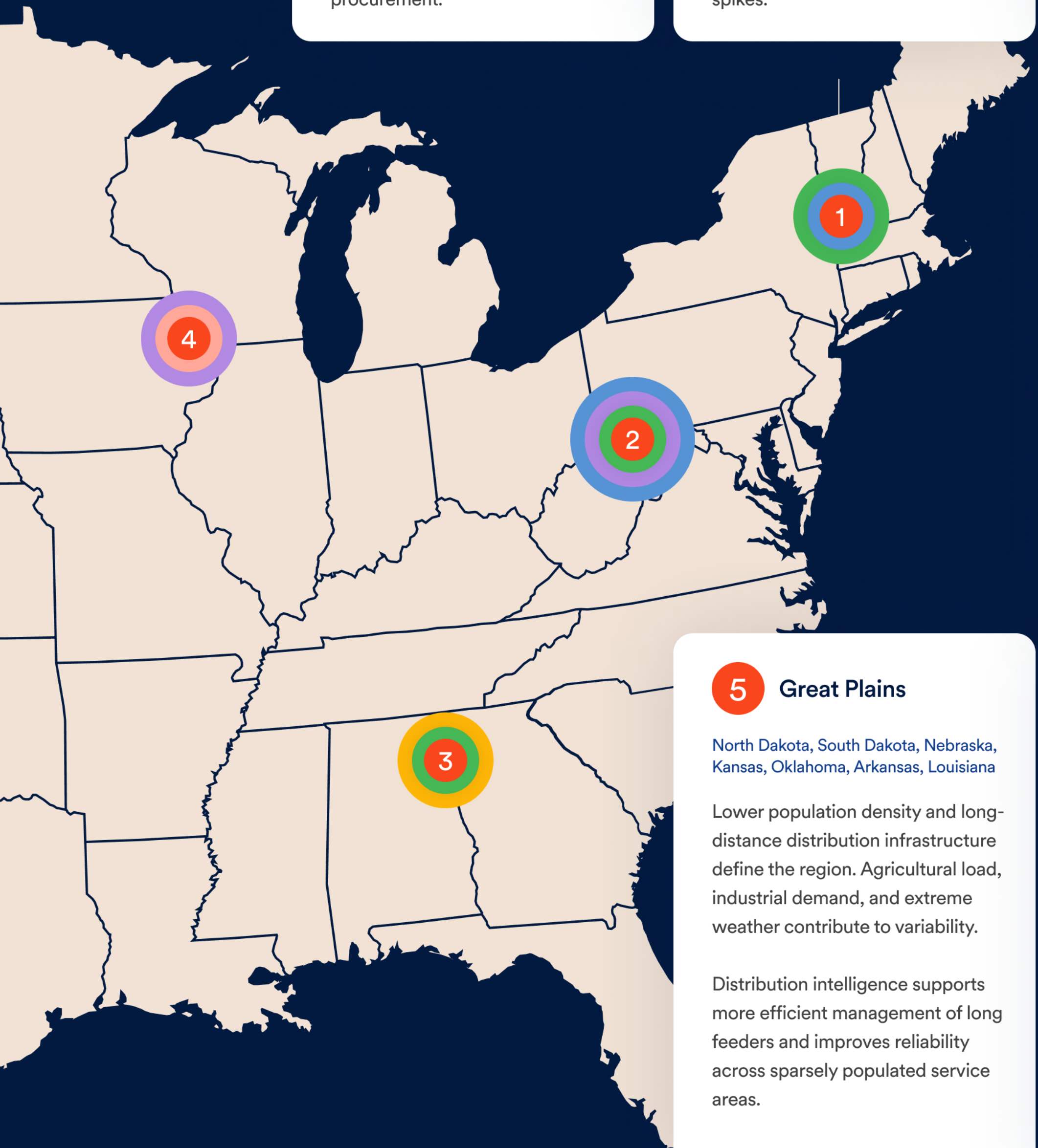
Load growth from electrification and large commercial demand is colliding with transmission expansion needs and interconnection backlogs. While hyperscale data centers are part of the narrative, many constraints emerge at the feeder and substation level. Distribution intelligence allows utilities to sequence upgrades more precisely and avoid overbuilding for localized demand spikes.

3 Southeast

North Carolina, South Carolina, Georgia, Florida, Alabama, Mississippi, Tennessee, Kentucky

Rapid population growth and economic development are driving sustained load increases. Vertically integrated utility structures place pressure on long-term capital planning and rate stability.

Distribution-level insight enables proactive infrastructure planning and targeted flexibility, helping utilities manage growth without uniformly expanding capacity.



4 Midwest

llinois, Indiana, Michigan, Wisconsin, Minnesota, Iowa, Missouri

Aging infrastructure and ongoing capital replacement cycles are major drivers of rising rates. Load growth is moderate but uneven, with localized constraints emerging across older distribution networks.

Enhancing visibility through AMI 2.0 investments allows utilities to prioritize upgrades and extend the useful life of existing assets.

5 Great Plains

North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, Arkansas, Louisiana

Lower population density and long-distance distribution infrastructure define the region. Agricultural load, industrial demand, and extreme weather contribute to variability.

Distribution intelligence supports more efficient management of long feeders and improves reliability across sparsely populated service areas.

6 Texas

An isolated grid with high exposure to extreme weather events and rapid load growth creates unique reliability challenges. Peak demand events are increasingly acute, and wholesale price volatility remains a concern.

Distribution-level intelligence supports localized resilience, faster response to emerging constraints, and more effective peak management.

What this map shows

Regional cost drivers and where targeted distribution intelligence can reduce infrastructure spending and improve affordability.

- Peak volatility
- Growth pressure
- Wildfire / climate risk
- Aging infrastructure
- Geographic dispersion
- Isolation

Grid constraints are not theoretical. They are already shaping how utilities invest and how customers pay. Peak demand, short-duration load spikes, and infrastructure built for worst-case scenarios drive capital decisions. Utilities must build systems that can handle infrequent peaks, and customers pay for that capacity every day.

This structural inefficiency is at the center of today’s affordability challenge.

Traditional energy efficiency programs were designed to reduce total consumption. That remains important, but it no longer aligns with the primary cost drivers of the system. Reducing kilowatt-hours alone does not address peak stress. At the same time, broad flexibility programs without precise visibility often overcorrect, adding cost without resolving the underlying constraint.

Efficiency without flexibility is incomplete. Flexibility without visibility is imprecise.

In addition to building more infrastructure, utilities can also unlock capacity that is already embedded within the distribution system. That requires a coordinated approach that brings together real-time visibility, targeted flexibility, and actionable efficiency. This is not a marginal improvement. It is a shift in how the grid manages its load. And it starts at the grid edge.

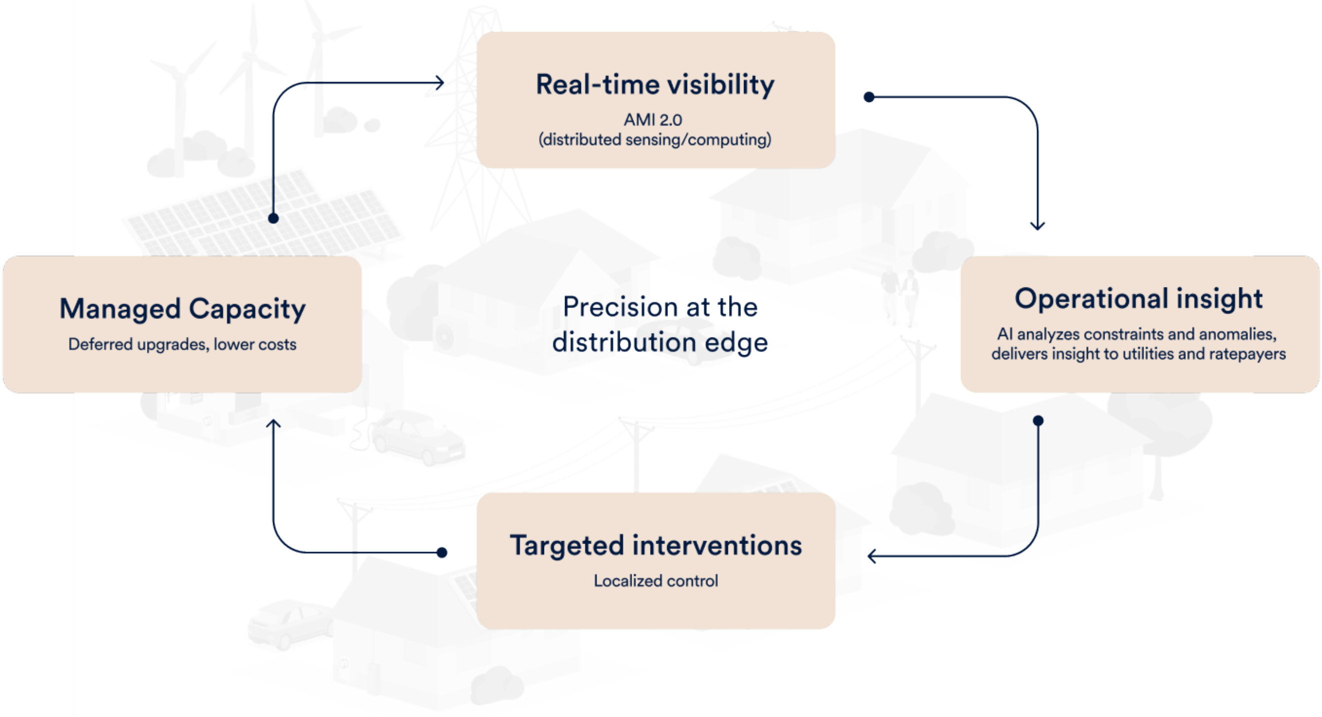
From constraint to precision

Unlocking the capacity already embedded in the grid requires a different operational model at the distribution edge. One that reflects a simple reality: most constraints are local, dynamic, and short in duration, but they drive long-term cost.

Today's demand response and energy efficiency programs were not designed for this environment. They were built around broad system-level assumptions and generalized incentives intended to reduce aggregate consumption. But the emerging challenge is not simply how much electricity is used. It is when and where load appears on the system, and whether utilities can respond with enough precision to avoid unnecessary infrastructure expansion.

Managing load growth and affordability in the next decade will require utilities to modernize demand-side management itself. Programs must evolve from static, system-level and probabilistic to continuous, localized, and increasingly automated. As shown in Figure 1, this creates a closed-loop operational system: visibility reveals system conditions, intelligence identifies constraints, and targeted action resolves them. The result is a grid that can absorb more load while making better use of existing infrastructure.

Figure 1: The Grid Edge Intelligence Loop



Turning visibility into action

Building this model requires utilities to rethink how data, intelligence, and control operate across the distribution system. Historically, utilities have operated with limited visibility into real-time conditions at the edge of the grid. Compared to sectors such as logistics, telecommunications, or digital advertising, the electric industry has had relatively little operational data available at high frequency and large scale. That is beginning to change.

Three developments are converging at the same time.

1. **Modern grid infrastructure is generating significantly more high-resolution operational data, particularly through next-generation smart meters.**
2. **Artificial intelligence is making it possible to translate that data into operational intelligence quickly enough to support real-time decision making and automated control.**
3. **Utilities are increasingly capable of leveraging distributed computing architectures that process information closer to the edge of the grid, rather than relying exclusively on centralized systems. The model is similar to how mobile navigation platforms continuously process information from millions of distributed devices to optimize traffic conditions in real time.**

Together, these developments create the foundation for a fundamentally different approach to demand response and efficiency. The shift is from historical aggregated visibility to continuous, high-resolution awareness of how the system is operating in real time. And the smart meter is where that transition begins.

Establishing real-time visibility

Next-generation smart meters (AMI 2.0)

Modern meters are no longer limited to billing and interval data. They can act as distributed sensing, computation, and control systems for the distribution grid, making use of high-frequency electrical signals at the edge of the system. By processing data at the meter, more detailed insights can make their way back to utilities for optimization.

This creates a network of measurement points across feeders, transformers, and service lines. Utilities gain a direct view of how load behaves, where it is changing, and where stress is emerging. Coupled with dynamic pricing and automated controls, next-generation meters also create a direct pathway for load shaping. Utilities and customers can respond to conditions in real time, reducing peak stress while lowering customer costs.

Without this level of visibility and intelligence, planning defaults to conservative assumptions. Infrastructure is built for worst-case conditions, regardless of how often those conditions occur. Grid innovation starts at the meter.

Artificial intelligence

High-resolution data must be translated into usable intelligence that can be automated into load control at scale. Artificial intelligence processes high-resolution waveform and usage data to detect anomalies, identify emerging faults, and characterize load behavior as it develops. It allows utilities to move beyond knowing that the system is under stress to understanding where and why constraints are forming, quickly.

This changes the operating model. Decisions can be made based on actual system conditions rather than forecasts and modeled scenarios alone. Response shifts from reactive deployment to anticipatory and automated controls.

Customer-integrated intelligence

The final layer of modernization extends visibility into the home.

By translating electrical signals into device-level insight, consumers gain clarity on what is actually driving their energy bills. Energy use becomes a set of identifiable and controllable behaviors that enable more active partnership between utilities and their customers.

This changes the effectiveness of demand response and efficiency programs. Instead of broad behavioral campaigns or generalized rebates, utilities can design interventions around real load drivers and actual customer conditions. For example, if a customer agrees to enroll a smart heat pump in a program and allow some level of utility control of the device, a utility could then provide additional rate incentives.

This gives consumers a more active role in affordability. The result is a more coordinated relationship between utilities and customers, where flexibility becomes continuous rather than event-driven.

Acting with precision

With visibility and insight in place, utilities can act directly on the source of constraints. Traditional demand-side programs operate broadly. They influence large populations and rely on probabilistic outcomes. Targeted interventions operate differently. Utilities can identify the specific devices and conditions contributing to a localized constraint and address them directly, shifting load where and when it matters. This reduces unnecessary disruption and increases effectiveness. Grid management moves from managing averages to managing actual conditions on the system.

Managing capacity

The immediate outcome of this approach is the ability to keep demand within the capacity of existing infrastructure. When constraints are identified early and addressed locally, utilities can avoid hitting equipment load limits. That avoidance also enables utilities to avoid or defer upgrades to transformers, feeders, and service lines. These upgrades are among the fastest-growing drivers of distribution-level cost. This allows capital to be deployed more precisely and enables new load to be added without triggering cascading infrastructure expansion.

Sources

[1] National Renewable Energy Laboratory, *Maintaining a Reliable Future Grid with More Wind and Solar* (Golden, CO: U.S. Department of Energy, National Renewable Energy Laboratory, 2024).

[2] Edison Electric Institute, *Industry Capital Expenditures: 2025 and Beyond* (Washington, DC: Edison Electric Institute, 2025).

[3] The Brattle Group, *The Impact of Data Centers on Electricity Costs and Reliability* (Boston, MA: The Brattle Group, 2024).

[4] California Public Utilities Commission, Office of the Public Advocates, Electric IOU Wildfire Cost Increases (San Francisco, CA: California Public Utilities Commission, June 2024).

About Sense

Sense is a grid-edge intelligence company serving electric utilities that want to extract greater operational value from advanced metering infrastructure.

Contact us

Want to find out more?
Learn more about Sense: sense.com
Get in touch with the team: utilities@sense.com
For media inquiries: press@sense.com

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