2025 State of the grid edge

How Virtual Power Plants are transforming the energy landscape

INTRODUCTION

The grid edge takes center stage

The U.S. electricity system faces unprecedented challenges. Electrification efforts, manufacturing reshoring, and data center growth are driving dramatic increases in electricity demand, creating urgent new capacity requirements that traditional generation resources cannot meet.

The scale of this challenge is staggering. U.S. electricity demand is projected to increase 15.8% by 2029. Peak demand is expected to grow from 800 GW in 2024 to approximately 900 GW in 2030, with an additional 100 GW needed to replace retiring fossil-fuel units. At the same time, new gas turbine costs are rising dramatically, with production capacity tied up until 2030.

Grid-edge technologies — particularly virtual power plants (VPPs) that aggregate distributed energy resources (DERs) like electric vehicles (EVs), smart thermostats, and residential battery storage systems to balance the grid — offer a critical tool for alleviating this capacity crunch. By tapping into customer-sited resources, utilities can build large-scale distributed capacity that is more cost-effective, faster to deploy, and more flexible than traditional infrastructure-based approaches.

This white paper examines the current state of VPPs and grid-edge technologies, highlighting their growing role in maintaining grid reliability and enabling a cleaner, more resilient energy future.

Readers will gain an understanding of why:

1. Integrated multi-DER portfolios are expanding VPPs' potential
2. Data-driven recruitment and retention strategies are now essential capacity levers
3. Advanced dispatch strategies are unlocking new value streams
4. VPPs are evolving from seasonal to year-round flexibility resources

VPPs are meeting the moment in 2025

Virtual power plants are often seen as a lesser alternative to conventional generation, unable to provide the scale or precision utilities need — but in an increasing number of cases, they actually outperform traditional resources. According to a Brattle Group study, the net cost to a utility of providing resource adequacy from a VPP is roughly 40–60% of the cost of conventional options like natural gas peaker plants or utility-scale batteries.

The same study found that deploying 60 GW of VPPs could meet future U.S. resource adequacy needs at a cost that is $15–$35 billion lower than infrastructure-based solutions over the next decade. Additionally, these deployments would deliver $20 billion in societal benefits, including reduced emissions and enhanced grid resilience. Beyond cost savings, VPPs can also help meet resource adequacy needs faster than traditional alternatives; whereas traditional generation can take years to build and even longer to interconnect, VPPs can be launched and scaled in a matter of months.

Real-world examples demonstrate that VPPs are not merely theoretical concepts but viable, reliable solutions. During the summer of 2024, EnergyHub's 80+ utility clients activated their VPPs over 2,000 times, a 26% increase compared to 2023. These deployments shifted more than 44 GWh of electricity out of peak periods, equivalent to the annual production of about five fossil fuel peaker plants. They also reduced over 16,500 tons of CO_2 emissions.

In 2024, EnergyHub's 80+ utility clients delivered

+26%
Increase in VPP dispatches YoY

44 GWh
Electricity shifted out of peak periods

16.5k tons
of CO_2 emissions saved

VPPs are also gaining regulatory momentum. In 2024, [105 state and investor-owned utility (IOU) regulatory actions](#) supporting VPPs and distributed energy resources (DERs) were implemented across 37 states and Washington, D.C. These regulatory developments will accelerate deployment of flexible technologies, especially as [nearly three-quarters](#) (72%) of utility leaders report that regulatory compliance and mandates are the primary driver of innovation within their organizations.

STATES WITH REGULATORY ACTIONS SUPPORTING VPPS IN 2024

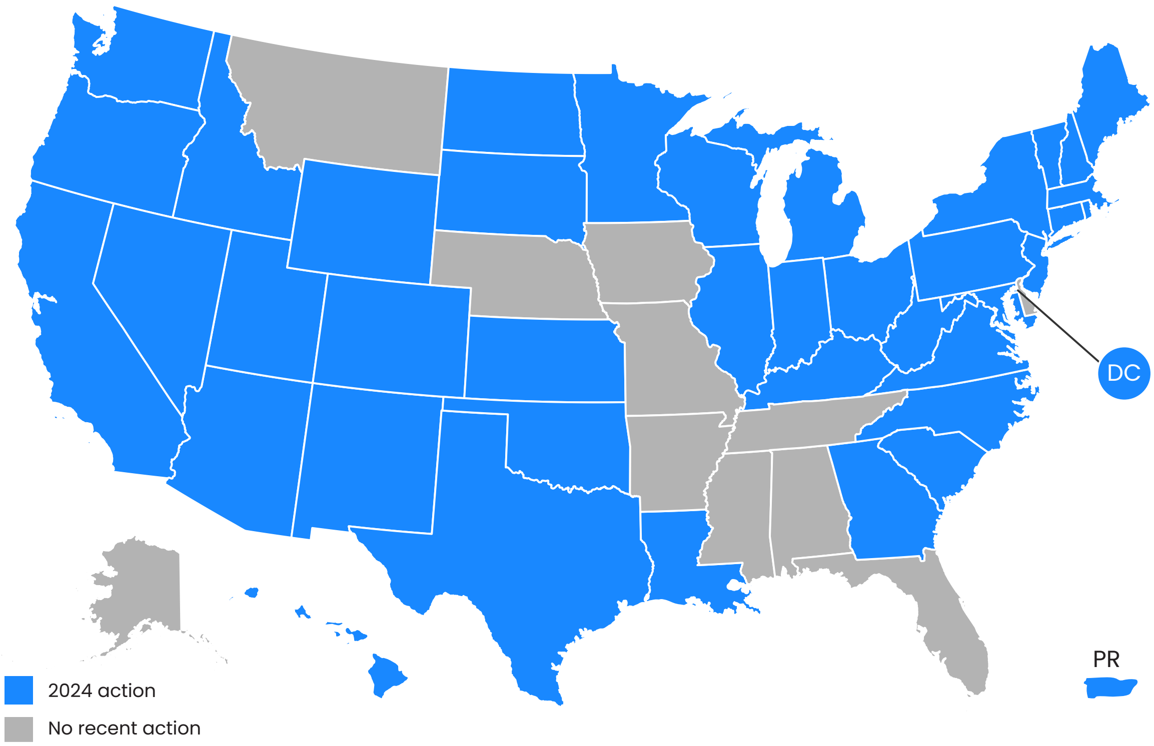


Fig. 1: Map showing the 38 states and territories that took regulatory action to support VPPs in 2024. (Source: SEPA)

DER DEEP DIVE

What's changing behind the meter?

The U.S. is predicted to add [217 GW of DER capacity] through 2028, with curtailment-based resources, EV charging, and building automation systems accounting for half that total. Each type of DER brings unique characteristics to the VPP ecosystem — from the rapid scalability of thermostats to the dispatchable capacity of batteries and the flexible load management of EVs. Understanding these behind-the-meter technologies and how customers interact with them is essential for utilities seeking to design effective VPP programs that can address multiple grid needs.

Thermostats: The VPP foundation

Thermostat programs continue to be the backbone of residential VPPs in 2025, accounting for a disproportionate share of VPP capacity in North America. Thermostats offer several advantages that make them ideal foundational resources for VPPs:

- Large installed base of compatible devices
- Relatively consistent load impact per device
- Low cost per kW of capacity

Over the past five years, EnergyHub's bring-your-own-thermostat (BYOT) programs have grown on average 63% between their first and second years in operation. This rapid scalability plays a crucial role in addressing immediate grid constraints. Equally important, however, is ensuring that program growth is predictable and sustainable enough to support long-term planning. In 2024, EnergyHub thermostat programs showed less than 7% variance between forecasted and actual enrollment, underscoring both the scale and reliability of BYOT programs.

As these programs continue to expand, utilities are also refining how they control thermostats to improve customer experience. Strategies like **pre-cooling** and **smart events** — which stagger dispatch to reduce the duration of any single device's participation while sustaining overall load shed — have proven to reduce opt-outs by 20% compared to standard demand response events.

Meanwhile, thermostats are enabling a new generation of "background VPPs" through **microshifting**: small, always-available adjustments that support the grid in near real-time without noticeable impact to customers. With broad adoption and growing technical capabilities, thermostats are uniquely positioned to unlock emerging use cases like locational dispatch and more precise load shaping going forward, cementing their role as an essential pillar of any VPP.

Thermostat scale spotlight

Ontario's IESO reaches 250,000+ devices within 24 months

The IESO introduced its thermostat-based Save on Energy Peak Perks™ program in June of 2023. The program scaled rapidly, with Peak Perks becoming the largest residential VPP in Canada in its first six months. Peak Perks has continued to scale at a record-setting pace, surpassing 250,000 enrolled devices at the end of June, 2025 and delivering an estimated one-hour peak demand reduction of over 180 MW of on its highest-performing day.

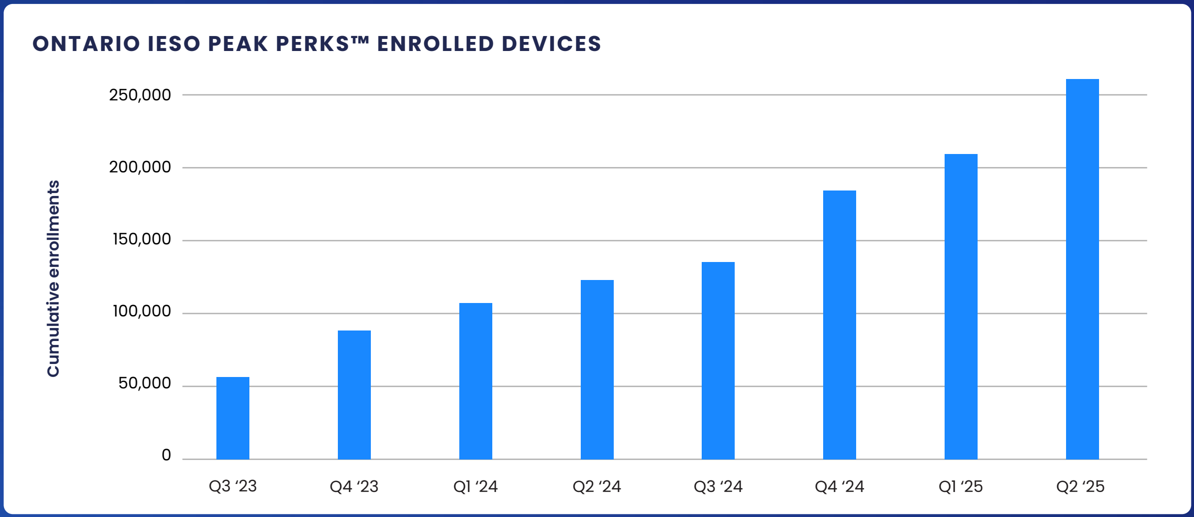


Fig. 2: Quarterly enrollment in IESO's Peak Perks™ thermostat VPP program since launch. (Source: EnergyHub)

Residential batteries: Adding critical capacity

The battery storage market continues its strong growth trajectory in 2025, adding critical capacity and flexibility to VPPs. The residential attachment rate — the percentage of solar installations that include battery storage — doubled from 14% in 2023 to 28% in 2024 and is projected to reach 35% in 2025. Utilities and policymakers are taking notice, with many utilities expanding their VPP offerings to include battery storage programs or pilots in 2024, including APS, Dominion Energy Virginia, Duke Energy (North Carolina), PSEG NJ, and Puget Sound Energy.

Residential batteries have become a fast-growing component of VPPs by providing:

- Large flexible capacity relative to other DERs
- Precise, rapid dispatch
- Longer duration events (2-4 hours)
- More frequent events, including daily
- Year-round control

RESIDENTIAL BATTERIES IN ACTION: 31 MWH LOAD SHIFT

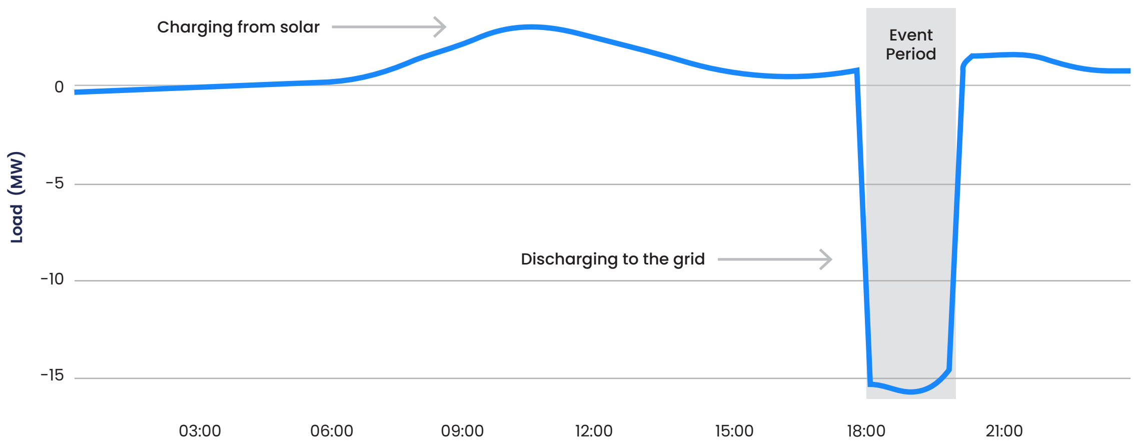


Fig. 3: East Coast utility shifts 31 MWh away from the peak in June, 2025 using residential batteries. (Source: EnergyHub)

Customer motivations driving increased battery adoption vary nationwide. When California rolled out NEM 3.0, which rewards consumption of solar generation, attachment rates rose to [60-68%,](#) up from 15-20% in the year prior. In regions where resilience is top of mind, such as Puerto Rico and Hawaii, attachment rates have [reached nearly 100%](#), reflecting widespread consumer demand for backup power in the face of frequent outages and severe weather events.

For utilities, ensuring these new battery owners enroll in flexibility programs will be key. This requires understanding the regional nuances driving battery adoption, forging close partnerships with OEMs and installers, and providing a frictionless and rewarding customer experience. One East Coast IOU on the EnergyHub platform has seen early success in this regard, enrolling about nine out of every 10 newly installed batteries in its pilot program since launching.

BATTERY PROGRAM GROWTH: EAST COAST IOU PILOT FLEXIBLE CAPACITY

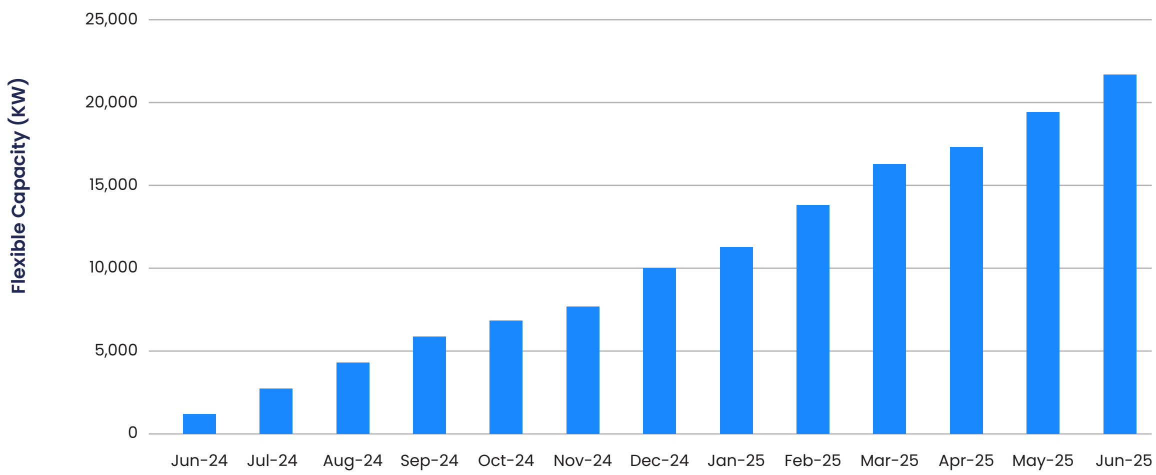


Fig. 3: East Coast utility shifts 31 MWh away from the peak in June, 2025 using residential batteries. (Source: EnergyHub)

EVs: Steady growth, rising uncertainty

Electric vehicles are both a challenge and an opportunity for grid operators, representing a new class of flexible DERs as well as an unpredictable source of load growth. EV sales are still growing, with nearly 300,000 new electric vehicles sold in the first quarter of 2025 in the U.S. — an increase of 11.4% year over year. Still, **Cox Automotive** anticipates that the rest of 2025 will likely be "volatile" for EV sales in the U.S.

Even with this near-term uncertainty, utilities must prepare for the unique load challenges EVs can cause. Research by **AES and Camus Energy** identified a 5% EV adoption "tipping point" where the benefits of investing in EV managed charging solutions exceed the costs for utilities. These effects can be unintentionally amplified by time-of-use rate plans, which often cause many drivers to plug in and begin charging at the same time when the on-peak period ends. In response, utilities are increasingly turning to active managed charging to address EV charging peaks.

Our research has found that active managed charging can reduce EVs' peak demand on distribution assets by as much as 30% compared to unmanaged charging. While time of use (TOU) rates might seem like an efficient means of managing EV load, they can increase the risk of thermal overload to distribution network elements by creating an unintended "timer peak" at the conclusion of TOU periods.

ACTIVE MANAGED EV CHARGING REDUCES PEAK DEMAND

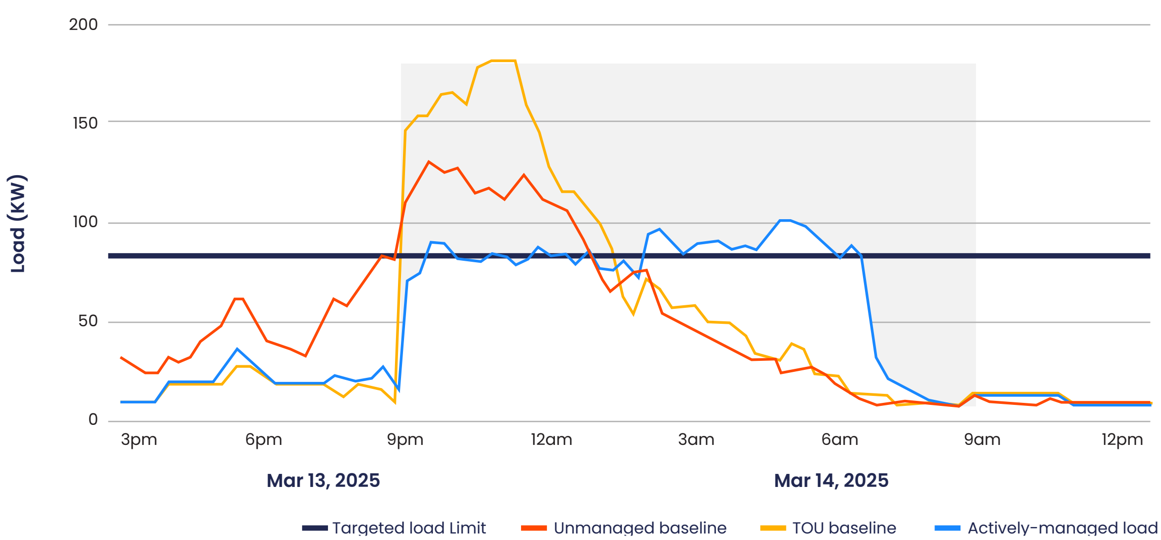
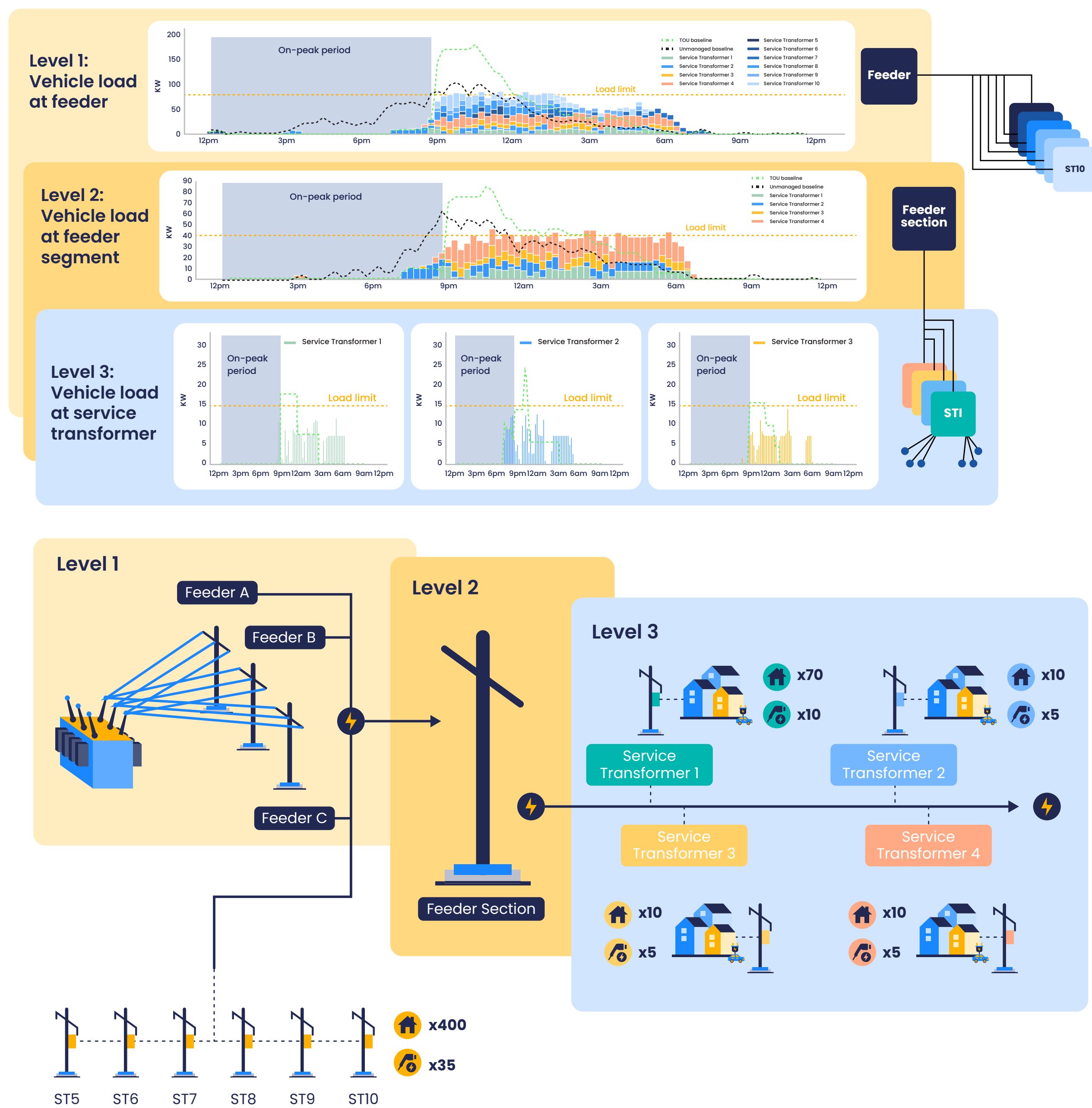


Fig. 5: Results from a managed charging program in which EVs are managed to shift load away from the TOU peak period, while keeping loads at/near a targeted load limit. Max EV load was reduced by half relative to an estimate of what the EVs would have consumed under simple TOU rate optimization (Yellow line).

Looking ahead, EV managed charging strategies are evolving to deliver even greater benefits at the distribution level, with features like **multi-level load limiting** allowing utilities to set aggregate charging limits at the service transformer, capacitor bank, and feeder levels as demonstrated in Figure 6. Distribution load optimization (DLO) coordinates and enforces EV charging limits simultaneously at multiple levels of the distribution grid. DLO protects substations, feeders, service transformers, and other distribution assets concurrently through intelligent controls that spread energy consumption to minimize load spikes on distribution assets.



MULTI-LEVEL LOAD LIMITING REDUCES EV CHARGING LOAD ACROSS MULTIPLE LEVELS OF THE DISTRIBUTION NETWORK

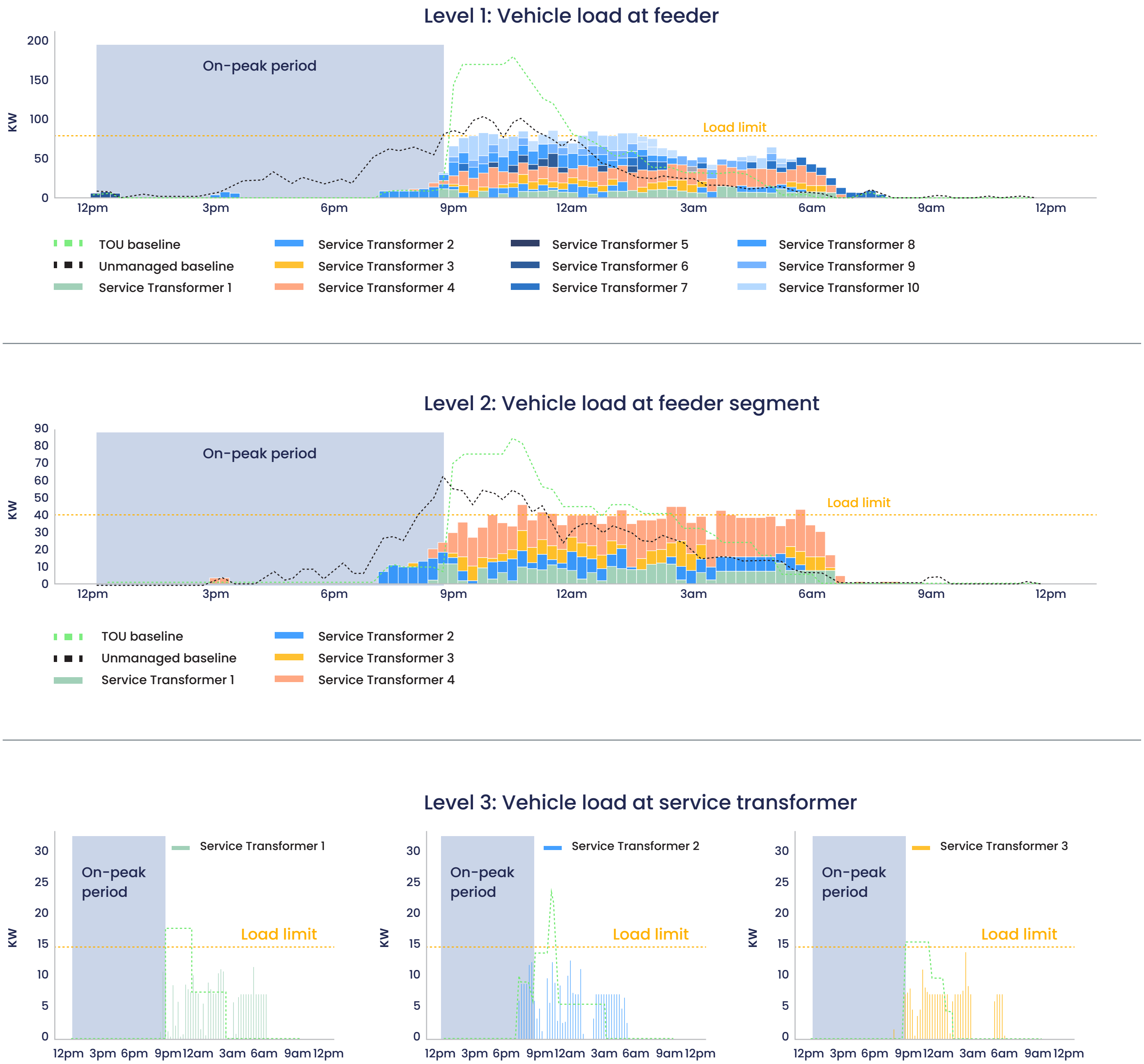


Fig. 6: EnergyHub's managed charging platform uses multi-level load limiting to keep aggregate EV charging load under specified limits using three levels of load limiting: (1) a feeder, (2) a feeder segment, and (3) eight service transformers. (Source: EnergyHub).

Cross-DER integration: The whole is greater than the sum

VPPs combining multiple DER types are gaining significant traction as utilities and regulators recognize the complementary capabilities of different resources and the technological and operational efficiencies of managing one VPP. In particular, state policy actions are increasingly supportive of using multiple types of DERs together, reflecting growing recognition of the value of integrated approaches.

Cross-DER VPPs enable dispatch capabilities that single-technology programs cannot achieve. Cross-DER VPPs can:

- Deliver specified load shapes
- Support longer events
- Minimize post-event snapback
- Optimize dispatch for both customer experience and grid needs
- Solve for both bulk- and distribution-level constraints

To fully realize the benefits of cross-DER VPPs, utilities need a platform capable of managing diverse devices in a unified, intelligent way. An Edge DERMS provides exactly that — a single system that enables visibility, orchestration, and optimization across multiple DER types. It also unlocks advanced flexibility strategies like **smart events**, which leverage machine learning and optimization to dispatch precise groups of devices in phases and achieve a targeted load shape that balances grid needs with customer comfort.

Cross-DER spotlight

nationalgrid **National Grid orchestrates batteries and thermostats to achieve flat load shape and eliminate snapback**

In 2024, National Grid piloted a smart event on the EnergyHub platform using a combination of 20,000 thermostats and 2,400 residential batteries. During this four-hour event, they achieved a seamless handoff between thermostats and batteries, delivering a consistent load shape and minimal snapback to ensure load shed during coincident peak hours.

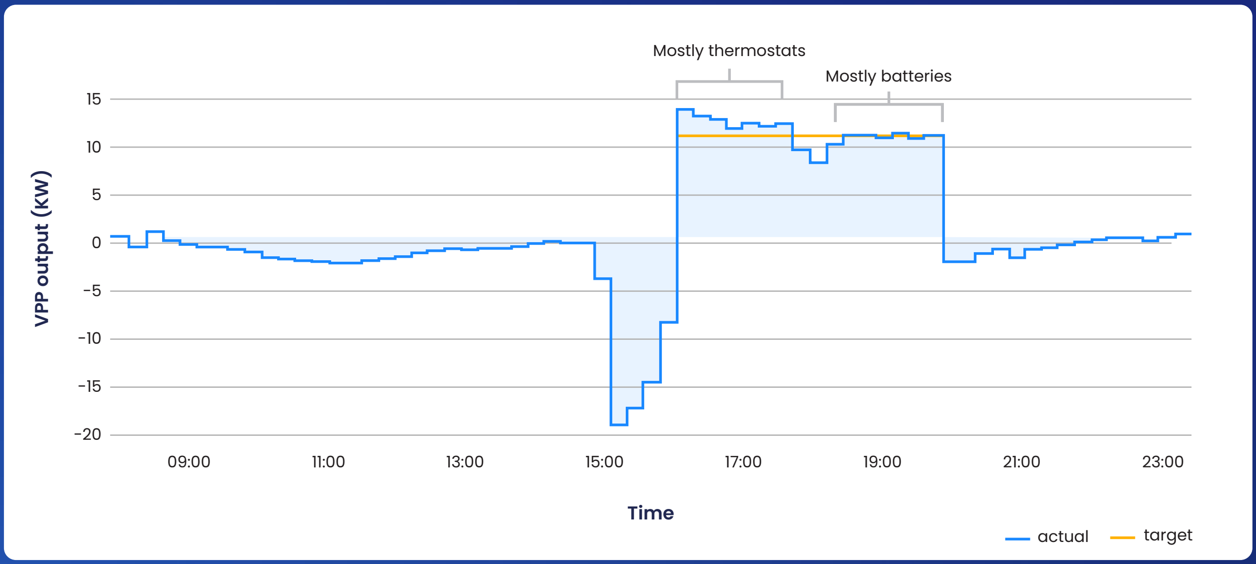


Figure 7

What's next? Trends shaping the future of VPPs

Scaling for success: Customer experience is key

As VPPs scale from pilots to critical grid resources, customer experience continues to be a central pillar of program success. To keep customers enrolled long-term, utilities must deeply understand customer motivations, behaviors, and barriers and design program experiences around them. This means aligning everything from marketing and enrollment to program design and event strategy with customer needs.

Our data shows that 96% of thermostat program participants will stay enrolled over the course of a summer season. But maintaining high retention over the course of multiple years is more challenging. Churn usually arises from three main sources:

- **Move-ins and move-outs**: Customers relocating outside of the utility's service area, customers failing to re-enroll after moving within the utility's service area, or new residents failing to enroll a previously participating device at their address
- **Disconnected devices**: Wi-Fi issues, device replacements, and other changes that disrupt device connectivity
- **Customer experience**: Customers leaving the program due to dissatisfaction with the frequency or length of events, incentives, customer support, etc.

While some attrition is inevitable, even modest improvements to retention can yield significant capacity gains, as shown in Figure 8 and Table 1.

RETENTION GAIN OVER TIME - 200K COHORT

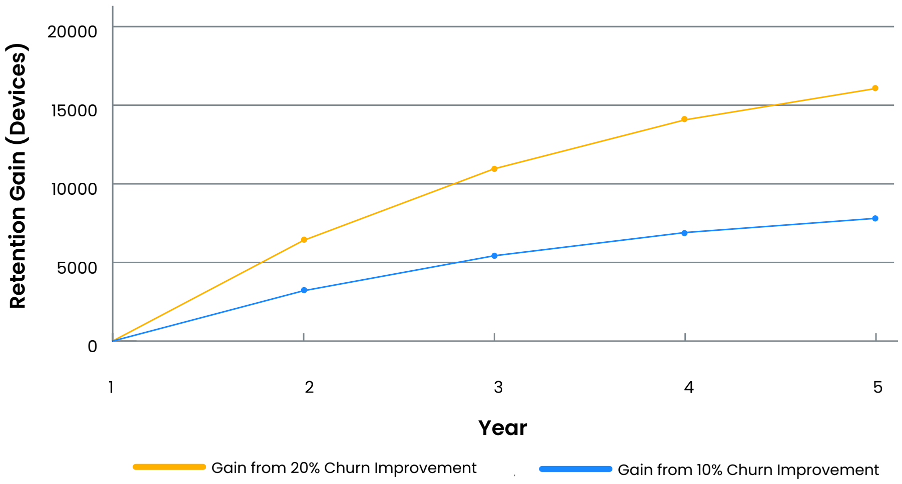


Figure 8

Starting program size (devices)	Program size after 5 years (baseline)	Program size after 5 years with 10% annual win-back rate	Program size after 5 years with 20% annual win-back rate	Potential capacity savings
10,000	**22,153**	**23,339**	**24,571**	**1.19 - 2.42 MW**
50,000	**110,767**	**116,693**	**122,853**	**5.93 - 12.09 MW**
100,000	**221,533**	**233,386**	**245,707**	**11.85 - 24.17 MW**
200,000	**443,067**	**466,771**	**491,414**	**23.7 - 48.35 MW**

Table 1: Impact of customer retention rate on thermostat VPP program capacity assuming a baseline annual churn rate of 16% and a baseline annual net growth rate of 22%.

Utilities that have invested in lifecycle optimization strategies are already seeing results. Campaigns to reconnect offline devices, improvements to enrollment flows, and multi-channel engagement tactics have driven measurable improvements in retention and conversion for EnergyHub's clients.

Additionally, customer-focused dispatch strategies like **smart events** — which use machine learning to dispatch devices in short, coordinated phases — can shorten the duration each customer's device is actively controlled while maintaining load reduction targets.

Smarter, optimized dispatch

VPPs aren't just getting bigger — they're also getting smarter. Advancements in forecasting, telemetry, and device grouping have enabled sophisticated dispatch strategies like [smart events](). Arizona Public Service implemented this approach on September 27, 2024, using smart thermostats in its Cool Rewards Program to balance multiple objectives in the same event, including:

- Optimizing around solar production
- Aligning dispatch with customer TOU rates
- Minimizing snapback

The EnergyHub platform automatically grouped and dispatched devices in small batches throughout this event using a three-phase approach:

1. Pre-cooling homes during peak solar production
2. Maintaining steady load before TOU rates began
3. Progressively activating additional thermostat groups during TOU hours

This strategy delivered the desired load shape, achieving an optimization window exceeding seven hours with graduated load reduction throughout, minimal snapback, and the highest reported customer satisfaction and comfort scores of any event that season. This represents the next generation of VPP capabilities where precise control can deliver customer comfort and grid optimization simultaneously.

SMART EVENT: APS ACHIEVES MULTI-OBJECTIVE OPTIMIZATION

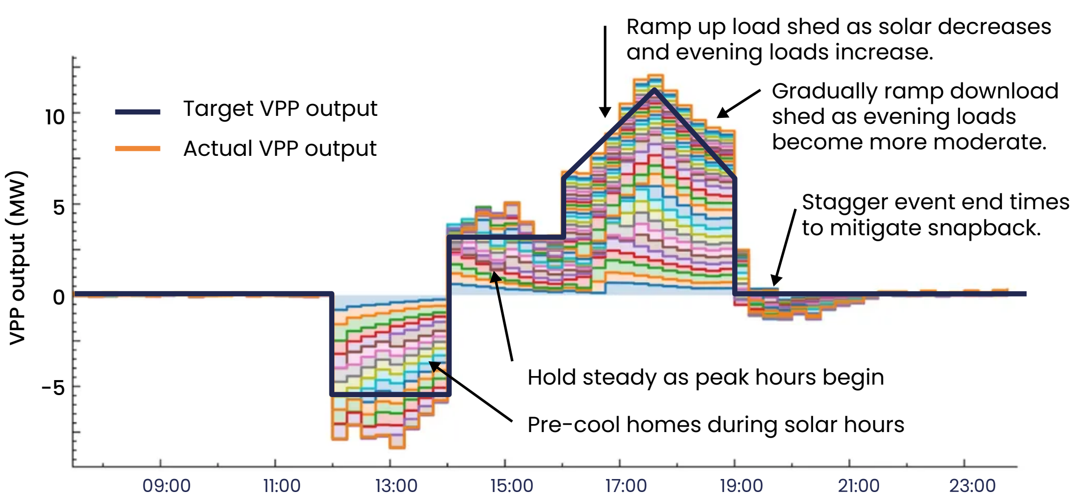


Fig. 9: VPP output by DER group during a smart event. The load shape was designed to absorb solar power during mid-day hours, avoid extra consumption during the TOU peak hours, and shape load based on grid needs (APS). (Source: EnergyHub)

Customer choice drives the next wave of growth

As DER adoption shifts from early adopters to the mass market, customer choice is becoming even more important. Today's program participants are more diverse in their brand preferences, needs, expectations, and comfort with technology. For VPPs to scale effectively, they must accommodate this diversity — offering flexibility in device selection, enrollment pathways, and incentives.

An Edge DERMS can provide utilities with a turnkey network of eligible device partners for their flexibility programs, maximizing customer choice from day one. This breadth of compatibility ensures customers can participate using the devices they already own and trust — while utilities can design inclusive programs that meet grid needs at scale.

DER type	Market share covered by EnergyHub's OEM partnership
Thermostats	95%
EV and EVSE	90%
Batteries	90%

Customer choice also extends to compensation. According to Choice Digital's [2025 State of Energy Payments] report, 88% of customers would be very satisfied with their utility if they had a choice in how incentives are paid out. As incentive preferences shift — especially among younger and lower-income participants — programs that offer options like instant payments, digital gift cards, or prepaid debit cards can significantly boost enrollment and satisfaction.

PREFERRED INCENTIVE PAYOUT METHODS FOR FLEXIBILITY PROGRAM PARTICIPANTS

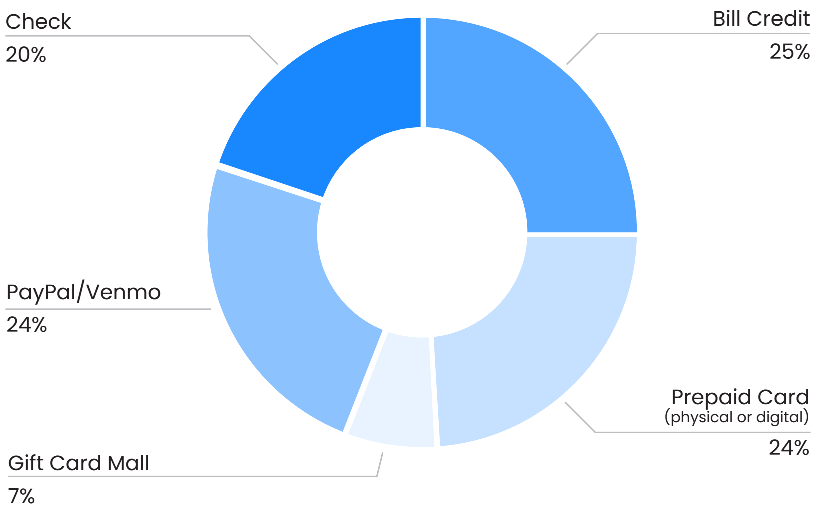


Fig. 10: Preferred payout methods for utility program incentives based on a survey of over 1,000 customers. (Source: Choice Digital)

Managing the next generation of flexible loads

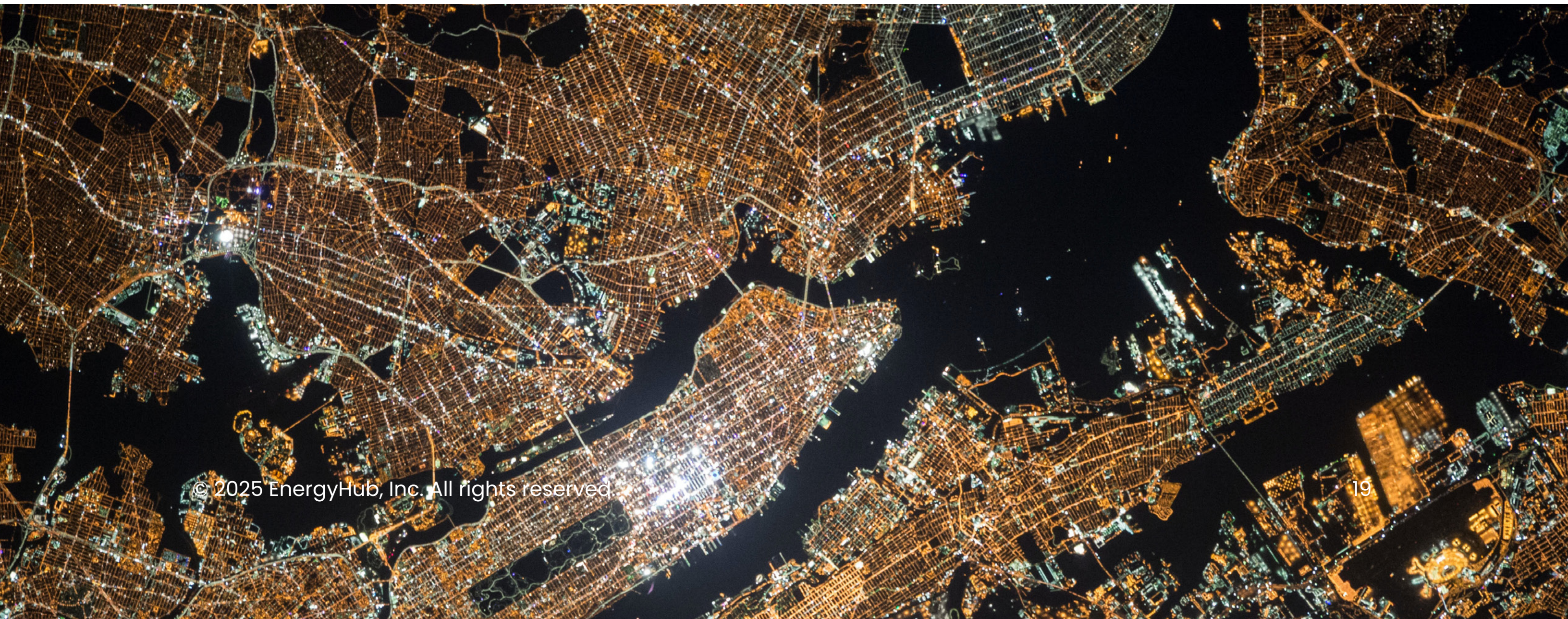
As technology advances, new DER types and controllable loads are emerging at the grid edge. To stay ahead, utilities should be thinking beyond the traditional thermostat, battery, and EV mix and preparing to integrate a broader range of behind-the-meter assets into one cross-DER VPP, including:

- Water heaters and pool pumps, which offer seasonal and daily load shifting potential
- Mini-split heat pumps and room ACs, which can build on existing BYOT programs
- Large commercial and industrial (C&I) loads, including building management systems (BMS) and switch-based aggregations, which can contribute significant capacity but may not offer device-level visibility
- Data centers and other large behind-the-meter assets, which can increasingly participate as controllable load-modifying resources

Together, levering these diverse DERS as one resource represents the next frontier of demand flexibility. But unlocking their full value will require a platform built to handle the complexity, scale, and variety of these emerging asset classes. That's where an Edge DERMS becomes essential, allowing utilities to:

- Normalize and coordinate dispatch across diverse device types within a single a platform
- Manage limited-visibility and third-party resources alongside directly integrated assets
- Integrate with Grid DERMS, aggregators, and other platforms for greater visibility and control

With the right Edge DERMS in place, utilities can ensure they're ready not just for today's flexible loads, but also tomorrow's.



Key takeaways for utilities

1. **Integrated DER portfolios are expanding VPPs' potential**
   Tapping into the full value of VPPs hinges on integrating diverse DER types like thermostats, batteries, and EVs to deliver precise load shapes and extended dispatch, enabling utilities to address both local grid constraints and bulk system needs while ensuring customer comfort and satisfaction.

2. **Data-driven recruitment and retention strategies are now essential capacity levers**
   As VPPs scale, customer churn and enrollment barriers can quickly erode capacity gains. Utilities employing proactive, data-driven customer engagement strategies can retain significant megawatts and avoid the costs of new resource acquisition.

3. **Advanced dispatch strategies are unlocking new value streams**
   Sophisticated dispatch tactics like smart events are now increasing event duration, relieving distribution-level strain, and reducing snapback all while improving customer experience. This precision enables VPPs to address increasingly complex grid and market needs.

4. **VPPs are evolving from seasonal to year-round flexibility resources**
   With grid peaks broadening across seasons and parts of the day, utilities are actively expanding the role of VPPs from emergency summer programs to year-round resources capable of flexible, daily dispatch. This evolution, supported by trends like surging battery attachment rates and managed EV charging, positions VPPs as a cornerstone of an adaptive, reliable modern grid.

Unlock the future of flexibility with EnergyHub

The coming years will see continued rapid growth for VPPs as utilities navigate increasing capacity challenges and regulatory requirements. Edge DERMS platforms will play a central role in enabling this future, providing the sophisticated capabilities needed to manage complex portfolios of distributed resources. By embracing these technologies today, utilities can build the flexible, resilient, affordable grid required to meet tomorrow's energy challenges.

EnergyHub helps utilities build and manage the next evolution of grid-aware, cross-DER VPPs in a single platform.

With EnergyHub's end-to-end software and services, utilities can achieve grid flexibility, reliability, and affordability through large-scale customer-centric program participation and cross-DER optimization — delivering more grid services than individually managed DER programs.

Learn more about the EnergyHub Edge DERMS and schedule a demo.

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info@energyhub.com | www.energyhub.com