U.S. DEPARTMENT OF
ENERGY

Pathways to Commercial Liftoff: **Virtual Power Plants 2025 Update**

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Comments

The Department of Energy welcomes input and feedback on the contents of this Pathway to Commercial Liftoff Report. Please direct all inquiries and input to liftoff@hq.doe.gov. Input and feedback should not include business sensitive information, trade secrets, proprietary, or otherwise confidential information. Please note that input and feedback provided is subject to the Freedom of Information Act.

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Purpose of Liftoff Reports

The United States (U.S.) Department of Energy (DOE) has published a series of reports on The Pathways to Commercial Liftoff for emerging clean energy technologies. These Liftoff reports provide a roadmap for how the public and private sector can collectively accelerate the commercialization of the technologies needed to decarbonize the U.S. economy. Given the constantly and rapidly evolving market, technology, and policy environment, these reports are designed to be "living documents" and will be updated as the commercialization outlook on each technology evolves.

Spearheaded by DOE's Office of Technology Transitions (OTT), these Liftoff reports reinforce dialogue across not only DOE, but also other Federal departments and agencies. They build upon learnings from DOE investments and continued engagement with industry stakeholders. DOE continues to solicit input through industry forums, requests for information, and other interactions. Direct public input can be submitted via email to liftoff@hq.doe.gov.

Objectives and Scope of Virtual Power Plant Update

DOE published the **Pathways to Commercial Liftoff: Virtual Power Plants** report in September 2023. Since that publication, Virtual Power Plant (VPP) adoption has grown; new VPP deployments, new insights and analyses into benefits, and new tools and resources from within and outside DOE have emerged. However, deployment still needs to accelerate in the U.S. to reach 80-160 GW of VPPs (10-20% of peak load) that contribute to an affordable, reliable, and secure grid for all Americans.

This Update supplements – but does not replace – the original 2023 VPP Liftoff Report by providing additional real-world examples, new resources, and updated industry insights that support VPP deployment. This report aims to (1) communicate the differential value proposition of VPPs in meeting near-term grid challenges compared to alternatives and (2) provide proven solutions to inspire and inform near-term actions that can accelerate progress towards Liftoff.

Please reference the 2023 VPP Liftoff Report for the following:

- VPP and Distributed Energy Resource (DER) definitions
- VPP value proposition
- Associated business models
- Technology in use
- Deployment potential
- Five imperatives for VPP liftoff, associated challenges, and potential solutions

Terminology

VPPs are aggregations of DERs that can balance electricity demand and supply and provide utility-scale and utility-grade grid services.[i] This report uses the term 'Virtual Power Plants' (VPPs) given it is the predominant term used in the industry, though it recognizes that other organizations use varying terms to describe similar grid assets. The National Association of Regulatory Utility Commissioners (NARUC) uses aggregated DERs (ADERs) to describe groups of DERs capable of providing one or more services to the electric grid through dispatch or control.[ii] Electric Power Research Institute (EPRI) uses the term distributed energy resource aggregations (DERAs). Other industry actors use the term distributed power plants (DPPs). This report's definition of Virtual Power Plants includes grid assets that meet the definition of all these terms, including traditional demand response (DR).

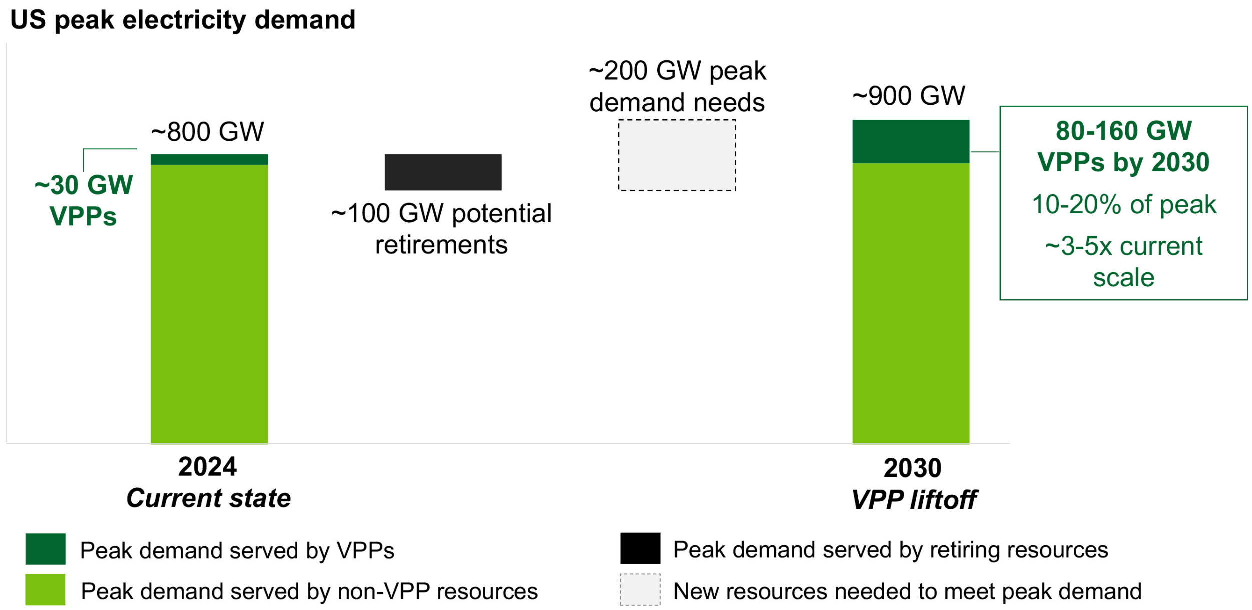
Executive Summary

Virtual Power Plants (VPPs) are solutions that can be deployed at scale in a short timeframe to maximize the use and value of existing grid infrastructure, minimize costs to ratepayers, and ensure a resilient, reliable, and secure grid for all Americans.

Recall from the 2023 Liftoff Report

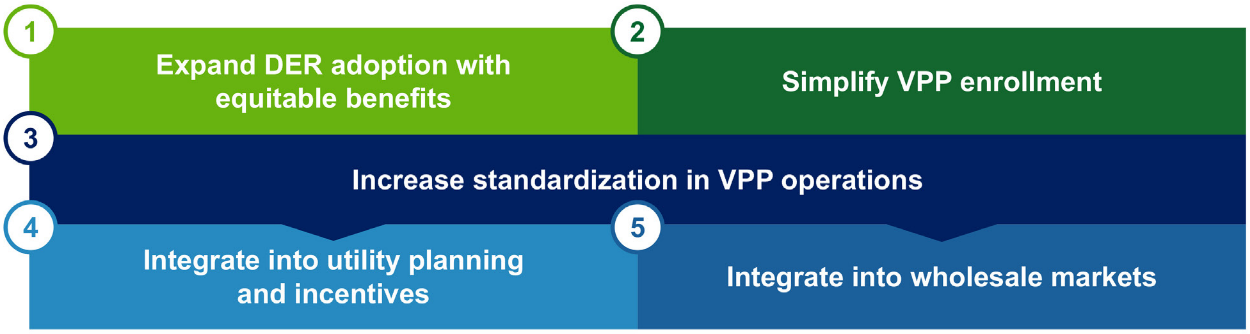
VPPs are aggregations of distributed energy resources (DERs) such as rooftop solar with behind-the-meter (BTM) batteries, electric vehicles (EVs) and electric water heaters, smart buildings and their controls, and flexible commercial and industrial (C&I) loads that can balance electricity demand and supply, as well as provide utility-scale and utility-grade grid services.

VPP liftoff



Deploying 80-160 GW of VPPs (enough to serve 10-20% of peak load) by 2030 could support rapid load growth while reducing overall grid costs. Although VPP scale has grown over the past year to 33 GW across North America[iii], the pace of deployment must accelerate to achieve liftoff.

Achieving liftoff will require progress on five imperatives:



Since DOE published the 2023 VPP Liftoff Report in September 2023, the pressures on the U.S. electric grid have intensified.

- **Reliability:** Peak demand is expected to increase from approximately 800 GW in 2024 to approximately 900 GW in 2030 due to growth in energy-intensive data centers, domestic manufacturing, and electrification of transport and heating.[iv]
- **Affordability:** Utility capital investments for the transmission and distribution grid have grown by 10.8% and 14.6% respectively from 2022 to 2023.[v] Capital investments are only expected to continue growing[vi] to meet rising load growth and replace aging assets, putting upward pressure on future electricity costs for ratepayers. This increases the importance of ensuring cost-effective grid investments to mitigate cost increases for ratepayers.
- **Resilience:** The U.S. experienced a record 28 'billion-dollar'[1] extreme weather events in 2023 that caused $95B of damage and injury.[vii] These extreme weather events are responsible for 75-80% of U.S. power outages for households and businesses.[viii]

VPPs are among the critical solutions to meet the pressing challenges the grid faces today and in the near term to keep electricity rates affordable while maintaining grid reliability and resilience.

Utilities, aggregators, policymakers, regulators, and other industry partners are taking action to implement solutions against each of the five imperatives for VPP liftoff. Replicating these proven solutions across the country could accelerate VPP deployment to reach liftoff by 2030.[2]

Expanding DER adoption with multifaceted benefits

Upfront incentives that stack across available Federal, state, city and tribal programs, inclusive utility investments, and partnerships with community-based organizations are strategies helping all communities today realize the reliability, resiliency, and affordability benefits from DERs and VPPs.

For example, San Diego Community Power's Solar Battery Savings program uses upfront, stackable incentives to provide the opportunity for no-cost solar panels and batteries for underserved communities.

Simplifying VPP enrollment

In addition to the ~30 GW of VPP capacity already enrolled today, enrolling 30-50% of the 150-200 GW of *new dispatchable* DER capacity that is projected to be added to the grid between now and 2030 could achieve liftoff nationally.

Utilities, regulators, and policymakers are harnessing existing and expected DER capacity and achieving best-in-class enrollment rates by pre-enrolling customers in VPP programs with opt-outs (instead of the opt-in method that is most common today), simplifying messaging about program benefits, and offering ongoing participation incentives.

For example, Arizona Public Service's marketplace pre-enrolls customers at point of purchase into their smart thermostat Cool Rewards program (9,290 pre-enrollments processed as of October 2024).

1 Billion-dollar events are weather and climate events that caused more than $1B of damage.

2 For additional information on challenges and potential solutions for each of the imperatives, see Chapter 4 in the 2023 VPP Liftoff Report (pages 38-52).

Increasing standardization in VPP operations

New efforts across the industry are designing standards for utility-aggregator interfaces, aggregator-DER interfaces, cybersecurity responsibilities, and other aspects of VPP operations.

Even in the absence of standards, many utilities are capturing near-term value now with basic VPP configurations that require less than $1M in upfront investment and can be deployed in less than six months to deliver valuable peak shaving benefits. Leading utilities leverage basic VPPs as the foundation for more sophisticated models (which require enabling hardware and software) that deliver distribution grid benefits in addition to bulk system-level peaking capacity.

- *Example standardization efforts include the development of a model grid services contract from the North American Energy Standards Board and device interoperability standards from the Mercury Consortium.*
- *An example of a rapid, utility-led VPP deployment is National Grid's ConnectedSolutions program, which launched in under four months and now has 250 MW of peak shaving capacity in MA and NY.*

Integrating into utility planning and incentives

Most utilities can implement some form of VPPs today without any policy or regulatory change. However, VPP deployment has been highest in areas where state regulators and policymakers have implemented VPP-supportive actions.

Regulators are motivating utility action that is more in line with ratepayer interest by establishing cost recovery pathways for VPP-related investments, improving system planning, supporting DER deployment and aggregation, and enhancing VPP operation and compensation models. Policymakers are using legislation to accelerate deployment by establishing a direction and removing ambiguity about VPP goals and other program parameters for utility regulators and other stakeholders.

- *An example of VPP-supportive regulation is the New York Public Service Commission's Value of Distributed Energy Resources (VDER) mechanism to compensate DERs based on their system value.*
- *An example of VPP-supportive legislation is a bill signed by Colorado's legislature in May 2024, SB24-218, that requires the state's largest Investor-Owned Utility (IOU), Xcel Energy, to submit a VPP plan to the Colorado Public Utility Commission.*

Integrating into wholesale markets

CAISO and ISO-NE have fully complied with the requirements of FERC Order 2222[3], theoretically unlocking wholesale market participation from a much wider range of DERs in those regions. Challenges to integrate VPPs into wholesale markets remain, particularly on data access, metering requirements, and participation models. However, market operators, state policymakers, and regulators, can collaborate to learn from each other's experiences and quickly iterate to enable VPPs to meet near-term grid capacity needs at lower costs for ratepayers.

→ *For example, CAISO, NYISO, PJM, and SPP allow participants that meet certain criteria to use calculated telemetry readings based on sampling rather than requiring direct telemetry for each DER to participate. This allows a greater number of DERs to participate given relaxed telemetry requirements and reduced participation costs.*

Public and private sector stakeholders are taking action. This report includes over 75 examples of actions that utilities, aggregators, OEMs, regulators, policymakers, ISO/RTOs, ecosystem partners, and others are implementing today as well as **over 60 complementary programs and resources** that DOE and its collaborators have established to accelerate deployment. Stakeholders can adopt and adapt demonstrated best practices from across the country and leverage existing tools and resources to achieve VPP liftoff and contribute to a reliable, affordable, and resilient grid.

3 In September 2020, FERC (Federal Energy Regulatory Commission) approved Order 2222, which required the six FERC-jurisdictional Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) to allow participation of VPPs (referred to in the Order as "DER Aggregations") in wholesale markets. The six FERC-jurisdictional ISO/RTOs are California Independent System Operator (CAISO), Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), PJM Interconnection (PJM), and ISO New England (ISO-NE).

Introduction: Why VPPs now?

Key takeaways

- Rapid growth in peak electricity demand by 2030, capital-intensive transmission and distribution (T&D) upgrades to accommodate expected load growth, and outages due to extreme weather events and aging infrastructure are placing disproportionate pressure on grid reliability, affordability, and resilience.
- VPPs are cost-effective solutions for balancing the grid that can be deployed at scale within six months to maximize the use and value of existing infrastructure, minimize costs to ratepayers, and ensure a resilient, reliable, and secure grid for all.

Since the VPP Liftoff Report was published in September 2023, the near-term pressures on the U.S. electric grid have intensified. Forecasts of U.S. peak demand growth have increased sharply in the past year due to a surge in interest in artificial intelligence (AI) applications powered by energy-intensive data centers, hundreds of new domestic manufacturing site developments, and the continued electrification of transportation and heating. This increase in forecasted load growth will require greater utilization of local resources to satisfy electric power requirements. At the same time, recent extreme weather events have heightened awareness of the vulnerability of the grid and the need to invest in resilience. The culmination of these challenges necessitates historic investments to shore up the U.S. power system – costs that may fall on ratepayers already burdened by rising energy costs.

i. Near-term grid challenges

Reliability: *Rapid demand growth*

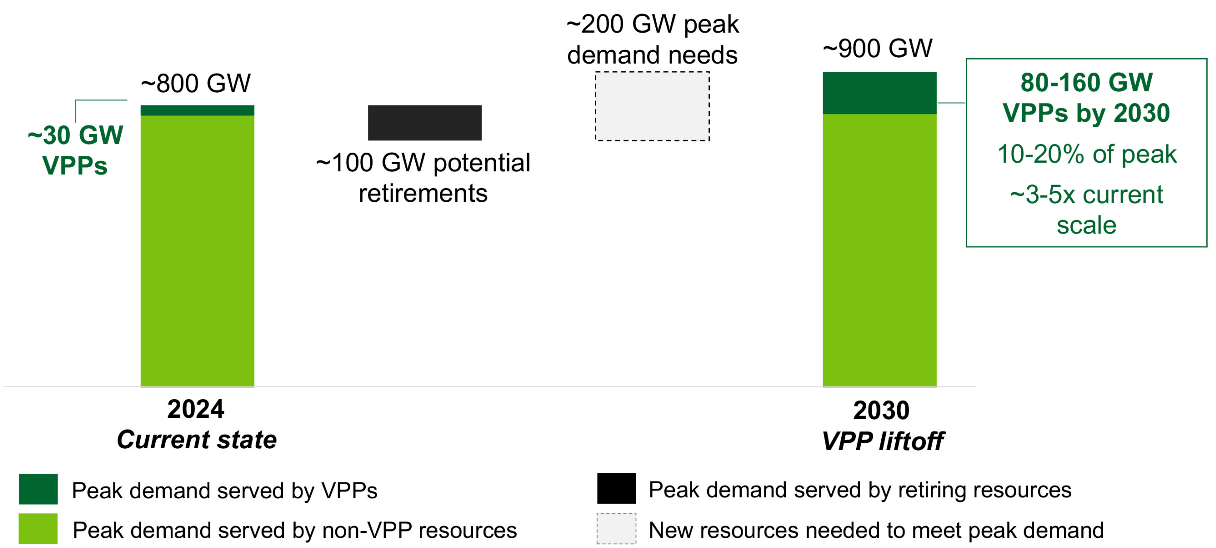
After two decades of flat electricity demand, the U.S. is returning to a period of rapid demand growth with total electricity demand expected to grow ~15-20% in the next decade.[4,5,ix,x] The 2023 VPP Liftoff report estimated that new resources serving over 200 GW of peak demand would need to be added to the grid by 2030 to meet demand growth and replace retiring resources. Since 2023, retirement schedules and growth forecasts have both shifted, but the net result of roughly 200 GW of peak demand needs by 2030 remains.

4 NERC forecasts from December 2024 suggest total electricity will increase from 150,540 GWh in 2024 to 176,040 GWh in 2034. Total electricity demand is measured over the course of a year and is distinct from peak demand, which is a point-in-time measurement.

5 See the DOE's Electricity Demand Growth Resource Hub for additional information about and DOE resources to support rising electricity demand.

VPP liftoff

US peak electricity demand



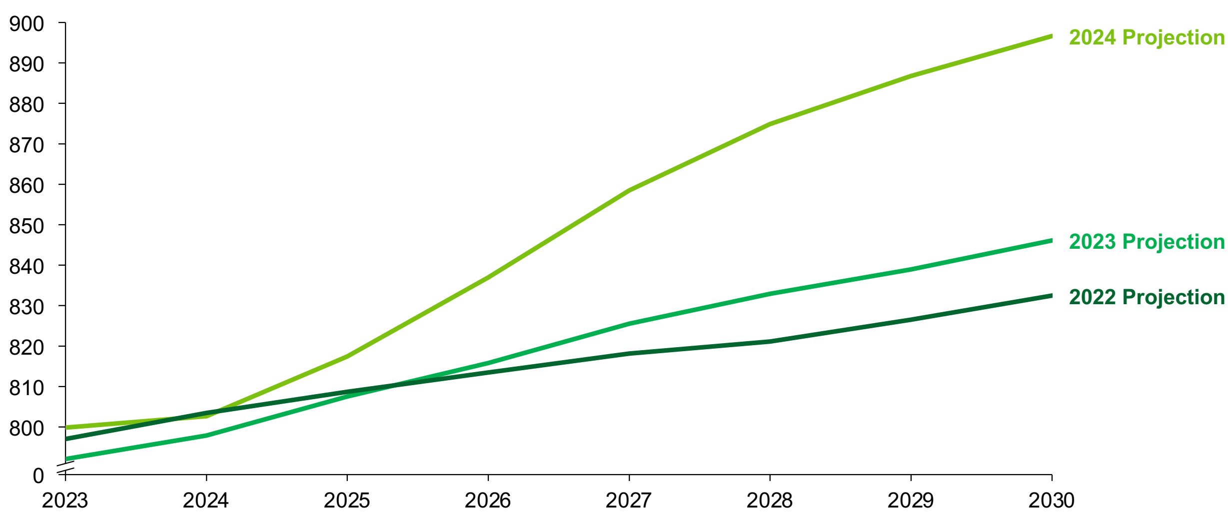
Note: NERC's Electricity Supply & Demand peak hour demand forecasts include 2024 peak summer demand as 803 GW and estimates 2030 peak summer demand to be 897 GW.[xi,xii,xiii] NERC's 2024 Long-Term Reliability Assessment estimates that 52 GW of generators are confirmed to retire by 2029, with anticipated and announced retirements estimated to be close to 100 GW by 2030.[xiv] For this reason, the need is estimated to be ~200 GW of firm capacity (~100 GW new peak demand + ~100 GW peak demand no longer served by retired assets, not accounting for planning reserve margin or the non-firm capacity de-rates of retiring resources). 30-60 GW estimate of VPP capacity in 2023 VPP Liftoff Report was adjusted to ~30 GW based on Wood Mackenzie's North America VPP Market Report,[xv] which estimates that there is 33 GW of VPP capacity in North America with the majority considered to be in the U.S.

Source: NERC 2024 Long-Term Reliability Assessment, NERC 2024 Electricity Supply & Demand data, Wood Mackenzie 2024 NA VPP Market Report

Demand growth reflects economic development, though the specific drivers of demand growth vary by region. At a national level, the three primary drivers of demand growth are data center development (including to support AI applications),[xvi] a surge in manufacturing investments (with over 900 new and expanded manufacturing facilities announced as of December 2024), and end-use electrification (e.g., transport, buildings, industrial).[xvii,xviii]

Demand growth forecasts continue to evolve rapidly. This uncertainty increases the importance of prioritizing the most cost-effective and flexible resources to serve rapidly changing conditions.[xix,xx]

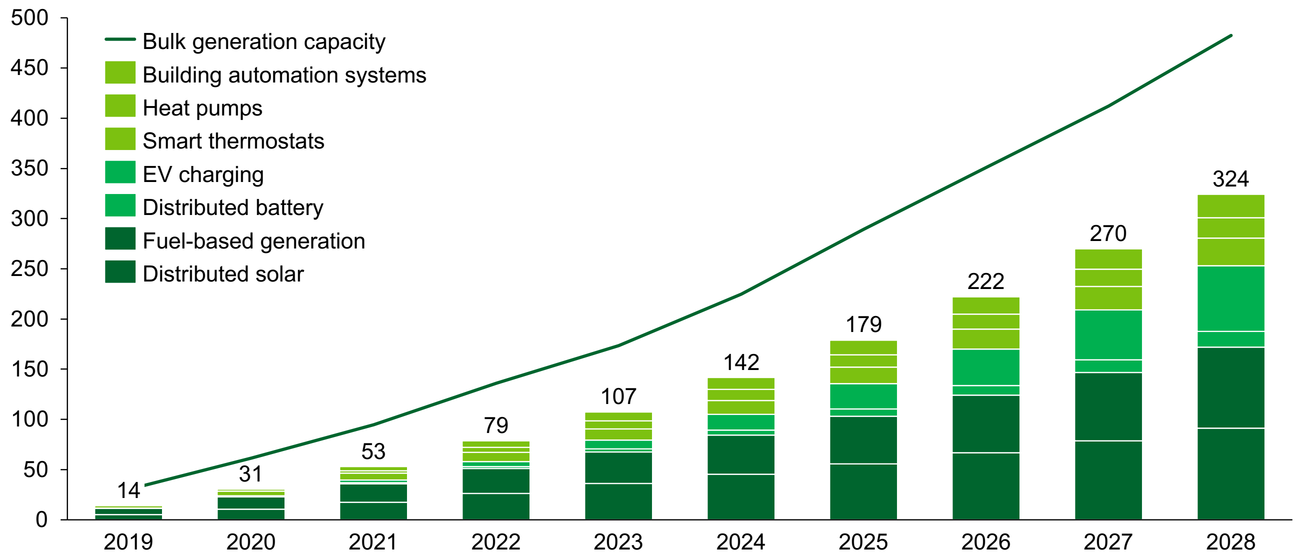
U.S. summer peak hour demand by year (2023-2030), GW



Source: NERC 2024 Electricity Supply and Demand data

Installed capacity of distributed energy resources (DERs) is forecasted to grow nearly as fast as forecasted bulk generation capacity in the next five years, with an incremental 217 GW of DERs expected by 2028.[xxi] DER growth is expected in every state, though the pace varies regionally, with growth likely to be concentrated in specific geographies. Without efficient management of these resources, such as with a VPP, expected growth of DER capacity at the grid-edge[6,xxii] in these regions could strain local, aging distribution systems and increase the cost to deliver electricity.

DER vs bulk generation capacity additions since 2019, GW



Source: Wood Mackenzie 2024 US DER Outlook

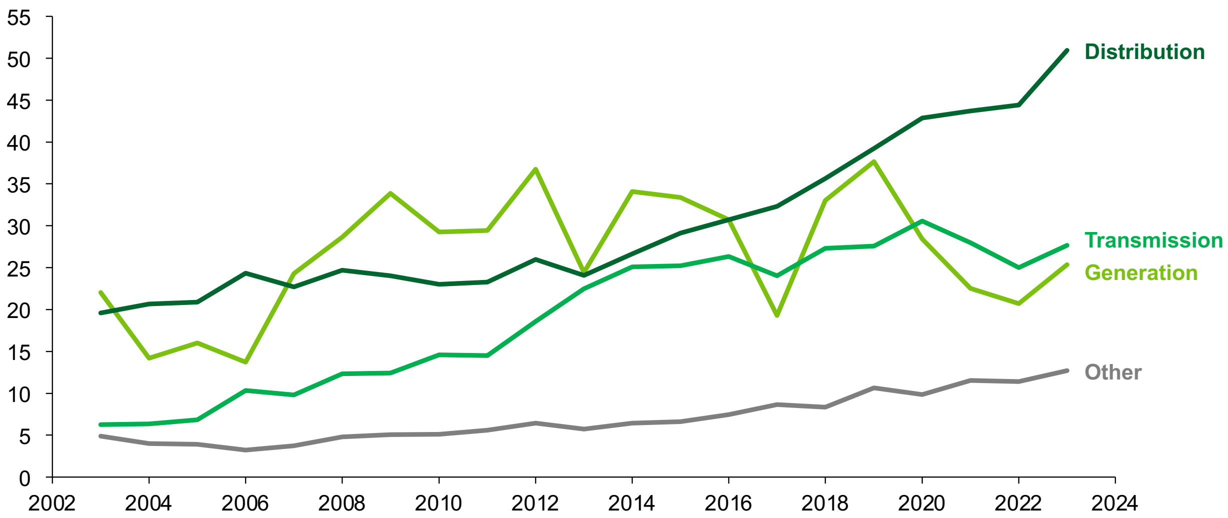
Affordability: *Upward pressure on customer costs from growing capital investments*

Capital investments in transmission and distribution (T&D) systems are growing to meet rising load growth and replace aging assets, impacting affordability. Over the last two decades, total utility spending on electricity generation has fallen, primarily due to lower fuel costs (e.g., growth in low-cost renewables, lower natural gas prices). However, these declines have been offset by a significant increase in T&D investment, particularly distribution investment, led by capital costs to upgrade, replace, and add new infrastructure.[xxiii]

Utility capital investments in the distribution system grew by 14.6% from 2022 to 2023; capital expenditures (versus operating & maintenance expenditures) now comprise the majority of spending for distribution infrastructure.[xxiv] In the U.S. Energy Information Administration's (EIA) 2023 Annual Energy Outlook (AEO 2023) projections, average combined transmission and distribution prices are expected to grow by 12% between 2023 and 2030 after accounting for inflation, even as total electricity prices decline.[xxv] Since the release of AEO 2023, load forecasts have increased and rising load growth will further increase grid investment needs. These higher grid investments put upward pressure on future electricity costs for ratepayers.

6 The grid edge is defined as the area where the electricity distribution system transitions between the utility and the end user. Additional details are included at DOE's Supercharging the Electric Grid Edge web page.

Annual U.S. capital expenditures by sector (2003-2023), billions of 2023 U.S. dollars ($)



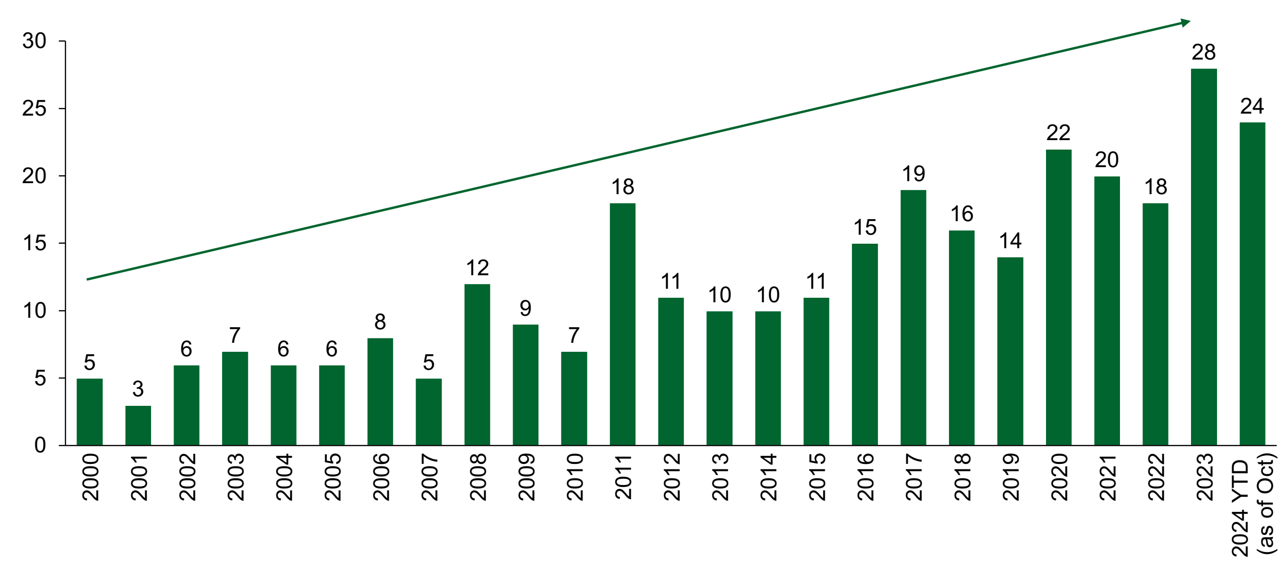
Source: FERC Form 1 (Electric Utility Annual Report)

Rising energy costs have a disproportionate impact on low-income Americans. Nearly one in four households in the U.S. was unable to pay their full energy bill for at least one month in the last year.[xxvi] Maintaining electricity affordability in the face of increasing utility transmission and distribution investments, which have increased from 10% of customer bills in 2005 to 24% in 2020,[xxvii] is particularly important for these households.

Resilience: *Increasingly frequent extreme weather events*

Increasingly frequent extreme weather threatens grid resilience. In 2023 alone, the U.S. experienced a record 28 separate billion-dollar climate disasters that caused $95B of damage and injury.[xxviii,7] 75-80% of U.S. power outages are due to extreme weather events, according to Climate Central.[xxix]

Number of billion-dollar climate and weather events, count / year (adjusted for inflation)



Source: NOAA Billion-Dollar Weather and Climate Disasters

7 Climate disasters disproportionately affect underserved communities, which already often have lower energy reliability than higher income areas.

ii. VPP value proposition

How VPPs address near-term grid challenges

Near-term grid challenge	VPP value proposition	Example
Reliability: Rapid demand growth	**Impact #1: VPPs provide valuable peak shaving benefits** 10-20% of 2030 peak demand could be served by VPPs	• **Portland General Electric's** VPP reduced peak demand load by 2% in 2024; PGE is targeting 25% of peak demand met by flexible load solutions by 2030.
	Impact #2: VPPs are quick to deploy Basic VPPs can be operationalized in <6 months to meet rapid growth	• **National Grid** launched its ConnectedSolutions program in under 4 months to provide peak shaving benefits.
Affordability: Upward pressure on customer costs from growing capital investments	**Impact #3: VPPs are low-cost solutions** VPP peaking capacity is 40%+ cheaper than a conventional peaker plant VPPs can reduce distribution costs by providing greater locational visibility and control VPPs can offset energy bills by compensating customers	• **ConEdison** deferred a $1.2B substation upgrade, spending $200M on DERs and demand reduction measures instead. • **United Power** used 95 MW of flexible DER capacity and improved grid visibility to reduce transformer outages from 25,000 min/year to near 0. • **San Diego Community Power** uses their Solar Battery Savings Program to incentivize customers to adopt residential batteries for daily dispatch to realize $5M of Resource Adequacy savings.
Resilience: Increasingly frequent extreme weather events	**Impact #4: VPPs improve grid reliability and resilience** Solar with batteries and/or fuel generator VPPs can provide backup power during emergencies	• **Duke Energy** spent $14.5M on a microgrid to provide reliable power to a rural town at a lower cost than alternatives. • **Green Mountain Power's** Zero Outages initiative plans to combine traditional resilience approaches with energy storage deployment through batteries and microgrids.

See 2023 VPP Liftoff Report pages 8-12 for detail on the VPP value proposition across resource adequacy, affordability, reliability & resilience, decarbonization & air pollution reduction, T&D infrastructure relief, community empowerment, and versatility & flexibility.[xxx]

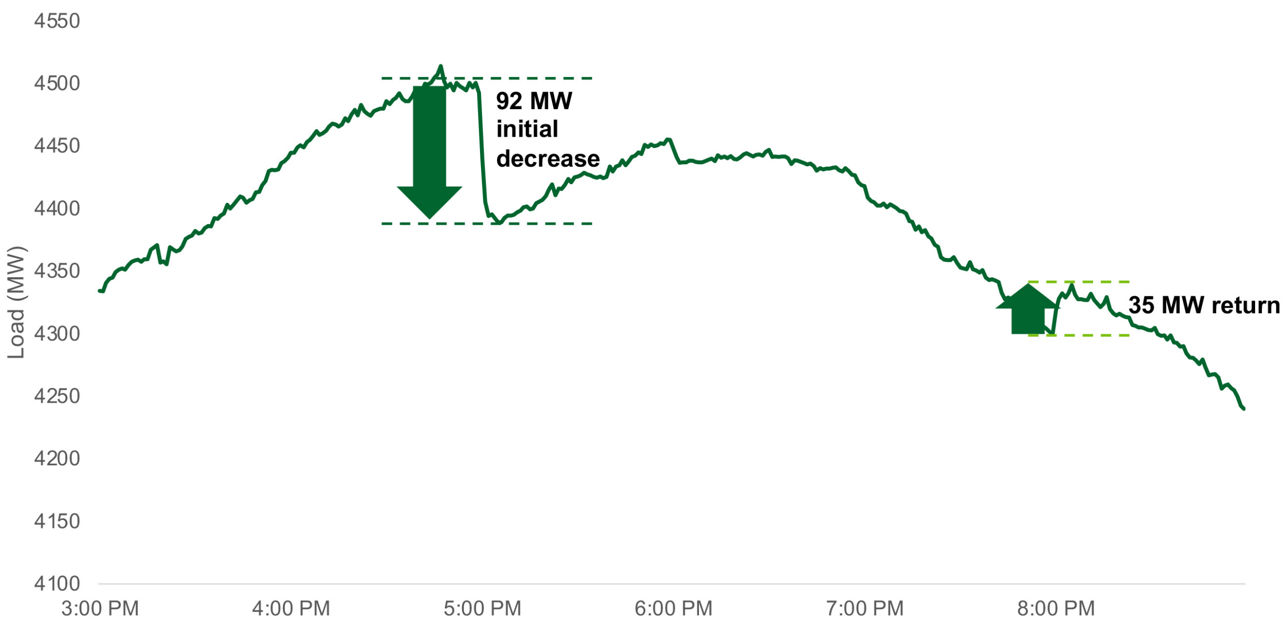
Impact #1: VPPs provide valuable peak shaving benefits

VPPs provide valuable peak shaving benefits to the grid. VPPs can aggregate DERs to serve, shift, and reduce energy demand to address growing peak demand needs and relieve grid capacity constraints. By more efficiently balancing the timing of demand with available supply, VPPs can address system constraints at the generation level (e.g., serve peak demand with storage DERs), at the transmission level (e.g., reduce peak demand when utility-scale supply is limited by transmission constraints), and distribution level (e.g., shift peak demand that threatens to exceed the safety limits of local equipment to earlier or later in the day).

One example of a utility taking advantage of this potential is **Portland General Electric (PGE)**. PGE plans to grow its VPP from serving ~2% of peak demand today to ~25% of peak in 2030.[8,xxxi,xxxii] PGE plans to increase its VPP capacity by encouraging greater participation from new and existing solar and storage assets, flexible customer loads, and customer back-up generation.

8 PGE has been growing their Customer Flexible Load programs and VPP capabilities for over two decades.

Bulk system impact from Portland General Electric's peak shaving program (August 14, 2023)



Source: Portland General Electric

Impact #2: VPPs are quick to deploy

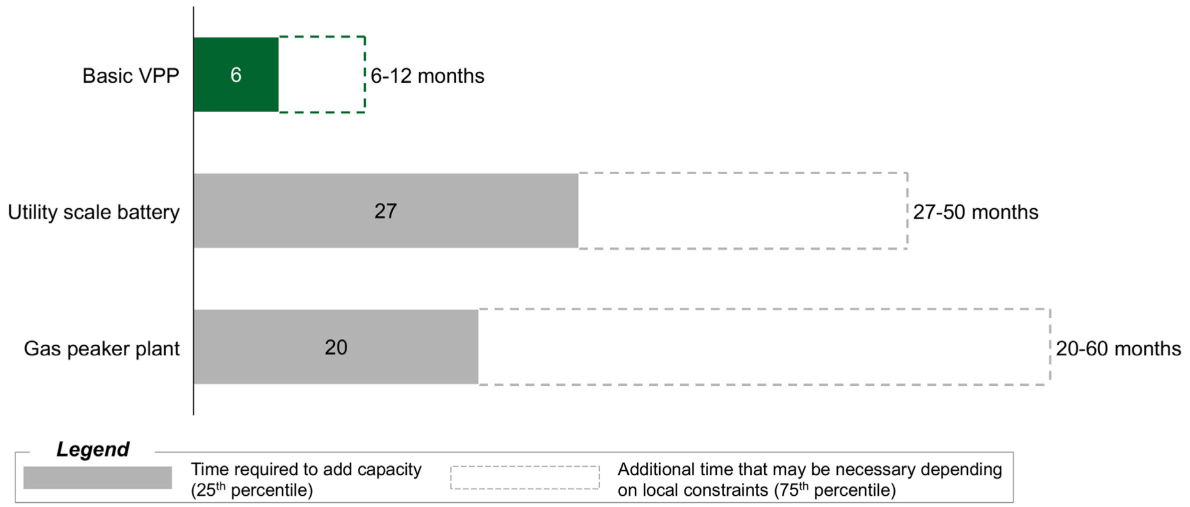
Basic VPPs that shave demand peaks can start operating within six months[xxxiii]; this can buy time for the construction of higher-capacity assets and increase the value of grid assets for which Americans have already paid. Basic VPP configurations[9] can leverage DERs that are *already on the grid* or expected to be deployed to serve as the foundation for fast-launching, large-scale VPP programs. Wood Mackenzie estimates that U.S. consumers and businesses will install 324 GW of new DERs between 2019-2028, representing 137 GW of curtailable capacity[10] if enrolled in VPPs.[xxxiv]

Traditional approaches to increasing grid capacity (utility-scale generation, transmission, distribution) rely on investing in large, centralized physical infrastructure, such as building fossil fuel-powered peaker plants and upgrading transformers. These upgrades are facing lengthening delays for several reasons. New electricity generation facilities are waiting four to six years in transmission interconnection queues before they can connect to the grid to supply power.[xxxv] Long distance greenfield transmission projects often face lengthy permitting timelines, with review periods that average 4.3 years and can extend up to 11 years.[xxxvi] Lead times to procure large transformers (greater than 500 MVA) are averaging three years due to supply chain issues.[xxxvii]

9 For an explanation of basic vs. more sophisticated VPP configurations, reference Chapter 3: Increasing standardization in VPP operations.

10 Curtailable capacity includes flexible capacity from smart thermostats, heat pumps, buildings with energy management systems, and export potential from batteries.

Timeline to add 20 MW of dispatchable peaking capacity, months



Note: Industry participant interviews informed the timeline for basic VPPs, supported by RMI's Reliability Brief from July 2024[xxxviii]. For utility scale battery and gas peaker plant, the timeline includes time from interconnection request to project Commercial Operations (COD) for projects with 2017-2023 CODs; displaying 25th to 75th percentile range. Median values are 40 months for battery and 42 months for gas projects.[xxxix]

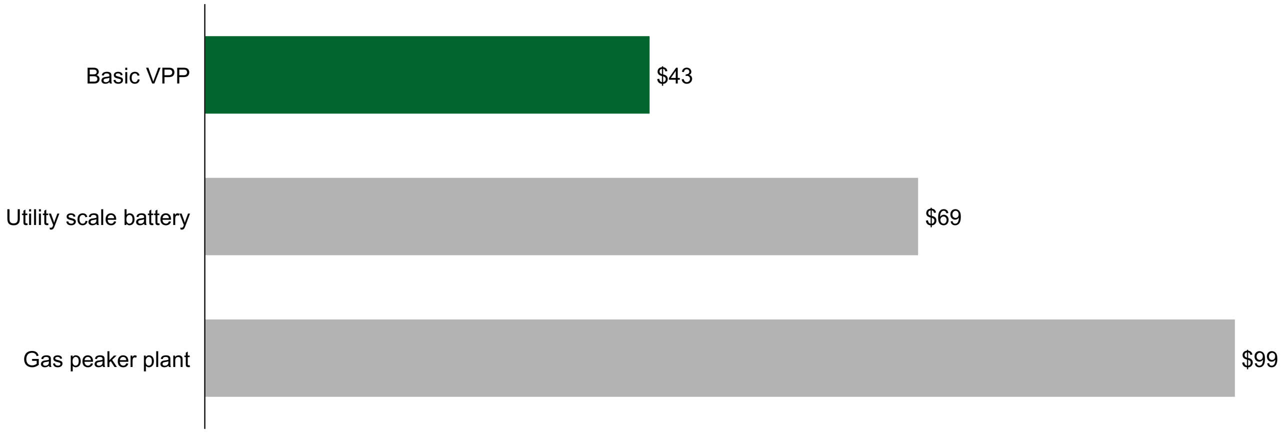
Source: Industry interviews, RMI Reliability Brief, Lawrence-Berkeley National Lab's 2024 Queued Up Report

As an example of how VPPs can address rising electricity demand, **NRG Energy** and **Renew Home** recently announced plans to launch a 1 GW VPP in Texas by 2035, equivalent to 12 gas-fired peaker plants, by leveraging flexible demand from smart thermostats. This announcement comes just months after the Electricity Reliability Council of Texas (ERCOT) revised its 2030 load growth forecasts to 148 GW[xl], **an increase of 40 GW from last year's forecast.**[xli] Rapid peak demand growth requires solutions that can be deployed rapidly.

Impact #3: VPPs are low-cost solutions

VPPs are a cost-effective peak capacity resource relative to traditional investments, both on the bulk power grid and the distribution grid. On the bulk power grid, procuring new system-level peak capacity from a VPP can be lower cost than procuring the same capacity from a natural gas peaker plant or utility-scale battery. These savings, as well as reduced distribution and transmission costs, accrue to all ratepayers (not just VPP participants). An RMI study of an example utility system in 2035 found that a VPP-enabled portfolio reduces net power generation costs by 20% or roughly $140 per household (including non-participating ratepayers) per year compared to a baseline scenario.[xlii] In New York, **ConEdison** deferred a $1.2B substation upgrade in 2014, spending $200M instead on DERs and demand reduction measures as part of the Brooklyn Queens Demand Management Program.[xliii] Beyond these system benefits for all ratepayers, additional financial benefits accrue to customers enrolled in the VPP in the form of incentive payments.

Comparison of net cost to an example utility of providing 400 MW resource adequacy across three options, Net cost per kW-year



Note: Values for 400 MW of peaking capacity are shown in $/kW-yr. The VPP analyzed consists of smart thermostats, smart water heating, home EV managed charging, and BTM battery demand response. Modeled equipment subsidy costs to utility are $75 for smart thermostats, $315 for smart water heaters, and $0 for EV charging and BTM batteries. Marketing costs assumed at $50 per device. Utility studied is assumed to have 50% renewable generation mix, with resource adequacy needs in summer and winter. 8760 hours were considered, and resources must be able to operate in 63 peak hours (when top 400 MW are needed) spanning 7 months, for 7 consecutive hours at a time. Benefits of emissions reduction and resilience are not shown; when included, VPP net cost is lower, though actual emissions impact will vary by local grid mix.[xliv]

Source: Brattle Group's Real Reliability: The Value of Virtual Power Report

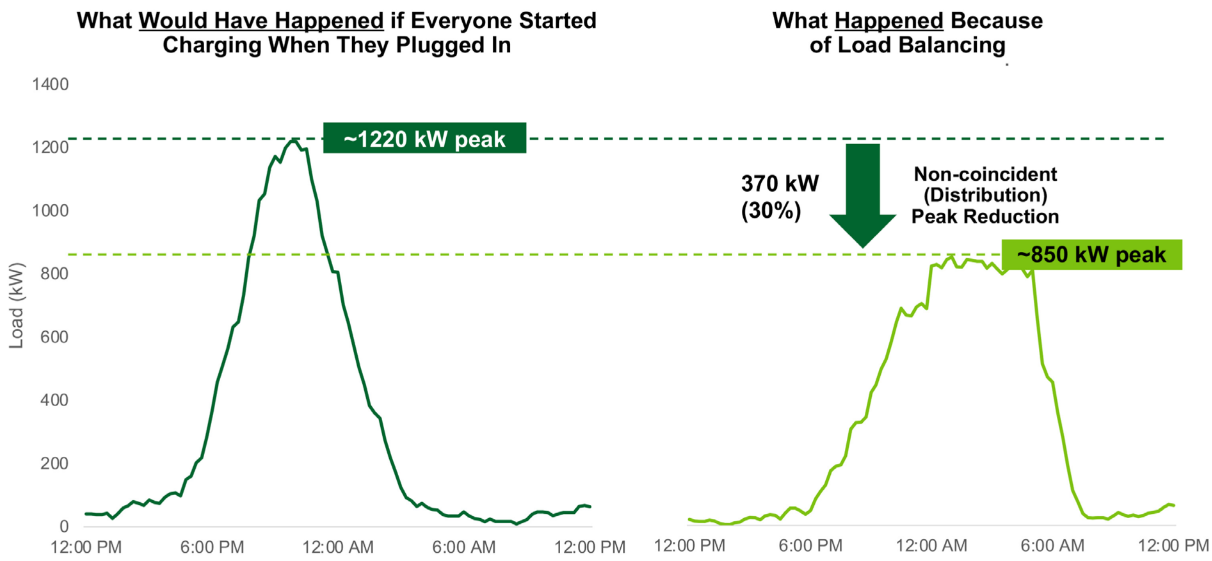
On the distribution grid, VPPs can help utilities defer costly system upgrades by shaving localized peak loads that would otherwise trigger the installation of new equipment. Many utilities facing rising demand are using VPPs as an interim solution until distribution grid capacity upgrades are absolutely necessary, saving ratepayers money in the meantime. A whitepaper co-authored by **AES Indiana** and **Camus Energy** found that deploying visibility solutions to detect where EVs are located on the grid and transitioning to grid-optimized managed charging programs could defer upgrades to 85% of eligible feeders and service transformers for an average of 8.5 years compared to a business-as-usual scenario. Capital cost savings from deferring upgrades were estimated to avoid close to $1B in cost overruns over the next decade, with savings going directly to consumers.[xlv] AES Indiana is *one* utility with 500,000 utility meters. While service areas across the U.S. are diverse, extrapolating to the 150 million meters across the U.S. would imply **significant potential savings[11] by deferring capital investments and optimizing the use of the existing electricity system across generation, transmission, and distribution.[12,xlvi]**

Baltimore Gas & Electric's (BGE) managed charging program demonstrates the peak shaving potential of VPPs on the distribution grid. With a feeder-level participant group of 880 vehicles, BGE's managed charging program created a non-coincident peak reduction of 30% while still serving customer's transportation energy needs. BGE plans to grow its managed charging program from 3,253 residential customers to 30,000 customers by 2027.[xlvii,xlviii]

11 A rough extrapolation of this example to the 150 million meters across the U.S. would imply potential savings of $300 billion over the next decade by deferring capital investments.

12 An LBNL study mentioned the U.S. building sector alone could avoid over $100B per year in power sector costs by leveraging demand-side solutions (e.g., smart thermostats, electric heat pumps, smart control systems) by 2050.

Distribution grid impact from Baltimore Gas & Electric's managed charging program



Source: WeaveGrid

Impact #4: VPPs improve grid reliability and resilience

VPPs provide resilience benefits that traditional generation assets cannot provide—and at a lower cost than alternatives. VPPs that include solar and storage or fuel generators at a household or commercial and industrial site provide power with far fewer possible points of failure than power supplied from a distance by a traditional power plant. VPPs also have the potential to help utilities restore power to impacted areas more quickly, reducing the length of outages for customers impacted by severe weather events.

Much of the grid hardening work in disaster-prone areas has been undergrounding power lines. Although this has been effective in some areas, including pockets of Florida during Hurricanes Helene and Milton[xlix], it has come at a high cost. The **Public Service Commission of Wisconsin** estimates that undergrounding a 69-kilovolt line costs ~5x more per mile versus aboveground installation.[l] Alternatively, utilities are using DERs and VPPs at the end of vulnerable transmission or distribution lines to ensure reliable power at a lower cost than undergrounding lines.

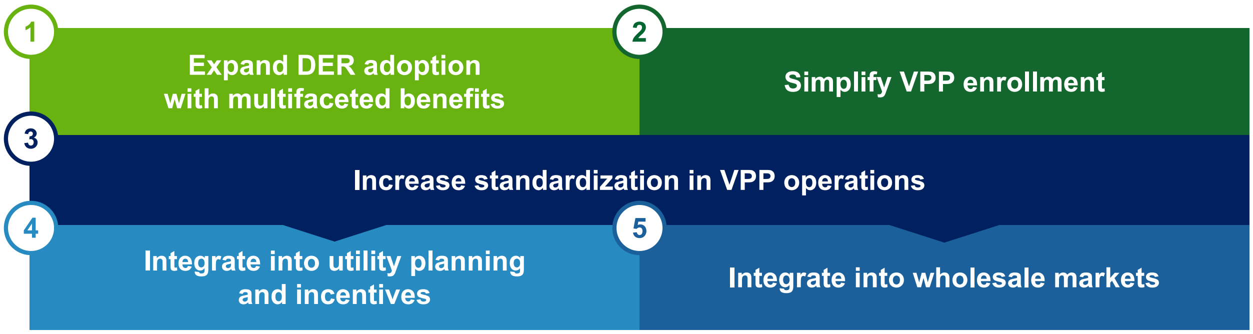
For example, in 2023, **Duke Energy** installed 2 MW of solar power and 4.4 MWh of battery storage along with VPP-enabling technology to create a microgrid in Hot Springs, a town of about 535 residents in North Carolina. With a cost of $14.5M, the microgrid was deemed less expensive than the grid upgrades that would have been required to provide reliable power for the rural town. For the residents of Hot Springs, the microgrid offered resilience; for the surrounding communities, it provided energy and bulk system benefits, such as frequency and voltage regulation and capacity during system peaks.[li] With the Hot Springs microgrid and VPP-enabling investments, Duke Energy restored power to residents quickly after Hurricane Helene in 2024, even though the local substation was severely impacted by flooding.[lii]

iii. Imperatives for VPP liftoff

VPPs are solutions that can be deployed at scale in a short timeframe to maximize the use and value of existing grid infrastructure, minimize costs to all ratepayers, and ensure a resilient, reliable, and secure grid for all Americans.

Deploying 80-160 GW of VPPs (enough to serve 10-20% of peak load) by 2030 could support rapid load growth while reducing overall grid costs. VPPs are not new and have been operating with commercially available technology for years.[liii] While VPP scale has grown over the past year to 33 GW across North America[liv], deployment must accelerate to achieve liftoff by 2030.

As explained in the 2023 VPP Liftoff Report, achieving liftoff for VPPs will require progress on five imperatives:



Utilities, policymakers, regulators, and other industry partners all have a role to play in accelerating action against these five imperatives to address the challenges hampering VPP adoption today.

The potential for VPPs to meet near-term grid needs cost-effectively for American ratepayers represents an urgent call to action for all grid stakeholders to do their part in advancing deployment. Building on the foundation of the 2023 VPP Liftoff Report, the remainder of this Update will explore each of the five imperatives. Starting with a brief overview of the imperative, each chapter and its corresponding appendix will focus on presenting new VPP case studies, new insights into VPP benefits, and new tools and resources from the Department of Energy and broader industry that can support power sector decisionmakers and accelerate progress towards VPP liftoff.

Chapter One: Expanding DER adoption with multifaceted benefits

Key takeaways

- DER adoption today is a fraction of its potential (e.g., 3.5-3.8% of households have rooftop solar, <1% have BTM batteries, and 12.9-13.8% have smart thermostats). Low DER adoption will limit available capacity for VPPs.
- The main barriers to scaling DER adoption include high upfront costs with limited low-cost financing options, split incentives between property owners and tenants, and knowledge gaps on available programs and incentives, all of which disproportionately affect underserved communities.
- Upfront incentives that stack across available Federal, state, city, and tribal programs, inclusive utility investments, and partnerships with community-based organizations are strategies helping communities today participate in reliability, affordability, and resilience benefits from DERs and VPPs.

1.i. DER adoption today

DER adoption today is a fraction of its potential (e.g., 3.5-3.8% of households have rooftop solar[lv], <1% have BTM batteries, and 12.9-13.8% have smart thermostats[lvi,lvii]). Low DER adoption will limit available capacity for VPPs and reduce the speed at which VPPs can be deployed at scale, delaying potential benefits to ratepayers and the grid. Barriers to accessing DERs include high upfront costs with limited low-cost financing options, 'split incentive gaps' between property owners and tenants for single-unit and multi-unit dwellings[13], and knowledge gaps on available incentives and programs. These barriers are even more pronounced for underserved communities.[14]

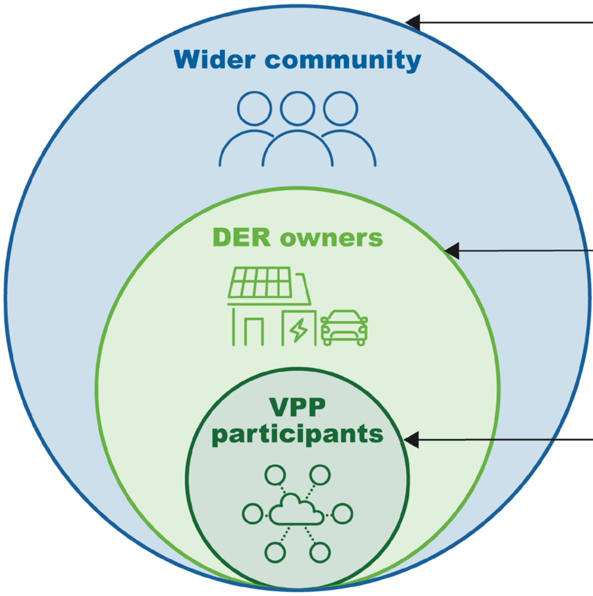
1.ii. Layers of benefits

Ensuring all groups – DER owners, VPP participants, and the wider community – can participate and realize benefits from DER and VPP deployment is critical to realizing reliability, affordability, and resilience benefits for individual households and businesses, and the overall grid.

13 The split incentive gap refers to the tension between property owners, who would be expected to pay for a distributed energy resource, and tenants, who would benefit from lower energy costs. This incentive misalignment is a significant barrier to DER adoption in rented properties.

14 See 2023 VPP Liftoff Report pages 13-17 on the rates of DER penetration and how DER adoption plays a role in VPPs. See pages 39-42 for additional discussion on the barriers for DER adoption and potential solutions

Layers of potential benefits from deploying VPPs



Access to community-wide benefits

Distribute benefits of lower energy bills, reduced impact of outages, improved air quality outcomes, and local workforce development opportunities to participating and non-participating ratepayers.

Access to DER ownership

Make DERs more affordable and increase access to financing so all households and businesses can reap benefits of DER ownership such as lower energy bills, backup power, and improved air quality.

Access to VPP participation

Reduce barriers to VPP enrollment, including lack of accessible programs and limited knowledge of existing programs, to reward participants with incentives that offset the cost of DER ownership.

- **Access to community-wide benefits: Retain and redirect cost savings from VPP deployment (vs. alternative CapEx heavy investments) toward reducing all utility customer bills, not just for those participating in VPPs.** Compensating for the total value of all the services VPPs provide to the grid is a way to make sure adoption is beneficial for DER adopters and all ratepayers, but few holistic DER/VPP value frameworks exist today. Additional benefits can be intentionally directed to underserved communities to help address those communities' higher energy burdens[15], increased incidence of outages, and lower air quality outcomes.[16]

- **Access to DER ownership: Make DERs more affordable and increase access to financing so the benefits of DER ownership (e.g., reduced energy bills from efficient appliances, backup power options from batteries and generators, and improved air quality from electric conversions) are accessible to all.** Today, DER adoption is an individual choice – households and C&I facilities choose whether installing these DERs is economical given their circumstances. High upfront and financing costs may limit access to widespread DER adoption.

- **Access to VPP participation: Reduce barriers to VPP enrollment so that more households and businesses can take advantage of VPP participation payments.** Homes and C&I facilities that have installed DERs choose to participate in a VPP by enrolling in available programs. Lack of accessible programs and limited knowledge of existing programs can limit participation.[17]

See Appendix A.i. for a comprehensive set of actions that stakeholders can take to expand access to community-wide benefits, DER ownership, and VPP participation.

1.iii. Case studies of expanding access to DER ownership

Public and private sector actors are taking action to reduce barriers to DER adoption and VPP participation, and to spread the benefits of VPP deployment more equitably across participating and non-participating ratepayers. This section, along with detail provided in Appendix A, shares how two utilities built VPP programs to expand access to DER ownership for their customers.

15 Energy burden is defined as the percentage of household income that goes toward energy costs.

16 According to RMI's Power Shift report, VPPs could avoid 12 million to 28 million tons of carbon dioxide emissions nationwide by 2035, or 2% to 4% of projected U.S. power sector emissions in 2035.

17 Additional detail on simplifying enrollment can be found in *Chapter 2: Simplifying VPP enrollment.*

Case Study: Roanoke Cooperative, NC

Roanoke Cooperative *uses an inclusive utility investment to reduce upfront cost and financing barriers to adopting water heater control switches and smart thermostats.*

- **Roanoke Cooperative (RC)** launched the Upgrade to $ave program in 2016 to reduce energy bills for the fourth lowest income Congressional district in the U.S.
- The Board of Directors targeted upgrading 1000 homes with energy efficiency and demand response measures. They approved use of the Pay As You Save® (PAYS®) system, an inclusive utility investment model, for the design of the utility program and tariff.[18,lviii,lix]
- RC paid upfront for all cost-effective energy upgrades at a member's residence and recovered its costs through a fixed, monthly cost recovery charge that was lower than the estimated savings from the upgrades on an annual basis.[lx,19]
- To enroll customers, RC assessed the energy savings potential of the building rather than the owner's income or creditworthiness, allowing all members to access low-cost financing options.
- Participating members reduced electricity usage by ~20% because of upgrades and the utility realized peak demand savings of ~20% during summer and winter peaks.
- Including the cost of capital and program operation costs, the utility sees $2M+ NPV over the lifetime of the upgrades.

Detailed case study provided in Appendix A.iii.

Case Study: San Diego Community Power, CA

San Diego Community Power *leverages upfront, stackable incentives to provide the opportunity for no-cost solar and batteries to qualified priority populations.*

- **San Diego Community Power (Community Power)** launched the Solar Battery Savings program in 2024.
- The program was designed to benefit all customers through upfront incentives to lower the initial cost of home solar and battery storage resources.
- Community Power worked with state and local programs to ensure their incentives could stack with other programs such as California's DAC-SASH and SGIP[20,lxi,lxii] programs and the City of San Diego's Solar Equity program to allow priority populations in particular to cover the entire cost of solar and storage resources through available incentives.

Detailed case study provided in Appendix A.iii.

See Appendix A for 13 case studies that are expanding DER adoption with multifaceted benefits (Appendix A.ii. and A.iii.), 5 additional resources (Appendix A.iv.) and 18 supportive DOE programs (Appendix A.v.).

18 PAYS Essential Elements and Minimum Program Requirements provides additional information on the utility program requirements for a PAYS program and PAYS model tariff shares the tariff design.

19 The program's annual cost recovery is set at less than the estimated savings from the upgrades to ensure immediate reductions in energy costs, and much larger cost reductions once the utility recovers its costs and ends the on-bill charge.

20 DAC-SASH is the Disadvantaged Communities – Single-Family Solar Homes program developed by the California Public Utilities Commission (CPUC) and administrated by GRID Alternatives. This state program provides $8.5 million in incentives annually to help homeowners in disadvantaged communities go solar. SGIP is the Self-Generation Incentive Program developed by the California Public Utilities Commission to provide rebates for qualifying distributed energy systems on the customer's side of the utility meter, including advanced energy storage systems, wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, and fuel cells.

Chapter Two: Simplifying VPP enrollment

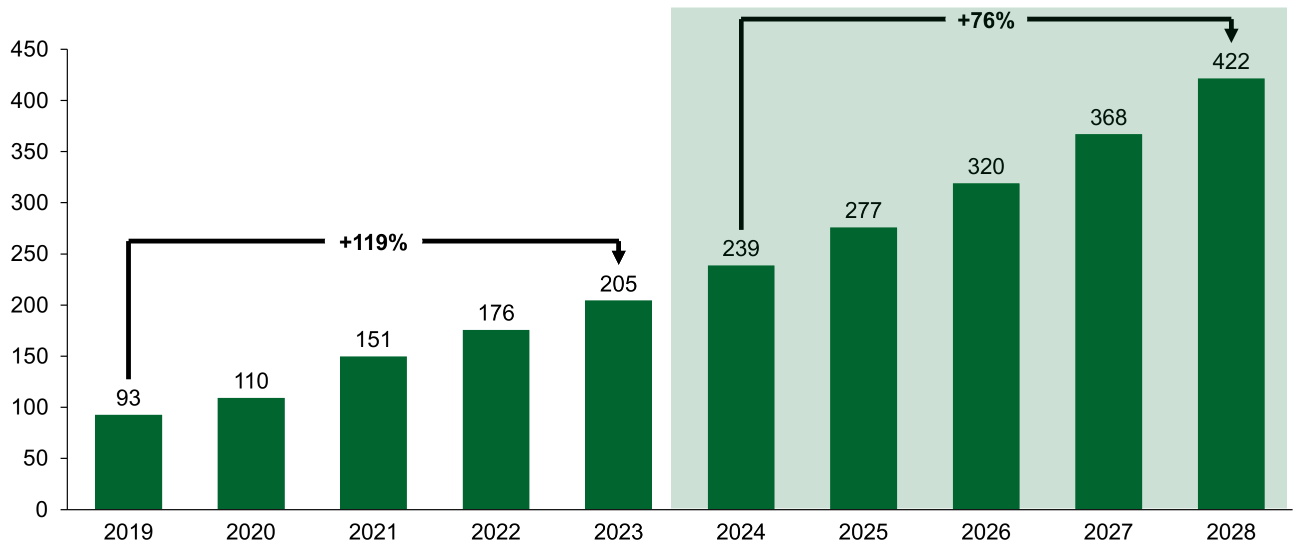
Key takeaways

- VPP deployment can be fast; VPPs can be built and scaled as quickly as customers enroll their devices.
- In addition to the 30 GW of VPP capacity already enrolled today, enrolling 30-50% of the 150-200 GW of *new dispatchable* DER capacity that is projected to be added to the grid between now and 2030 would result in 80-160 GW of VPP capacity nationally.
- Utilities, aggregators, and other industry partners are taking no-regrets (high-impact, low-effort) actions today to improve enrollment, such as communicating concise messaging about program benefits, offering ongoing participation payments, and offering the flexibility to opt out of events.
- These same entities are implementing additional high-impact actions (high-impact, high-effort), but these solutions may require time, effort, and investment to deliver value. For example, automatic enrollment at the point of DER purchase is not widespread today but has been proven to achieve high participation rates without attrition or consumer complaints.

2.i. DER forecasted capacity growth

Across the U.S., DER capacity doubled over the last five years and is expected to nearly double again in the next five years, growing by 217 GW across DER types.

Total DER capacity installed (historical and forecasted), GW

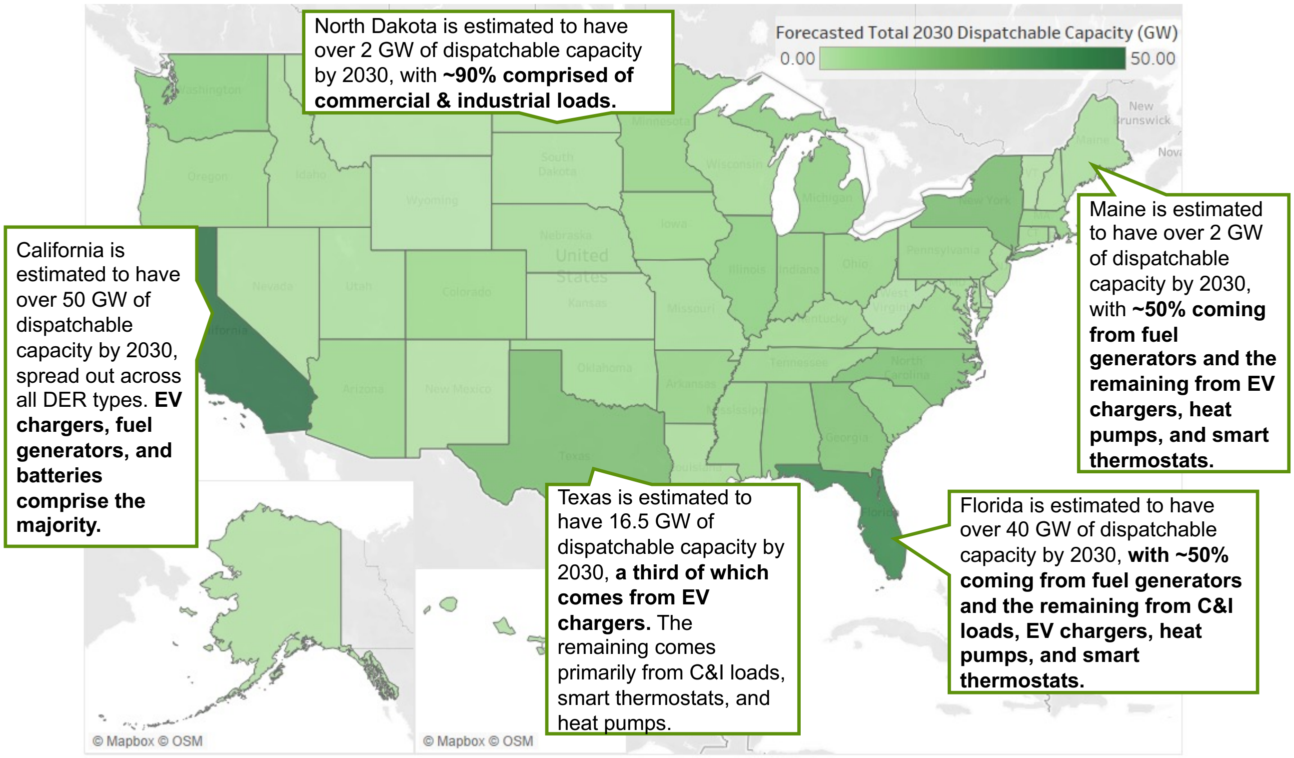


Note: DERs included in capacity projections are smart thermostats, heat pumps, diesel generators, natural gas generators, non-residential solar and storage, residential solar and storage, building automation systems (commercial & industrial loads), and passenger and commercial EV charging.[lxiii]

Source: Wood Mackenzie 2024 US DER Outlook

DER capacity is expected to grow in every state across the U.S., though the magnitude of growth and the types of DERs that come online will vary.

2030 total dispatchable capacity, GW



Note: 2030 total dispatchable capacity is estimated by taking a proportion of total 2030 capacity and applying simplifying assumptions on the proportion that is dispatchable. For solar, batteries, heat pumps, smart thermostats and water heaters, Ohm Analytics estimated 2030 total capacity by state[lxiv]. For EVs and EV charging, NREL's base scenario estimated 2030 total capacity by state.[lxv] For commercial & industrial loads (or building automation systems) and distributed fuel generation, national level estimates from Wood Mackenzie's US DER Market Report[lxvi] were extrapolated to 2030 and allocated to states based on 2022 metering data from EIA.

Source: Ohm Analytics State-Level Residential DER Capacity Forecast, Wood Mackenzie 2024 US DER Market Report, National Renewable Energy Lab The 2030 National Charging Network Report, EIA 2022 Meter Data

Without enrolling available DERs into VPPs, their rapid adoption could strain existing, aging distribution systems that are already near maximum capacity during peak events. Integrating these resources into system planning via VPPs can effectively manage impacts to the distribution system while unlocking additional reliability, affordability, and resilience value for ratepayers (e.g., deferred system upgrades, backup power during emergencies, maximizing use of renewables).

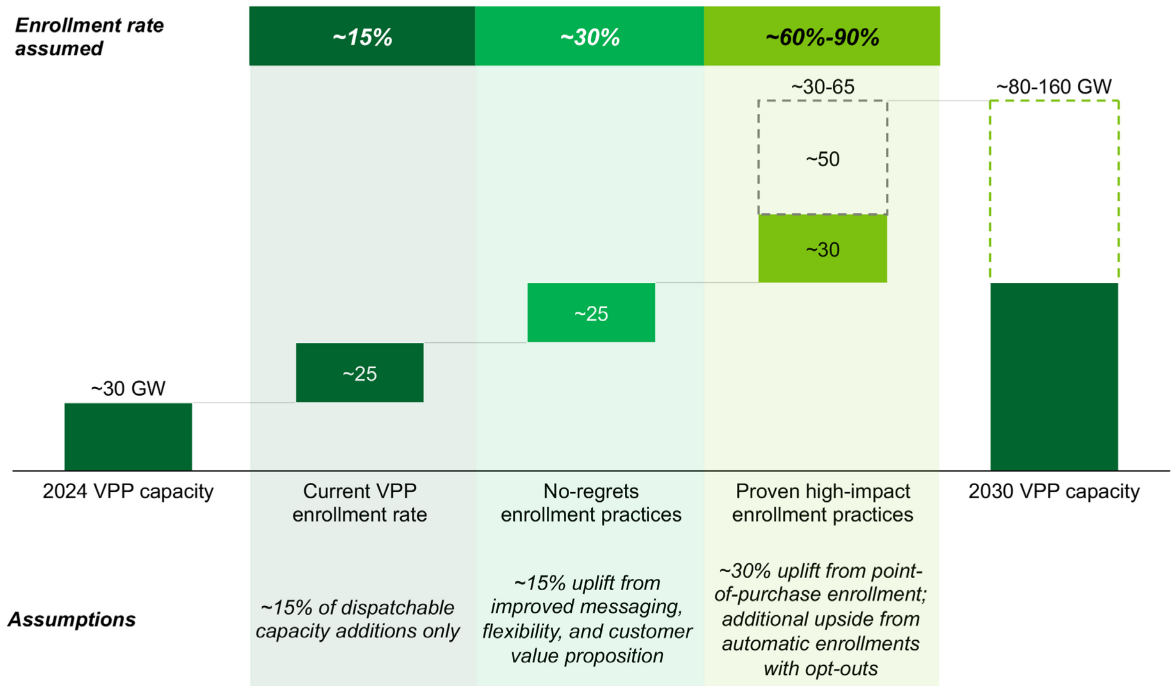
Deploying 80-160 GW of VPP capacity would require enrolling just 30-50% of the dispatchable DER capacity expected to be added to the grid between 2024-2030 – an enrollment rate that is in line with industry estimates for successful VPP programs today.[21] This means 10-20% of peak demand could be served by VPPs in a scenario with baseline forecasts of DER adoption and demonstrated best-in-class VPP enrollment rates.[22] This holds true at the state-level. For example, **Indiana's** state-level peak load for 2030 is estimated to be 19.9 GW and its resource needs are estimated to be 8.5 GW of new generation.[lxvii] Meanwhile, available dispatchable DER capacity is estimated at nearly 8 GW by 2030. Establishing VPP programs and enrolling 25% of total DER capacity in a VPP could meet 10% of peak load by 2030.

21 In Xcel Energy's Northern States Power service territory, over 50% of all eligible residential customers are voluntarily enrolled in some form of air-conditioning load control, with plans for future growth. Otter Tail Power, an investor-owned utility in Minnesota, can reduce its system peak demand by 15% through a portfolio of demand response programs, which are used regularly.

22 See section 4.ii. ('Simplify VPP enrollment') in the 2023 VPP Liftoff Report for detail on the challenges and potential solutions for this imperative (pages 41-43).

Utilities, aggregators, regulators, and policymakers can prioritize no-regrets and high-impact actions to encourage customers to enroll DERs and participate in the clean energy transition.

Total VPP capacity in various enrollment scenarios, GW



Note: 30 GW of VPP capacity today estimated from 33 GW of VPP capacity in North America based on Wood Mackenzie North America VPP Market Report (majority considered to be in the U.S.).[lxviii] Continued current state assumes ~15% of DER capacity additions are enrolled in VPPs, a relatively conservative estimate. Implementing no-regrets levers assumes ~30% of DER capacity additions are enrolled in VPPs, in line with programs today. Implementing high-impact actions assumes ~60% of DER capacity dispatchable additions are enrolled in VPPs, in line with analyses that calculate enrollment potential from point-of-purchase enrollment[23,lxix], with additional upside from automatic enrollments with opt-outs (up to ~90% of DER capacity additions could be enrolled). Analysis shown above only considers capacity potential from enrolling new DERs procured between 2024 and 2030. Enrolling DERs that are already on the grid as of the end of 2024 would be considered upside.

Source: DOE analysis

2.ii. Case studies of simplifying enrollment

Utilities, aggregators, and other industry partners are taking no-regrets actions today to improve enrollment processes with minimal effort. These entities are also implementing high-impact solutions[24], but these levers may require time, effort, and investment to deliver value.[lxx]

No-regrets actions

Low-cost actions that utilities and aggregators can easily implement to improve enrollment. Examples include clear communication of financial benefits, offering a compelling value proposition, and flexibility to opt out of events.

High-impact actions

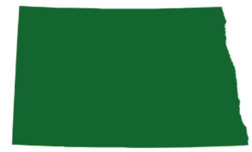
Actions that can take VPP enrollment to the next level, but may require additional time, effort, and investment to implement. Examples include enrollment at point-of-purchase and automatic enrollment with opt-out.

23 Uplight, a flexibility management platform, [found that over 60% of eligible customers purchasing a smart thermostat] through their marketplace enrolled in demand response programs when offered at point of sale.

24 Lawrence Berkeley National Lab and Brattle Group conducted a study working with industry partners to determine the level of effort and the level of impact for 30 enrollment levers. No-regrets actions in this report are defined as levers that were deemed "high-impact" and "low-effort." in that analysis. High-impact solutions are defined as levers that were deemed "high-impact" and "high-effort" in that analysis. See the [Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment] for additional detail on 30 strategies to increase VPP enrollment.

Case Study: Minnkota Power Cooperative, ND *(No-regrets action)*

Minnkota Power Cooperative *enrolled 40% of customer base by communicating financial benefits of enrollment in simple and concise terms.*



- **Minnkota Power Cooperative's** [demand response program] has enrolled 55,000 customers (40% of customers) and can serve 350 MW, 35% of winter peak load,[lxxi] through the program.[lxxii]
- Minnkota provides clear financial benefits for enrollment and participation – upfront incentives to purchase the DERs and customer eligibility for the off-peak program rate, which is roughly half the standard rate, to enroll in the program.[lxxiii]
- During peak events, Minnkota is able to temporarily control DERs including heat pumps, water heaters, EV chargers, and commercial & industrial loads.
- Minnkota also worked to cultivate widespread buy-in from member distribution co-operatives to message the enrollment benefits, providing customers a uniform messaging approach.[lxxiv,lxxv]

Case Study: Arizona Public Service, AZ *(High-impact action)*

Arizona Public Service *Cool Rewards enrolled 97,500+ thermostats by establishing an online marketplace that offers pre-enrollment at point of purchase.*

- **Arizona Public Service (APS)** launched **Cool Rewards**, a smart thermostat program, in 2018 after the Arizona Corporation Commission authorized demand response and load management programs for the utility.
- As of November 2024, the Cool Rewards program has enrolled over 97,500 connected thermostats with the ability to shed over 160 MW of load during peak demand events from both residential and small to medium-sized business customers.
- APS established a smart thermostat marketplace on their website where all customers could get an instant $30 rebate at checkout.[lxxvi]
- APS allowed customers to receive an additional $85 off upfront by pre-enrolling into the Cool Rewards program after providing basic information (e.g., name and address).
- Embedding pre-enrollment into the point-of-sale process reduces marketing and recruiting costs for the program. As of the end of October 2024, 9,290 Cool Rewards pre-enrollments were processed through APS marketplace, which was built in partnership with **Enervee**.[lxxvii]

Detailed case study provided in Appendix B.ii.

See Appendix B for 9 case studies that are simplifying VPP enrollment (Appendix B.i. and B.ii.), 6 additional resources (Appendix B.iii.) and 2 supportive DOE programs (Appendix B.iv.).

Chapter Three: Increasing standardization in VPP operations

Key takeaways

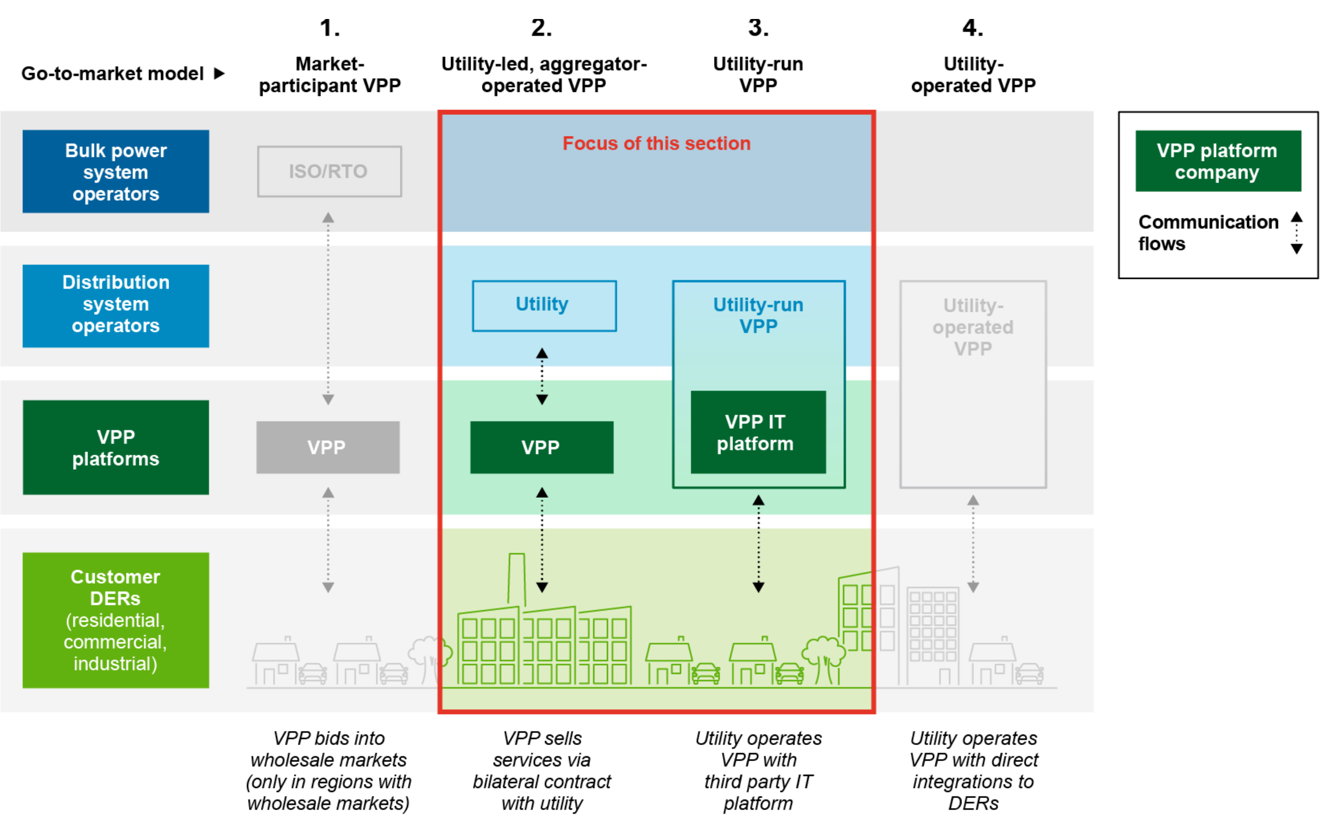
- Increased standardization can reduce the complexity and cost of deploying VPPs. New efforts are underway within and outside of DOE to align on industry standards for utility-aggregator interfaces, aggregator-DER interfaces, cybersecurity, and other aspects of VPP operations.
- Even in the absence of standards, many utilities today use basic VPP configurations to reduce system-level peak demand. This kind of VPP can be deployed at scale within six months with less than $1M in upfront investment and can create a foundation for more sophisticated VPP models that deliver a broader range of benefits.
- More sophisticated VPPs can deliver distribution grid services and unlock additional value streams (e.g., deferral of distribution system upgrades). These solutions may require the installation of additional hardware and software that provide (1) higher-resolution visibility into distribution grid conditions through sensors and improved data analytics and (2) more frequent and localized dispatch of DERs.

3.i. Variation in utility-led VPP operations

A lack of technology interoperability and other operational standards across utilities, state and tribal governments, and regional markets has made it difficult to repeat and scale proven VPP models nationally, but this has not prevented a proliferation of successful, albeit bespoke, VPP deployments. VPP platform companies and related service providers have had to customize individual VPP deployments to adapt to the protocols and systems of specific utilities, align to the program budget structures of specific state utility regulators, and abide by the rules of specific wholesale markets, minimizing positive economies of scale nationally.

Although the flexibility and adaptability of VPPs as a technology category is part of the value proposition, their variability has created the false impression that individual VPPs are inherently complex. In fact, an individual VPP can be simple for utilities and grid operators to deploy and operate (*see ConnectedSolutions case study in Section 3.iv.)*. This is particularly true when the orchestration of the DER aggregation is managed by third party aggregators and delivered to utilities as a single resource without integrating the aggregation platform into utility systems. The complexity arises when looking *across* VPPs at the many different ways operators structure and send data, define grid services, and design software interfaces in the absence of standardized approaches.

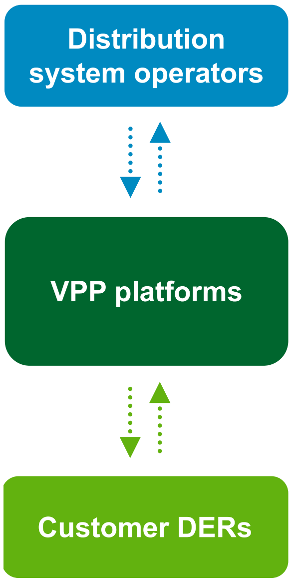
VPP market participation models[25]



3.ii. Standardization efforts recently launched or expanded

In the past year, DOE and other industry actors have launched or expanded efforts to standardize critical areas of VPP operations to reduce complexity and cost of implementation and increase reliability of performance.[26]

Recent efforts to increase standardization in VPP operations



	Focus area of recent standardization efforts	*Example initiatives (not exhaustive)*
1	**VPP platform to utility communication interface**	• FlexIT (EPRI) • TSO-DSO-DER Aggregator operational platform (DOE)
2	**Grid services definitions**	• Distribution System Transformation resources (DOE)
3	**Aggregator service contracts**	• Standardized services contract (NAESB, DOE)
4	**VPP platform to DER communication interface**	• Mercury Consortium (Kraken, industry) • Consortium for Energy Efficiency (industry-led)
5	**Meter data format and access rules**	• Green Button Standard (industry-led)
6	**VPP resource definition**	• Guide for VPP specifications (IEEE Working Group 2030.14, *forthcoming*)
7	**Shared DER registry**	• DER registry model (Collaborative Utility Solutions, DOE)
8	**Cybersecurity for DERs**	• DER Cybersecurity Best Practices (DOE) • UL 2941 cybersecurity certification standard for DERs (DOE, industry)

25 For a simple explanation of U.S. electricity market structures that influence VPP market participation models, see the 2023 VPP Liftoff Report.

26 See section 4.iii. ('Increase standardization in VPP operations') in the 2023 VPP Liftoff Report for detail on the challenges and potential solutions for this imperative (pages 43-47).

Successfully developing standards that are universally applicable will require diverse expert input from technology manufacturers, software developers, service providers, load serving entities, and other practitioners. Industry groups and community organizations can also play an important role by convening stakeholders to contribute to these efforts, and by packaging insights for policymakers and regulators to incorporate into their decision-making processes.

Area of operations	Description	Example standardization initiatives
VPP platform to utility communication interface	VPP platform providers must be able to send and receive information to and from a utility using an interface and data language compatible with utility IT systems, which vary from one utility to the next.	• **EPRI** launched the FlexIT initiative to deliver technical specifications for providing DER discovery and visibility, and to establish standards for the core utility-to-VPP/aggregator interactions involved in the provision of T&D grid services.[27,lxxviii] In addition to writing a standard and accompanying guidance, the initiative aims to build a mock utility and mock aggregator interface with reference code to test for interoperability.[lxxix] • The **DOE Office of Electricity** is developing guidelines for a TSO-DSO-DER Aggregator operational platform as well as corresponding coordination requirements.
Grid services definitions	Grid services definitions make up the taxonomy and functional criteria of grid services procured for safe and reliable bulk power system, distribution system, and grid edge services. Today, different grid operators set their own definitions.	• **DOE's Office of Electricity** has published working definitions of grid services for bulk power, distribution, and grid edge services as part of its library of Distribution System Transformation resources.
Aggregator service contracts	The contract governing the delivery of grid services from a third-party aggregator for a utility includes terms and conditions around customer engagement plans, dispatch schedules, dispatch capacity limits, performance evaluation methods, settlement processes, and more. Given the rapidly evolving market, there has been little convergence to date on the structure of these contracts.	• The **North American Energy Standards Board (NAESB)**, in partnership with **DOE's Office of Electricity**, is developing a standardized services contract for VPP providers for distribution market interactions.[lxxx]

27 This initiative builds on past efforts such as the IEEE 2030.11 Guide for Distributed Energy Resources Management Systems (DERMS) Functional Specification, which DOE has supported.

VPP platform to DER communication interface	VPP platform providers' IT systems connect to and communicate with DERs through application programming interfaces (APIs) that must be compatible with the specific manufacturer-installed software.[28] Without interoperability standards (i.e., standardized software interfaces), each VPP platform must write brand-specific APIs and maintain them as manufacturers update their software.	- The Mercury Consortium, led by VPP platform **Kraken** and its partners, launched in 2024 to increase adoption of existing standards for flexible demand devices[29] and address gaps in testing and certification[30] of those standards as they are built into devices. Such standards may include OpenADR, CTA-2045, IEEE 2030.5, and MATTER. - The Consortium for Energy Efficiency, an organization of utilities administering ratepayer-funded efficiency programs across North America, has adopted new specifications for heating, ventilation, and cooling (HVAC)[lxxxi] and water heating[lxxxii] equipment to require that equipment meet the relevant industry standard for "communication, infrastructure, and system functionality as these relate to the implementation of energy management strategies" starting in 2026.[31,lxxxiii]
Meter data format and access rules	The Green Button[32,lxxxiv] initiative is an industry-led effort to provide utility customers with easy and secure access to their energy usage information in a consumer-friendly and computer-friendly format.[lxxxv] Since its launch in 2012, utility implementation of the data and access standards has been voluntary, and many non-utility grid service providers point to insufficient implementation as a major obstacle to sharing grid data that could accelerate grid modernization.	- Additional utilities (**Consumers Energy** in Michigan[lxxxvi], **Louisville Gas & Electric** in Kentucky[lxxxvii], and **Entergy** in Texas[lxxxviii]) representing over two million customers have adopted the Green Button standard since 2023.

28 Problems can arise when VPP platforms do not properly integrate with devices. For example, in a practice called "screen scraping," an aggregator might write code that integrates with a consumer app (e.g., the EV brand app) rather than the device software itself (e.g., the EV telematics). This practice could violate terms of the device software, lead to bugs when the consumer app is updated and the code is not, and overall does not offer high-fidelity information exchange required for grid operations.

29 IEEE 1547 is a common communication standard for generation-capable devices. Complying with this standard requires following specified rules (e.g., IEEE 2030.5, SunSpec Modbus) for how DER capabilities are set and monitored, such as voltage regulation settings, power factor settings, and power export limits. These rules specify a structure for data to enable interoperability among system components made by different manufacturers. In contrast, flexible demand devices are generally less standardized in their communication protocols and data formats.

30 Testing and certification of products and their software are important to validate that standards are properly incorporated. Beyond testing and certification, incentives (carrots) or enforcement and penalties (sticks) would help increase standards adoption.

31 This action also means that the federalFederal tax credit for this equipment will only be available to DR-ready equipment. In 2023 alone, over 850,000 households claimed this credit for electric HVAC or water heating equipment.

32 Green Button is based on the Energy Services Provider Interface (ESPI) data standard released by the North American Energy Standards Board (NAESB) in the fall of 2011. The data standards development process was facilitated by the National Institute of Standards and Technology (NIST). The ESPI standard consists of two components: 1) a common XML format for energy usage information and 2) a data exchange protocol which allows for the automatic transfer of data from a utility to a third party based on customer authorization.

VPP resource definition	The term 'Virtual Power Plant' commonly refers to a category of resources rather than one narrowly defined asset. Even so, the term is interpreted differently across different stakeholders today.	- **IEEE Working Group 2030.14** is developing a guide for VPP functional specification for alternate and multi-source generation.
Shared DER registry	Recruiting VPP participants can be costly for a utility or aggregator. A DER registry would serve as an opt-in database of existing DERs in a given jurisdiction (the registry could be implemented state-wide or market-wide, where applicable) that logs information on the DER location, type, and functional ability to provide grid services. A primary goal of the registry is to accelerate the identification of DERs and enrollment into VPPs.	- **Collaborative Utility Solutions**, with support from **DOE**, developed and launched a **functional DER registry model**[lxxxix] that can be adopted and implemented by states and tribes and shared by their utilities so that each jurisdiction does not need to build their own independently. This model registry uses a common information model (CIM) for all users that covers critical inputs for the integration of DERs into grid operations.
Cybersecurity for DERs	Most DERs installed in homes and businesses today are connected to communications and control software and networks, and are interconnected with the electric grid. This increase in connection points widens the attack surface that could be exploited by malicious actors. Cybersecurity strategies ranging from data encryption to system governance can be engineered into utility and aggregator systems in many ways to secure grid operations and protect customers.	- **DOE's Office of Cybersecurity, Energy Security, and Emergency Response** is continuing to develop and disseminate cybersecurity "baselines" and **best practices for DERs** and VPPs to safeguard against risk. - **DOE and industry partners** initiated the **UL 2941 cybersecurity certification standard for DERs** in 2023 to map hardware and software security requirements from industry best practices and provide information for industry stakeholders.

Three additional areas of VPP operations that market participants say sorely need more standardization are discussed in the context of FERC Order 2222 implementation in *Chapter 5: Integrating into Wholesale Markets*. They include electricity consumption data access, DER metering and telemetry, and DER aggregation participation models.

See Appendix C for 2 additional resources (Appendix C.iv.) and 17 supportive DOE programs (Appendix C.v.).

3.iii. VPP performance attributes

Not all variation in VPP configurations is counterproductive; new innovations in VPP design and implementation have increased the delivered benefits of VPPs across the country. The "right" configuration of VPP hardware and software will be determined by the desired performance attributes of the VPP, which are a function of the needs and priorities of the utility.

Relatively basic VPPs that deliver bulk system peaking capacity can be launched in a short timeframe (<6 months) with minimal upfront cost (<$1M), while providing high-value peak shaving benefits to ratepayers and the grid. These basic VPPs can build additional capabilities over time and establish a foundation for more sophisticated models in several ways.[33] Grid services, frequency of dispatch, and scale can all increase incrementally if and when needed.[34] Within the utility, operating a basic VPP at scale produces a wealth of historical DER and participant behavior data that can be used to train predictive models of VPP performance; this can help a utility set appropriate incentive payment levels, set event frequency limits to prevent participant attrition, test automatic enrollment effectiveness, and more.
Building the VPP's dispatch 'track record' can also help grid planning teams better understand the value of the resource and model the VPP resource into future generation, transmission, and distribution investment scenarios.[35] Outside of the utility, customers become familiar with VPP participation options and participants grow accustomed to potential changes in behavior (if any). Regulators also gain familiarity and comfort with VPPs as a reliable tool to manage the grid more affordably and reliably.

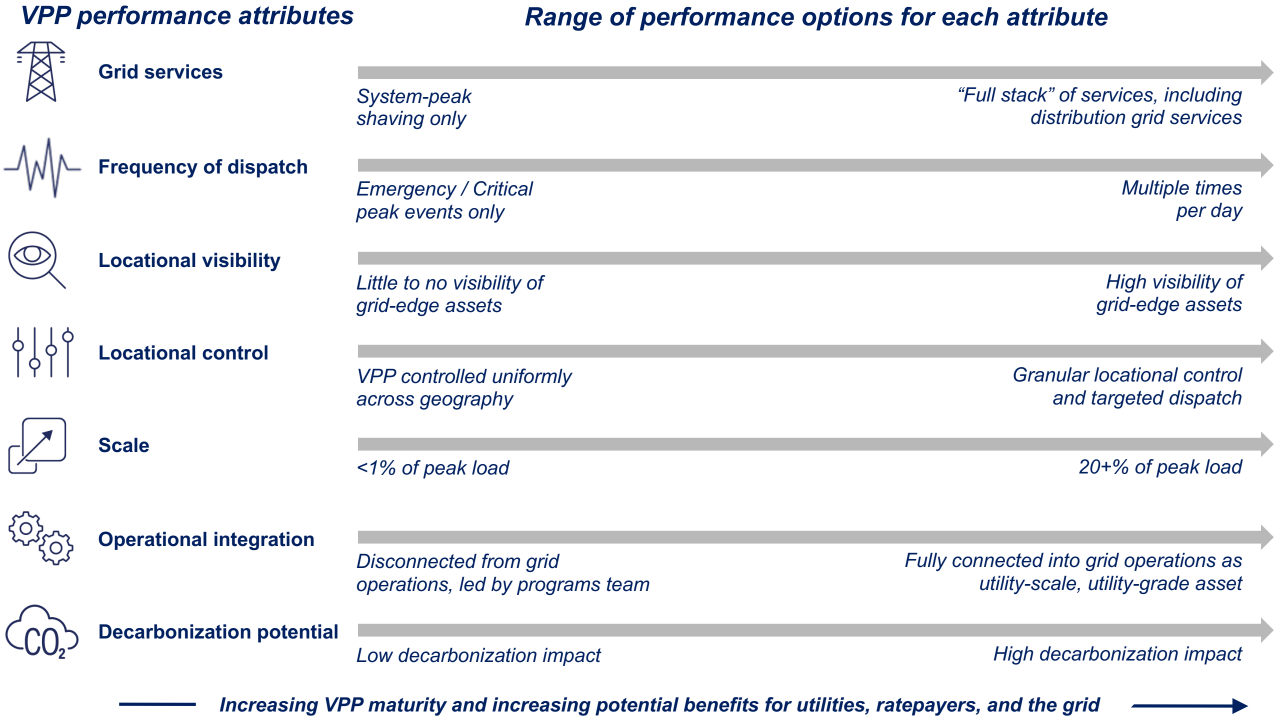
The progression from basic to more sophisticated utility-led VPP configurations can be assessed along at least seven performance attributes. A given VPP may not necessarily advance along all attributes in unison; rather, its specific performance requirements will be dictated by utility needs and priorities.

33 Capex-light, basic VPP-related investment may be low-risk for utilities because they avoid locking into one technology for long periods of time. Utilities can carefully analyze potential investments in durable equipment, and in particular metering infrastructure. While some VPPs rely on meter data for performance measurement, others operate independently of advanced meters by integrating DERMS software directly into DER software-based controls (e.g., smart thermostats, batteries) and collecting data directly from the device for performance measurement and settlement. Any significant investment in advanced metering infrastructure should involve a long-term technology and functionality roadmap that weighs the costs and benefits of different system architectures. This is particularly important in light of recent metering technology advancements that equip meters with new computing and communication capabilities with an associated cost increase from roughly $150-200 per meter to double that price or more.

34 Adding capabilities to existing programs that already have customers enrolled has advantages over adding new and separate programs, particularly in jurisdictions that only allow enrollment in a single program per meter.

35 The need to build a track record of performance data has often been cited as a reason to pilot a VPP before deploying it at scale. This has held back VPP growth when programs stay in the pilot stage without a path to scale in regulatory or utility management plans. This can be prevented by implementing first-time VPPs without an end-date or capacity limit, establishing go/no-go milestones as safeguards against poor performance, continuously monitoring performance indicators, and allowing for ongoing improvements to operational parameters.

VPP performance attributes and corresponding range of performance options



Each of these seven performance attributes is described in more detail below.

Grid services: System peak shaving or shifting is the most basic functionality of a VPP, but DER aggregations can provide additional services such as energy, frequency response, black start, and more[36,xc] with the right mix of DERs and the right underlying software and hardware.

Frequency of dispatch: While some basic VPPs are called only during critical grid events, more sophisticated VPPs can be dispatched more often – potentially multiple times per day – to support normal grid operations.

Locational visibility: For VPPs to go beyond system-level benefits and provide distribution grid benefits, a utility must understand where it faces distribution grid constraints or problems that VPPs might alleviate. This requires heightened situational awareness of conditions on the distribution grid, which is not common among distribution system operators today.[37,xci]

36 For a full list of grid services and definitions, see Bulk Power, Distribution, and Grid Edge Services Definitions from DOE's Office of Electricity.

37 A variety of grid technologies can enhance situational awareness. This includes advanced distribution management systems (ADMS), which are software platforms that integrate numerous utility systems and provide automated management of distribution grid performance. ADMS often collects data from supervisory control and data acquisition (SCADA) systems. Monitoring and management systems for distribution grid assets, up to and including a customer's meter are sometimes referred to as a "*Grid* DERMS" (distributed energy management system). This is distinct from an "***edge*** DERMS," described below. These few examples illustrate the variety of possible enabling technology configurations.

Locational control: Locational control goes hand-in-hand with locational visibility. For a VPP to react to, or prevent, a location-specific distribution grid constraint with services from a local DER aggregation, the VPP requires granular control of DER sub-aggregations within the overall resource. It also requires an understanding of how a DER's physical location – i.e., street address – maps to the topology of the grid, to ensure the right DERs are called upon to drop load (or export energy).[38]

Scale: As VPP capacity (MW or MWh) grows relative to system peak demand, grid operators rely on VPPs for a higher percentage of grid resources (generation supply and T&D capacity). More sophisticated VPPs manage a higher percentage of system peak demand.

Operational integration: The extent to which VPPs are incorporated into the planning process and regular operations of a utility's distribution, transmission, and generation teams varies widely. Historically, many basic VPPs have been managed by customer programs teams with little to no impact to other functional groups within utilities; this limits the potential benefits of the VPP for the broader utility system. In contrast, leading utilities who operate more sophisticated VPPs have incorporated them into integrated planning processes and operations (*discussed further in Chapter 4: Integrating into utility planning & incentives)*. In other words, these utilities consider VPPs in the option set alongside traditional resources when making decisions in capital planning, ratemaking, and maintenance schedules.

Decarbonization potential: Most VPPs dispatch to optimize one variable: costs. They reduce costs by decreasing demand during system peak hours to avoid high energy prices, or decrease local peak to defer a costly equipment upgrade. More sophisticated algorithms also consider the avoidance of greenhouse gas emissions, thereby optimizing around multiple desired outcomes.

As the descriptions above illustrate, most VPP performance attributes relate to *how* technology is used rather than *what* technology components (hardware and software) are used. An important exception may be among utilities who need to make incremental investments to implement technology such as ADMS and related tools to gain situational awareness at the grid edge and enable location-specific distribution grid services from VPPs. These systems create and transmit the data about grid conditions that dictate VPP operations and dispatch.[39]

Utilities that have launched active managed EV charging VPPs are leading examples of utilities investing in the capability to optimize distribution grid conditions. Rather than setting EV charging schedules (or calling events ad hoc) only in response to day-ahead energy prices from wholesale markets, these VPPs are *also* managing charging in response to real-time grid conditions based on data collected from distribution grid equipment.[40] Examples include programs operated by VPP provider **WeaveGrid** with utility partners **Baltimore Gas & Electric**, **Pacific Gas & Electric**, and others, and other programs operated by **EnergyHub** with utility partners such as **Eversource**.[xcii]

38 An "edge DERMS," refers to a software platform that controls or sends signals to equipment behind the customer's meter (i.e., directly to DERs or DER owners). The edge DERMS aggregates independent DERs and orchestrates them to act as a utility-scale resource. While an edge DERMS may know the address of the DER, it must be integrated into the utility's system (i.e., the ADMS or Grid DERMS) to know how the behavior of each DER impacts the distribution system.

39 Managing the enrolled DERs of a VPP to enhance distribution grid operations typically requires automated dispatch of DERs because a given utility may have thousands or tens of thousands of load limits to monitor across its distribution system – more than can be managed manually. Automation based on granular locational conditions often requires tight integration between the utility system and the edge DERMS, which requires investment from the utility.

40 For in-depth explanations and case studies of multi-layered optimization in EV managed charging programs – including optimization for distribution grid congestion and optimization for renewable energy generation—see the State of Managed Charging in 2024 report from the Smart Electric Power Alliance.

3.iv. Case studies of utility-led VPP operations

VPPs can be deployed in less than six months with less than a million dollars of investment to avoid higher costs of traditional assets. Examining and comparing the operations of multiple utility-led VPPs can help illustrate the differences between a relatively basic versus more sophisticated VPP and provide context for areas where increased standardization can streamline implementation. This section, along with detail provided in Appendix C, explains how three real, utility-led VPPs operate to demystify the communication technology that enables a VPP and to compare their relative performance across the seven attributes outlined in the previous section. In doing so, the case studies may help stakeholders pinpoint where increased standardization is most needed (and where it is not).[41]

National Grid's 'ConnectedSolutions' in Massachusetts, Green Mountain Power's 'Energy Storage System' (ESS) Leasing program in Vermont, and Rocky Mountain Power's 'Wattsmart' in Utah each employ different information technology (IT) and operational technology (OT) configurations in their VPPs. Each has proven to be cost-effective and reliable for the utility and customers, and each is growing its capacity as more participants choose to enroll.

Case Study: National Grid, ConnectedSolutions, MA and NY

***National Grid established a multi-device VPP** within 4 months with <$500k upfront investment that now provides up to 250 MW of peak shaving benefits.*

- **National Grid** developed and launched its ConnectedSolutions 'bring-your-own-device' (BYOD) VPP in less than four months to provide low-cost, low-emissions peaking capacity in Massachusetts and New York.[42]
- In this configuration, National Grid contracts with **EnergyHub**, an edge DERMS vendor that integrates multiple DER software systems into one platform. The heterogenous aggregation is controlled as one cohesive, utility-scale resource.
- National Grid sends notices to EnergyHub in advance of peak hours to dispatch demand reductions from the customer-owned DER aggregation that EnergyHub manages on National Grid's behalf.
- National Grid required little change to its internal organizational operations to implement the VPP. System integration is low; a National Grid employee logs into EnergyHub's online portal to send instructions and collect data.

41 While this section focuses on utility-led VPPs, *Chapter 5: Integrating into wholesale markets* focuses on VPPs that sell grid services into wholesale markets and includes discussion of variation across ISO/RTOs.

42 For additional detail on the policy and regulatory context in which ConnectedSolutions was implemented, including the energy and non-energy benefits included in the cost-effectiveness test for the program, see the case study annex (page 66) of NARUC's ADER Resources in 2024: The Fundamentals.

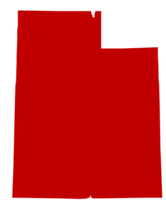
Case Study: Green Mountain Power, Energy Storage System Leasing Program, VT

***Green Mountain Power launched a utility-owned and operated battery VPP** that offers backup power for participants, peaking capacity, emissions reduction, and transmission benefits for the grid, and lower costs for all customers.*

- **Green Mountain Power** fully launched the Energy Storage System (ESS) Leasing program in 2020 to improve system reliability in the face of extreme weather while reducing costs for all customers.[43]
- GMP operates the program with **Tesla** technology. Tesla supplies the battery hardware (Powerwalls) and acts as the software platform that aggregates and orchestrates battery dispatch.
- Tesla uses real-time load data provided by Green Mountain Power via an API to strategically dispatch batteries to shave peaks on the distribution system.

Case Study: Rocky Mountain Power, WattSmart, UT

***Rocky Mountain Power developed a battery VPP** that integrates directly into its grid operations system and enables many grid services.*



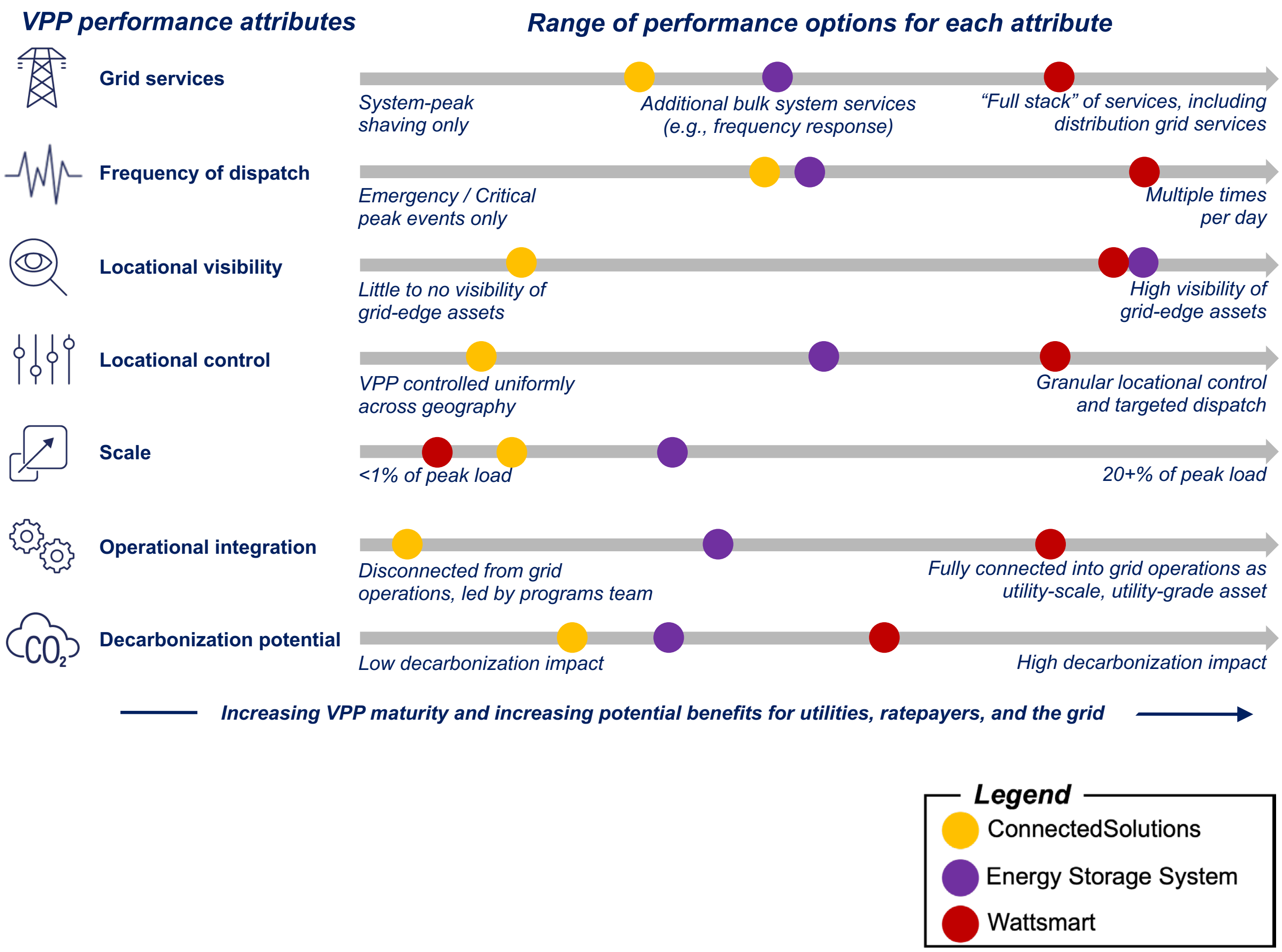
- **Rocky Mountain Power** developed its Wattsmart battery VPP in partnership with **sonnen** to deliver high-value grid services cost-effectively and increase battery adoption among customers.
- RMP creates significant value for the grid by obtaining a "full stack" of valuable grid services from the batteries, paying participants upfront and ongoing performance incentives.
- Unlike VPPs used only during peak hours or peak seasons (summer, winter), RMP may use its batteries 365 days of the year, 24 hours per day.
- RMP's grid operations team directly dispatches the batteries using a distributed battery grid management system (DGBMS) that integrates battery controls directly into the utility's energy management system without any intermediate software layers.
- The network of batteries can respond automatically to grid signals in as little as three seconds (sonnen and Core+ batteries) and no slower than 50 seconds (other brands). RMP personnel can override automated dispatch at any time.
- The Wattsmart VPP is growing rapidly, with a near-term goal of reaching 100 MW by recruiting customers with solar arrays (>80,000 in Utah) and offering battery incentives to motivate customers to 'firm' their renewable power.

See Appendix C for detailed case studies that include program overviews, communication protocols & operations, and IT and OT components for each of the three VPPs referenced in this section.

43 For additional detail on the policy and regulatory context in which GMP implemented its VPP, including the monetized and non-monetized benefits of the program, see the case study annex (page 63) of NARUC's ADER Resources in 2024: The Fundamentals.

As the ConnectedSolutions example demonstrates, VPPs can be quick and extremely cost-effective to implement for system-level peak shaving benefits.[44,xciii] ESS and Wattsmart demonstrate that VPPs can deliver a wider range of grid services with incremental IT and OT capabilities that integrate VPP operations into utility systems. Each of the examples is designed to meet the needs of the specific utility and its customers. Below, the examples are compared along the seven performance attributes.

VPP performance for three utility-led VPPs



44 LUMA's Customer Battery Energy Sharing program in Puerto Rico is another example of a VPP providing peaking capacity (over 10 MW) without incremental investments in grid modernization; LUMA operates its VPP without a DERMS and without advanced metering infrastructure.

Chapter Four: Integrating into utility planning & incentives

Key takeaways

- Across the U.S., VPP deployment has been highest in the states with supportive state regulatory and/or policy actions.
- Many state utility regulators – public utilities commissions (PUCs) and public service commissions (PSCs) – have opened regulatory proceedings within the last 18 months to advance VPP adoption. Examples include requiring longer-term distribution grid planning that incorporates consideration of VPPs and establishing or revising compensation mechanisms to better align utility financial incentives to positive grid and customer outcomes.
- Legislative changes to utility regulations or policy are not necessary for investor-owned utilities to deploy VPPs today, but can accelerate deployment by establishing a direction and removing ambiguity about VPP goals and other program parameters (e.g., types of DERs, desired grid services). Examples include Colorado and Maryland legislative actions.
- Regulators and policymakers approaching VPPs today can draw from the menu of 22 policy actions underway across the U.S. to inform program design and integrate VPPs into utility planning and incentives.

Note: This chapter discusses state regulatory and policy actions that are most relevant for investor-owned utilities (IOUs) regulated by state PUCs/PSCs. Governing bodies of other utilities (e.g., member boards of co-ops, city councils overseeing public power, tribal utility authorities) can also look to these levers for consideration, but the historical financial disincentives impacting IOUs may be less relevant to nonprofit cooperatives and municipally run utilities.

4.i. Utility financial incentives and VPP deployment

In the era of flat electricity demand over the last two decades, VPP deployment by investor-owned utilities (IOUs) was in part stifled by a lack of financial incentives because it meant lower utility profits. Under conventional regulatory models, IOUs can earn an authorized return on equity (typically 9-11% annually) on capital investments; thus, IOUs deploying a low-capex VPP to add system capacity instead of a traditional capex-heavy investment (e.g., a peaker plant) would have realized lower profits.[45]

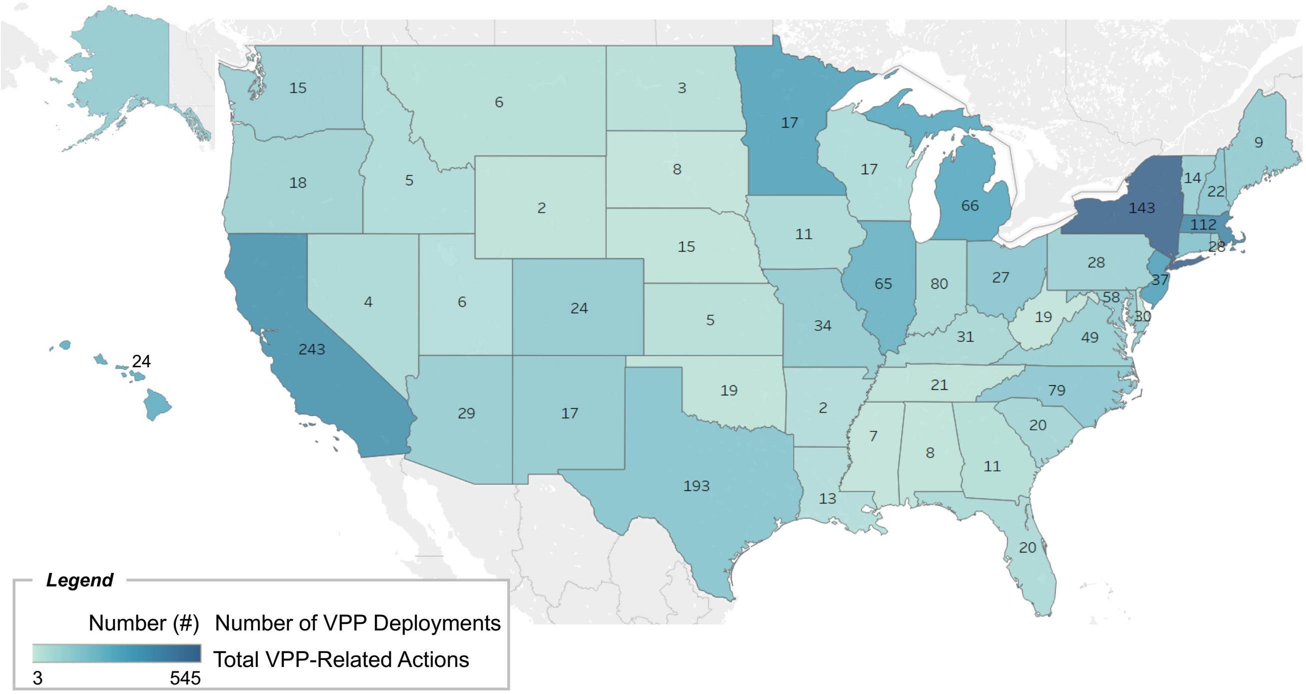
Today, rising electricity demand and the need to replace aging grid infrastructure means many utilities have rapidly growing capital needs. In this context, IOUs can deploy VPPs to help meet system needs and interconnect more load,[46,xciv,xcv] while creating room in their budgets for necessary capital-intensive investments elsewhere (e.g., transmission expansion, new bulk power generation assets). Additionally, state regulators and policymakers are applying pressure to limit capital expenditure and increasingly pushing back on utility investment plans to ensure any increase in customer bills is fully warranted. For example, in December 2023, the **Illinois Commerce Commission** rejected **Ameren Illinois** and **Commonwealth Edison**'s multi-year integrated grid plans over concerns that the utilities did not adequately "consider affordability and cost-effectiveness [criteria] so that customers are not unfairly asked to shoulder undue costs."[xcvi]

45 See page 48 of the 2023 VPP Liftoff report for additional detail on utility compensation structures.

46 For example, since 2017, Arizona Public Service (APS) has been developing demand response and load management programs (with approval from the Arizona PUC) to aggregate DERs into VPP programs, helping manage growing load (as discussed in APS' 2019 IRP Draft). In Minnesota, Northern States Power Company (doing business as Xcel Energy) introduced the concept of distributed capacity procurement (DCP) in comments for an IRP filing (Docket No. E002/RP-24-67) and said the program could provide 400 – 1,000 MW of capacity; actual plans with specifics would be included in the future IRP.

While IOUs can start implementing VPPs without any regulatory or policy changes, supportive regulatory and policy action is accelerating VPP deployment. Across the U.S., localities where state regulators or policymakers have taken VPP-supportive actions have seen the highest number of total VPP deployments to date.

Number of VPP deployments (as of July 2024) vs. state policy/regulatory VPP-related actions (2020-Q3 2024), count



Note: Number of VPP deployments based on Wood Mackenzie data as of July 2024.[xcvii] Wood Mackenzie defines a VPP deployment as: "The association of a vendor aggregation and a DER program. Aggregation is broadly defined to consist of DERs or loads directly under vendor management, or under the management of a downstream device partner. Example: If three vendors partner on a VPP that is monetized through two programs, there will be six deployments recognized." State regulatory and policy actions based on North Carolina Clean Energy Technology Center and includes data from Q1 2020 – Q3 2024.[xcviii] VPP-related state policy/regulatory actions include all types of actions tracked by DSIRE Insight (studies, policy, incentives, deployment, rates) that include the technology tag: demand response, grid modernization, smart grid, storage, AMI, DER, distribution system planning, data access, VPPs.
Source: Wood Mackenzie 2024 NA VPP Market Report, North Carolina Clean Energy Technology Center Policy & Regulatory Actions

State regulators and policymakers play a critical role in enabling a statewide VPP approach to support easier scale up across utility jurisdictions. While several utilities have pursued VPP deployments before any policy or regulatory action, state policy and regulatory efforts have been important to supporting broader adoption by integrating VPPs into standard utility processes (including planning and cost recovery) and aligning utility and ratepayer incentives. As discussed in the 2023 VPP Liftoff Report, increased VPP standardization will accelerate VPP integration in utility planning and incentives.[47]

47 See page 35 of the 2023 VPP Liftoff Report for additional discussion on the imperatives.

4.ii. Supportive regulator actions for integration into utility planning and incentives

All state regulators have the authority to pursue actions that could support VPP deployment.[48] As part of their mandate to ensure affordable and reliable electricity service, PUC/PSCs can proactively direct utilities to fairly consider VPPs alongside ongoing conventional capital investments (e.g., bulk power generation, transmission, distribution) to meet grid needs. In many states, PUCs' legacy organizational models, limited staff capacity, and reactive cultures have resulted in limited proactive engagement with utilities before they submit investment plans (e.g., providing proactive guidance on considering VPPs).[xcix] This is starting to change as mounting load growth, affordability, and reliability pressures on the grid are motivating several state PUCs to proactively provide direction and establish programs that can influence IOU investments, including VPP deployments.

Supportive regulator actions for VPP integration into utility planning and incentives *(not exhaustive)*

Utility cost recovery	System planning	DER deployment	DER aggregation	VPP operations
Establishing utility cost recovery methods for VPP-related investments	Improving grid planning processes to better integrate VPPs as a solution	Implementing or revising programs to increase DER deployments, which enhance VPP potential	Developing DER aggregation models and deployment requirements to enable VPPs	Supporting VPP operations to proactively address common VPP deployment barriers
• Massachusetts • Michigan • Vermont	• Georgia • Massachusetts • Minnesota	• Colorado • Michigan • New York • South Carolina	• California • Colorado • Texas	• Connecticut • Massachusetts • New York • Rhode Island

See Appendix D.i. for a menu of additional regulatory and policy options that regulators and policymakers can consider alongside case studies of how those options have been implemented to date.

Example types of actions that PUCs have pursued recently to drive uptake of VPPs include:

1. **Utility cost recovery: Establishing utility cost recovery methods for VPP-related investments.** PUCs are implementing performance incentive mechanisms (PIMs)[49,c] and clarifying what types of VPP-related investments are eligible for cost recovery (e.g., including DERs in utility rate base,[50,ci] capitalizing software costs).

2. **System planning: Improving grid planning processes (e.g. integrated distribution system planning) to incorporate VPPs as a solution.** PUCs can implement integrated distribution system planning to require objective-driven planning (e.g., grid reliability improvements, customer empowerment), planning over long-term time horizons (e.g., 10+ years), and consideration of comprehensive solutions to address grid needs (e.g., DERs, VPPs).[51,cii] Today, 21 states and the District of Columbia require utilities to file integrated distribution system plans[ciii];

48 State regulators include public utility and public service commissions (PUC/PSCs) that regulate most investor-owned utility (IOU) planning, operations, and retail compensation as relates to VPP deployment and the distribution system. PUC/PSCs review and approve IOU capital investment plans and have authority over determining IOU capital return rates, customer rate designs, and other distribution system plans. See VPP Liftoff report page 20 of the 2023 VPP Liftoff Report for additional info on state regulator roles and responsibilities.

49 Performance incentive mechanisms (PIMs) is a type of performance-based regulation (PBR). PBR is a regulatory model that financially rewards utilities for positive ratepayer outcomes, rather than returns on capital expenditures. See NARUC's PBR Overview to learn more. See RMI's PIM Database for a longer suite of examples of PIMs that PUCs and utilities have implemented.

50 Proposals for utilities to own behind-the-meter devices, such as batteries or generators, have drawn criticism from some industry participants who say that although such an approach may lead to faster scale-up of VPPs, it may lead to higher electricity prices for customers because of the utility's monopoly power, lack of competition to drive down prices, and its guaranteed financial return on the devices when included in the rate-base.

51 See Lawrence Berkeley National Lab's Integrated Distribution System Planning resource hub, which includes an interactive planning framework, a map and detail on existing planning requirements by state, and information on technical assistance and resources available to PUCs and policymakers.

broader use of integrated distribution system planning practices could promote a more proactive utility investment approach to better consider and use DERs and VPPs. Regulatory approaches requiring or directing utilities to invest in grid orchestration platforms (e.g., DERMS) as part of broader grid modernization efforts can help distribution utilities manage an increasingly complex and digital grid, which also establishes the technology foundation for future VPP deployments.[52]

3. **DER deployment: Implementing or revising programs to increase DER deployments, which enhance VPP potential.** PUCs are studying and establishing methods to increase DER deployments, such as streamlining interconnection processes, establishing customer incentives, and testing pay-for-performance compensation mechanisms and DER-supportive tariffs. DERs can support net cost savings for customers and increase the resources available for DER aggregation.
4. **DER aggregation: Developing DER aggregation models and deployment requirements to enable VPPs.** PUCs are requiring utilities to develop pilots or consider how to aggregate DERs into a VPP program to be used as a grid asset.
5. **VPP operations: Supporting VPP operations to proactively address common VPP deployment barriers.** PUCs are increasingly influencing VPP operations to maximize system value, including by engaging on data access challenges[53] and establishing tariff structures that better compensate VPPs for their full suite of grid benefits (e.g., capacity, reliability, decarbonization impacts, etc.) and enabling value stacking (including stacking across both retail and wholesale market revenue streams).

Specific state examples illustrate how PUCs are putting these types of actions into practice.

Case Study: Colorado PUC, CO

***Colorado PUC** established a performance incentive mechanism to accelerate DER interconnection, helping improve DER deployment to support VPP potential.*

- **Colorado PUC** approved a performance incentive mechanism for **Xcel Energy** to speed up interconnection of DERs (Order 23AL-0188E) in October 2023.[civ]
- The PIM requires Xcel to refund customers 4% of the interconnection fee per day delayed beyond Xcel's internal timeline targets (e.g., 50 days).
- If Xcel interconnects the DER faster than the target timeline, the value would be credited against any penalties accrued for exceeding the target.
- The PIM aims to align Xcel incentives with ratepayer interests to support DER interconnection, enabling faster DER deployment and supporting greater VPP potential at scale.

52 See DOE's Innovative Grid Deployment Liftoff report for additional information on other grid modernization technologies and foundational platforms available to support modernizing distribution grids.

53 See *Chapter 5.iv* for additional detail on VPP-related data access challenges and potential solutions.

Case Study: New York State PSC, NY

***New York State PSC** implemented a value compensation methodology to reward DERs for a range of delivered grid benefits.*

- In 2017, **New York State PSC** implemented a Value of Distributed Energy Resources Value Stack (VDER, or the Value Stack) to better compensate and incentivize DERs for provided grid value.
- The Value Stack includes six values to determine DER compensation:
  - Energy Value (Locational Based Marginal Price, LBMP)
  - Capacity Value (Installed Capacity, ICAP)
  - Environmental Value (E)
  - Demand Reduction Value (DRV)
  - Locational System Relief Value (LSRV)
  - Community Credit (CC)
- This model allows for value stacking across multiple revenue streams (including wholesale market revenues) to fully reward DERs for delivered grid benefits.
- The Value Stack provides location-specific compensation to reward VPPs that have the greatest impact on alleviating distribution system constraints.

Detailed case study provided in Appendix D.ii.

State by state, PUC/PSCs have different policy contexts and starting points of regulatory frameworks that can be used – or adjusted – to encourage VPP deployment. [54] When motivated to support VPP deployment, PUC/PSCs can leverage components of the real-world examples described above to tailor regulatory actions that are appropriate for their state's context and grid objectives.

Regulators have reported success with directing a few staff members to develop simple VPP regulatory frameworks (e.g., a smart thermostat program) and then adding resources and scaling up over time towards more complex regulatory efforts as impacts are proven out and lessons are learned.[cv]

Regulatory approaches will likely continue evolving over time as VPP program design and underlying technology also evolve. To enable continuous improvement, PUCs could consider establishing processes that enable and encourage evolution. For example, the **Hawaii PUC** built in iteration to revisit elements of DER programs (e.g., incentive levels, operational characteristics) every three years with stakeholders to keep pace with an evolving grid.[55] The **Connecticut Public Utilities Regulatory Authority (PURA)** implemented a "regulatory sandbox" program that fosters new grid technology deployments and informs enabling regulation.[56,cvi]

54 For policymakers/regulators considering implementing a VPP initiative, RMI/VP3 defined a set of guiding policy principles that can help inform initial actions to maximize long-term benefit (See Appendix D.v. for the full set of policy principles.

55 See additional detail about Hawaii's DER program evolution in NARUC's Aggregated DER in 2024: The Fundamentals (page 69).

56 Connecticut PURA established the Innovative Energy Solutions Program in 2023 to encourage grid innovation, including defining features such as a four phase process from ideation to scale up, cost recovery guidance, and screening and performance metrics.

4.iii. Supportive policymaker actions for integration into utility planning and incentives

Legislative changes to utility regulations or related policy are often not *necessary* for investor-owned utilities to deploy VPPs or for regulators to take action, but they can be an *accelerant*. Legislation and other policy measures can shorten design and deployment timelines by removing ambiguity about VPP goals and other program parameters or aligning expectations with state energy and climate goals.

At the state level, policymakers (e.g., legislators, governors, tribal governments) can empower PUC/PSCs in states where regulators may not consider it their role to proactively shape VPP programs and/or the processes underpinning their deployment (e.g., filing dockets, RFIs, etc.). In these states, policymakers can accelerate regulatory processes, potentially by years, by providing direction and focus while giving PUCs and utilities room to determine the most effective regulatory frameworks. Similarly, tribal governments can also provide direction to tribal utilities to advance VPP-supportive actions. In Colorado, Massachusetts, and New York, actions by policymakers built on previous PUC actions to strengthen and provide explicit support to grid modernization and VPP supportive efforts.

Three types of actions that state policymakers have recently taken to support VPP deployments include:

1. **Establishing grid modernization policies and VPP-enabling requirements to enhance system planning: Washington State** passed HB 1589 in March 2024 that required utilities to submit integrated system plans. VPP-enabling features include requiring plans to align with state clean energy goals and emission reduction targets.

2. **Requiring utilities and PUCs to develop VPP programs and/or supportive tariff mechanisms: Colorado** passed SB24-218 in May 2024 that requires the state's largest IOU (Xcel) to submit a VPP plan to the PUC. This built on ongoing actions by the **Colorado PUC** to advance VPP programs as part of an effort to serve rising demand while mitigating costs for ratepayers.

3. **Clarifying VPP stakeholder roles and requirements: Texas** legislators passed SB 1699 to establish third-party aggregation requirements for DERs and to authorize the **TX PUC** to establish rules and requirements for DER aggregators.

See Appendix D for a menu of 22 regulatory and policy options to support VPPs (Appendix D.i.), detailed case studies on New York PSC's Value of DER (VDER) Value Stack compensation method and Massachusetts legislation on grid modernization planning requirements (Appendix D.ii.), 6 additional resources (Appendix D.iii.), 9 supportive DOE programs (Appendix D.iv.), VPP policy principles from the Virtual Power Plant Partnership (VP3) (Appendix D.v.), and a summary of existing benefit-cost assessment frameworks available to support VPPs from NARUC (Appendix D.vi.).

Chapter Five: Integrating into wholesale markets

Key takeaways

- In the last decade, wholesale markets have been the primary mechanism to provide and monetize grid services from distributed flexible loads – particularly commercial and industrial loads.
- FERC Order 2222 has the potential to unlock wholesale market participation from an enormous amount of DER capacity. At a time when capacity markets are tight (e.g., PJM), VPP participation in wholesale markets has never been more important for system affordability and reliability.
- Although industry actors have been excited about the potential impact of Order 2222, slow implementation timelines, varied approaches across ISO/RTOs, and obstructive state, ISO/RTO, and utility rules have blocked the full integration of VPPs into wholesale markets.
- Technology, regulatory, and policy solutions are emerging domestically and internationally to remove barriers for VPP integration into wholesale markets. Industry collaboration is needed to share learnings and accelerate implementation.

5.i. VPP wholesale market participation today

In the last decade, wholesale markets have been the primary mechanism to provide and monetize grid services through demand response for distributed loads – particularly commercial and industrial loads. Today, 29 GW of demand response participates in wholesale markets.[cvii]

All seven of the U.S. ISO/RTOs allow wholesale market participation from VPPs that manage demand without exporting power to the grid. Well-established demand response aggregators such as **CPower** continue to focus their business strategy on wholesale markets, which offer large potential revenue streams from the energy, capacity, and ancillary services markets as well as greater long-term revenue certainty given the durability of wholesale markets. In comparison, individual utility-level VPP programs tend to have short-term contracts (1-2 years), which creates greater revenue uncertainty for aggregators.[57]

See Appendix E.i. for a detailed case study on how Leap aggregates demand response to participate in the CAISO market.

While total revenue potential across wholesale markets is large, each ISO/RTO has a unique set of rules and processes that require deep expertise to navigate, creating barriers for new entrants. As a result, participating in wholesale markets may provide lower levels of compensation than current utility-led VPPs receive today. Additionally, most ISO/RTOs only allow large-load demand response and do not yet allow DERs that store or generate energy (e.g., distributed storage and solar PV) to export power to the grid. This limits the value that DERs can bring to wholesale markets to a fraction of their technical functionality.

Streamlining wholesale market integration and allowing the full range of potential grid services from installed DERs could help address increasing capacity constraints that are causing price spikes and diminishing reserve margins across the U.S. For example, **PJM**, an RTO that coordinates wholesale electricity markets in all or parts of 13 states and the District of Columbia, held a capacity auction in summer of 2024 that resulted in final capacity prices nearly 10x higher than the previous year's auction.[58,cviii,cix,cx,cxi]

57 Uncertainty around grid services revenue increases the cost of capital for industry actors investing in VPP participant recruitment and/or DER deployment. Longer-term contracts with greater revenue predictability can reduce the overall cost of VPP deployment, resulting in higher savings to pass on to customers.

58 In early 2024, PJM updated its capacity accreditation methodology to reflect the marginal contribution each resource can provide to system resource adequacy given the anticipated resource mix. As a result, many supply resources (including solar PV, gas, coal, hydropower, demand response) had lower capacity that could bid into the capacity market, resulting in lower capacity. Simultaneously, many existing power plants were forecasted to retire, further constraining supply and increasing PJM capacity prices.

As a result, PJM ratepayers will be responsible for $14.7 billion in capacity costs for the 2025-2026 delivery year, as compared to $2.2 billion for the 2024-2025 delivery year.[cxii,cxiii] In early 2024, PJM updated its capacity accreditation methodology for all supply resources, including demand response. PJM's accreditation is based on PJM's existing requirement that DR resources be available for dispatch only between 10am-10pm during the summer and between 6am-9pm during the winter, even though DR resources could also perform outside these windows – effectively derating demand response because of PJM's rules rather than technological reality.

5.ii. Overview of FERC Order 2222

FERC Order 2222 has the potential to dramatically accelerate national action towards integrating VPPs into wholesale markets, which could maximize the value of DERs in restructured regions and help address rising affordability and reliability challenges to meet demand growth. Issued in September 2020, Order 2222 *requires* the six FERC-jurisdictional ISO/RTOs[59] to establish participation models that enable DER aggregations to participate in energy, capacity, and ancillary services wholesale markets.[60,cxiv]

In issuing the Order, FERC recognized that a much wider range of DERs can provide wholesale market services, including those that export power and smaller individual assets.[61] The Order is meant to offer a path to expand supply-side participation by DERs beyond demand response and place downward pressure on prices in markets with high demand and low supply. However, successful implementation of Order 2222 will require coordinated action from a broad range of stakeholders including ISO/RTOs, utilities, aggregators, regulators, and policymakers across the country.

5.iii. ISO/RTO Order 2222 compliance status

ISO/RTO compliance with FERC Order 2222 requirements has been varied: CAISO, NYISO, and ISO-NE are leading implementation while PJM, MISO, and SPP are seeking to implement much of their Order 2222 compliance proposals several years later. Although all six FERC-jurisdictional ISO/RTOs have filed compliance proposals with FERC, and FERC has issued orders on these filings, **CAISO** and **ISO-NE** are the only ISO/RTOs that have fully complied with the requirements of FERC Order 2222 as of December 2024.[cxv,cxvi]

59 FERC does not have ratemaking jurisdiction with respect to ERCOT in Texas.

60 Specifically, Order 2222 requires each ISO/RTO to (a) develop tariff provisions that ensure that market rules facilitate the participation of DER aggregations, (b) allow DER aggregations to participate directly in ISO/RTO markets, and (c) establish DER aggregators as a type of market participant that can register DER aggregations.

61 FERC declined requiring ISO/RTOs to adopt minimum capacity requirements for individual distributed energy resources to participate in the markets, given those resources would only participate in the markets through a DER aggregation which would act as a single resource. However, some market operators have adopted minimums for individual DERs. For example, NYISO proposed a minimum capacity of 10 kW for each individual DER in any aggregation for a VPP to be eligible to participate, which would exclude many residential DER types.

Order 2222 compliance status

Issue Areas	CAISO	ISO-NE	NYISO	PJM	MISO	SPP
Metering and telemetry system requirements	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance	Not yet in compliance
Participation model	In compliance	In compliance	Not yet in compliance	In compliance	Not yet in compliance	Not yet in compliance
Double counting of services	In compliance	In compliance	In compliance	Not yet in compliance	In compliance	Not yet in compliance
Locational requirements	In compliance	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance
Role of distribution company	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance	Not yet in compliance
Ongoing operational coordination	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance	Not yet in compliance
Small utility opt-in	In compliance	In compliance	In compliance	In compliance	In compliance	In compliance
Interconnection	In compliance	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance
Definitions of DER and DER aggregator	In compliance	In compliance	In compliance	In compliance	In compliance	In compliance
Types of technologies	In compliance	In compliance	In compliance	In compliance	In compliance	Not yet in compliance
Allow a DER to serve as its own aggregator	In compliance	In compliance	In compliance	In compliance	In compliance	In compliance
Min and max size of aggregation	In compliance	In compliance	In compliance	In compliance	In compliance	In compliance
Min and Max size for DER in an aggregation	In compliance	In compliance	In compliance	In compliance	In compliance	Not yet in compliance
Distribution factors and bidding parameters	In compliance	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance
Information and data requirements	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance	In compliance
Role of RERRA	In compliance	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance
Modifications to list of resources in aggregation	In compliance	In compliance	In compliance	In compliance	In compliance	In compliance
Market participation agreements	In compliance	In compliance	In compliance	In compliance	Not yet in compliance	Not yet in compliance
Demand response opt-out	In compliance	In compliance	In compliance	In compliance	In compliance	Not yet in compliance

Legend
In compliance · Not yet in compliance

Source: Lawrence Berkeley National Lab DER Participation in Wholesale Markets Report, FERC filings

ISO/RTO compliance plans exhibit individualized, disparate approaches to DER wholesale market participation, resulting in a patchwork of rules and requirements that make it difficult for aggregators to scale across jurisdictions. Order 2222 did not provide a technical implementation roadmap, leaving it up to the ISO/RTOs to make their own decisions on VPP integration standards and protocols. Market operators are taking different approaches to compliance with varying rules, baselining methodologies, grid services definitions, and operational protocols. For example, **ISO New England** requires telemetry readings to be actual data for all assets while **PJM** allows telemetry readings to be calculated based on a sample of DERs.[cxvii]

While some variation is expected given varying market conditions and needs, the degree of variation across regions is introducing delays in scaling up proven VPP models nationally to address near-term grid needs. For example, one industry analysis estimated that standardizing ISO/RTO metering and settlement approaches alone could create $75B in savings due to reductions in data computing, storage, and management costs.[cxviii]

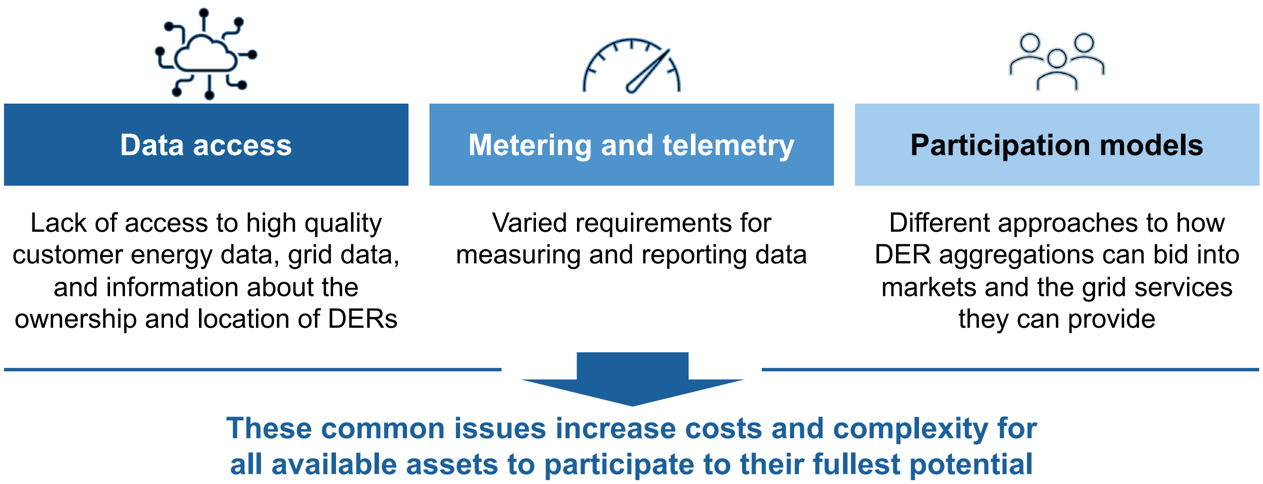
Even in achieving Order 2222 compliance, ISO/RTOs could still limit VPP participation. For example, separate from its compliance with Order 2222, **NYISO** proposed a minimum capacity of 10 kW for each individual DER in any aggregation for a VPP to be eligible to participate, which would exclude many residential DER types.[62,cxix] In California, even though **CAISO** has reached full compliance with Order 2222, **California Public Utilities Commission (CPUC)** does not recognize aggregations of DERs as qualified to provide resource adequacy, which is one of the major barriers for aggregators that want to directly participate in CAISO's resource adequacy construct.[cxx]

62 In a September 2022 presentation, NYISO wrote, 'Given the NYISO's current technical resources and capabilities for initial DER deployment, allowing small (<10 kW) DER will require a substantial amount of additional manual work to complete tasks that are core to the timely participation of DERs.'

5.iv. Common challenges for integration into wholesale markets

VPP aggregators, ISO/RTOs, and utilities have noted three key issue areas that impact VPP integration into wholesale markets.[cxxi]

Common issue areas to VPP integration into wholesale markets



1. **Data access: Lack of access to high quality customer energy data, grid data, and information about the ownership and location of DERs limits aggregators' ability to establish and operate reliable VPPs that can participate in wholesale markets.**

   Hourly and daily customer energy data is required for aggregators to complete wholesale market processes such as receiving customer consent to access data, calculating baselines and performance, and implementing settlement procedures. Most ISO/RTOs require VPP aggregators to use customer energy data from utility-owned meters, yet most utilities limit third-party data access, citing cybersecurity and data privacy concerns. Aggregators must follow varied and often lengthy processes to access customer energy data from utilities, which makes it difficult to know if, when, and in what format data will be shared across utilities even within the same ISO/RTO region.[63] Aggregators have had limited success in improving data access rules despite filing complaints and requesting improvements.[64,cxxii,cxxiii] FERC has stated that customer usage data access is not within FERC's jurisdiction, leaving it to individual ISO/RTOs, states, tribes, or utilities to determine data access policies.[cxxiv]

2. **Metering and telemetry: Each ISO/RTO is developing individual frameworks to determine how to measure and report DER energy data, which increases the complexity and cost for aggregators to deploy and scale VPPs.**

   As relates to Order 2222, "metering" refers to the rules that determine how DER aggregations measure energy injection and withdrawal; "telemetry" refers to how aggregations report the real-time data needed to provide grid services. ISO/RTOs require VPPs to use meter data for planning, operations, and settlement purposes. While the technological capabilities exist to capture this data, such as with

63 For example, sometimes aggregators must email utilities with a form requesting a customer's data. In other cases, utilities have portals where aggregators can access the data directly.

64 For example, CPower, an aggregator who works closely with utilities and supports utility programs, brought a complaint before FERC (EL23-104) showing that lack of data access limits demand response participation in wholesale markets. CPower argued that PJM rules limit the participation of aggregators by refusing to allow statistical sampling for measurement purposes. If statistical sampling were allowed, CPower could measure behavior of a representative sample of customers in their aggregation who have advanced metering infrastructure (AMI) and extrapolate the performance to the full aggregation. PJM, however, requires measurement from every individual meter for interval metered customers, which dramatically reduces CPower's capacity contribution because utilities in the region block access to data from many meters where customers could otherwise participate. FERC denied the complaint and noted that customer usage data access is not within their jurisdiction. Additional detail provided here: CPower Statement Regarding September 19 FERC Decision - CPower Energy; Order Denying Complaint re Enerwise Global Technologies, LLC v. PJM Interconnection, L.L.C. under EL23-104

advanced metering infrastructure (AMI)[65] or metering manufactured into devices, most utilities do not measure demand at this granularity and ISO/RTO telemetry requirements can be too costly or complex for certain asset types.

For Order 2222 compliance, FERC did not provide strict guardrails for either metering or telemetry, approving each ISO/RTO's framework so long as they justify how their requirements are just and reasonable and do not pose an unnecessary and undue barrier to individual DERs joining an aggregation. This has led to a wide variety of approaches that are seeking to balance data granularity with the costs of reporting high frequency data. For example, **NYISO** requires six-second telemetry for every DER asset that is at least 100 kW, regardless of the service provided. **PJM** allows one-minute scans for resources that do not provide regulation services and entirely exempts DERs under 10 MW from telemetry reporting.[cxxv]

3. **Participation models: ISO/RTOs are taking different approaches to develop market participation rules that define how DER aggregations are allowed to bid into wholesale markets and the grid services they can provide, making it difficult for aggregators to replicate similar models across markets.**

   ISO/RTOs have multiple choices in determining market participation rules that define how aggregations bid into the market. An ISO/RTO can choose between requiring aggregators to comply with rules already established for existing supply resources (e.g., applying rules for utility-scale batteries to aggregations of residential behind-the-meter batteries), creating new participation models specifically for DER aggregations, or using a hybrid approach.

   There are trade-offs between these approaches. For example, leveraging models for existing supply resources could avoid slow, expensive processes to create new participation rules, but may restrict participation from aggregations that have multiple types of DERs. Creating a single, new participation model for DER aggregations could simplify aggregator choice on how to participate in a wholesale market but may require all types of DER aggregations to comply with the same rules (e.g., battery-only aggregation may have the same rules as an aggregation with batteries, thermostats, and commercial & industrial loads).[66] Offering a hybrid approach, as **NYISO** and **ISO-NE** are currently suggesting, allows aggregators to choose the option that is highest value to their business model.[cxxvi]

Outside these three challenges, additional issue areas include how to coordinate and compensate dual participation of DERs across wholesale and retail markets[67] (i.e., avoiding 'double counting' for the same service), locational requirements on aggregating DERs across eligible pricing nodes, and ongoing coordination between distribution utilities, market operators, and aggregators.

65 AMI or 'smart meters' are used to measure a customer's energy consumption during set time intervals. AMI includes technologies to measure and communicate energy use and other data and notifications at intervals that are granular enough to support grid and market operations.

66 ISO-NE created multiple DER aggregation participation models to address the drawbacks of creating only one new participation model that would apply to every type of DER aggregation.

67 There is still a role for utilities to play to compensate VPPs for distribution benefits separately and in addition to wholesale market compensation to cover the full value stack of potential services. A VPP that delivers benefits to the transmission system and to the distribution system (even if during the same event) can be fairly compensated for both.

5.v. Supportive actions for VPP integration into wholesale markets

ISO/RTOs, state regulators, utilities, and aggregators can collaborate to streamline learnings and converge on comparable approaches that address common issues, enabling VPPs to better meet near-term grid capacity needs at lower costs for ratepayers.

There are multiple solutions available globally that could be adopted to support VPP integration into wholesale markets.

Case Study: Australian Energy Market Operator (AEMO)

***Australian Energy Market Operator** established a centralized, standardized DER registry to provide visibility to DER specifications and location to eligible entities.*

- In 2020, the **Australian Energy Market Operator (AEMO)** established a centralized DER registry to better manage the grid, improve system reliability as the grid becomes more decentralized, and deliver energy at a more affordable price.
- The register provides a common, standardized information fact base with visibility to DER specifications (e.g., type, capabilities, resource ownership) and location.
- Customers, AEMO, distribution utilities, DER industry, and other third parties (such as emergency services) can access the register.
- Entities are required to provide data in certain formats and timelines; for example, utilities are required to provide DER information in accordance with the DER Register Information Guidelines under the National Electricity Rules to ensure standardization, and DER installers are required to submit data within 20 days of installation.[68,cxxvii,cxxviii,cxxix]

Case Study: Ontario Independent Electricity System Operator (IESO)

***Ontario Independent Electricity System Operator (IESO)** created market-wide standards for meter registration to standardize data collection and reduce IT costs*

- **Ontario IESO** has established market-wide standards for meter registration across numerous distribution utilities and 5 million smart meters.[cxxx]
- Market rules require that each metering installation used for settlement purposes is on a list of pre-approved meters established by IESO that meet specific performance standards (e.g., accuracy, security).
- Establishing a market-wide approach to metering simplifies and standardizes data collection while reducing IT costs to develop, manage, and protect the database.
- This spurred additional engagement with various grid stakeholders to expand third-party access to this database, including for demand response aggregators.[cxxxi,69]

See Appendix E for 6 case studies on actions ISO/RTOs have been taking domestically and internationally to integrate VPPs into wholesale markets (Appendix E.iii.), 6 additional resources (Appendix E.iv.) and 3 supportive DOE programs (Appendix E.v.).

68 The Australian Energy Market Commission made a rule obligating AEMO to establish this register in the National Electricity Market in September 2018. AEMO engaged with a wide range of partners, including utilities and industry groups, to design the register and align on the corresponding data sets and data collection processes.

69 Another example is ConnectedSolutions, which has metering authority across multiple utilities in Massachusetts. Common program design across utilities enables standardization of data access, dispatch, monitoring and verification, and DERMS while providing economies of scale for enrollment.

In parallel with ISO/RTO implementation of Order 2222, state policymakers and regulators can act to build enabling VPP regulations and policies that further integrate VPPs into wholesale markets. Example actions include:

- **Lifting state-level 'opt outs' on Order 719:** FERC Order 719 was introduced in 2008 to allow demand response to participate in wholesale markets alongside traditional supply-side resources.[cxxxii] However, states were allowed to 'opt out,' by prohibiting third-party aggregators from directly contracting with customers. These 'opt outs' have greatly limited DER market participation in these states. **Missouri PSC** ruled to partially lift its FERC Order 719 opt out in October 2023 by allowing energy customers above 100 kW (commercial & industrial loads) to enter **MISO's** demand response market.[cxxxiii] By starting with commercial and industrial loads, Missouri state regulators and utilities could test and learn to inform more complex future policies and VPP integration approaches. **Michigan** and **Wisconsin** have also partially lifted their initial 'opt out' of Order 719. Ten states still have 'opt outs' in place for Order 719.[70]
- **Determining the state regulator's role in Order 2222 implementation: Pennsylvania PUC** issued an Advanced Notice of Proposed Rulemaking in February 2024 to investigate the PUC's role in Order 2222 implementation. Topics identified for stakeholder input included DER interconnection rules, metering requirements, data sharing protocols, and cost allocation processes.[cxxxiv]
- **Requiring utilities to meet data sharing standards: Connecticut PUC** created a Data Access and Privacy Framework to clarify data requirements for IOUs deploying AMI, including data sharing expectations with third-party aggregators.[cxxxv] In response, **Eversource** agreed to adopt Green Button Connect to enable third-party data access.[cxxxvi] Similarly, **Rhode Island PUC** is requiring **Narragansett Electric Company** to submit a plan about data access (including for VPPs) as part of the utility's planned investment into AMI.[cxxxvii]

70 The ten states that continue to fully opt out of Order 719 are Arkansas, Indiana, Iowa, Kentucky, Louisiana, Minnesota, Mississippi, Montana, North Dakota, and South Dakota.

Closing

The U.S. electric grid is increasingly under stress from rising peak demand, climbing utility investments in aging distribution systems and other assets, and increasingly frequent blackout-inducing extreme weather events. "**Virtual Power Plants" or "VPPs" are cost-effective solutions that can be deployed at scale in a short timeframe to maximize the use and value of existing grid infrastructure, minimize costs to ratepayers, and ensure a resilient, reliable, and secure grid for all Americans.**

VPP awareness and deployment is growing, as demonstrated by the 75 case studies, 50 DOE supportive programs, and 20 resources highlighted in this report. Just in the last year, utilities and aggregators have launched increasingly sophisticated VPPs that provide distribution grid benefits in addition to system peak shaving; state regulators and policymakers have implemented VPP-supportive policies; and industry groups have released new solutions to address gaps identified in the 2023 VPP Liftoff Report.

Momentum is building, but the success of many of these efforts hinges on further action and continuous improvement. Many of the case studies presented in this report are early indications of progress, and their full impacts remain to be seen. By tracking, disseminating, and acting upon lessons learned from VPPs across the country (and internationally), stakeholders can accelerate near-term VPP deployment in the pursuit of a more resilient, reliable, and low-cost energy future.

Appendices

Each Appendix directly relates to the five chapters in the main report. Each chapter of the Appendix includes additional case studies of how various industry actors are taking action on the five imperatives today, detailed overviews of select case studies, key resources to support the work of practitioners, and example supportive actions from the Department of Energy.

Appendix A: Expanding DER adoption with multifaceted benefits

A.i. Levers to expand access to VPP participation, DER ownership, and community-wide benefits

This section provides a list of barriers to expanding access to VPP participation, DER ownership, and community-wide benefits as well as supportive actions that various stakeholder groups can take to address these barriers.

Access to VPP participation

Primary barriers	Levers by stakeholder group
Low awareness of VPP participation opportunities	» **Utilities, policymakers, philanthropy organizations:** Fund and educate community organizations to educate consumers on VPP participation opportunities and consumer benefits » **DER OEMs, DER retailers, utilities, community organizations:** Publicize VPP participation opportunities and educate consumers on their benefits
Qualifying DER too expensive	» **Utilities:** Prioritize integration of low-cost DERs for VPP programs
Community mistrust *(especially for underserved communities due to historic divestment)*	» **Utilities, aggregators:** Partner with trusted community organizations and inform program launch with thoughtful community outreach » **Utilities:** Set equity targets for customer programs; track and publicly report progress against key metrics » **Policymakers:** Require strong customer protections for VPP programs
Lack of reliable connection	» **Policymakers:** Ensure allocation of available broadband grants[71] to rural communities
Lack of flexibility in energy usage[72]	» **Utilities, aggregators:** Offer flexible, opt-out options for DER orchestration

Access to DER ownership

Primary barriers	Levers by stakeholder group
High upfront DER costs with limited low-cost financing options	» **Policymakers, utilities:** Provide upfront, tiered incentives with caps » **Policymakers, regulators, utilities:** Allow incentive stacking to unlock cheapest cost » **Utilities, regulators, policymakers:** Leverage inclusive utility investments to provide access to low-cost financing options
Split incentives between property owners and tenants	» **Utilities, regulators:** Include multi-family housing, especially affordable multi-family housing, in DER programs » **Utilities, regulators:** Develop tariffs to share benefits of DER programs between property owners and tenants
Additional home integration costs	» **Utilities, policymakers:** Ensure upgrade costs (e.g., minor construction) qualify for financing and incentive programs
Lack of education on DERs and available incentives	» **Utilities, policymakers, philanthropy organizations:** Fund and educate community organizations to conduct outreach to match appropriate incentive programs to eligible consumers, particularly in underserved communities

71 Broadband access is important for VPPs that rely on Wi-Fi connection to the device (either directly to the aggregator platform, or through a consumer app that in turn connects with the aggregator's platform). Some VPPs use other communication mechanisms; for example, radio frequency has been used in water heater programs for decades.

72 Low-income communities and other underserved communities may not have the ability to shift or reduce their energy usage as they are already trying to minimize energy usage to reduce utility bills. Lack of flexibility might impact their desire to enroll in a VPP which may cede control of their device at times that may be inconvenient to their circumstances.

Access to community-wide benefits

Types of VPP benefits	Levers by stakeholder group
Reduced pollution burden	» **Utilities, regulators:** Consider VPP deployment prior to approving construction of a new fossil fuel-powered peaker plant » **Utilities, regulators:** Deploy VPPs in communities which have a disproportionate number of fossil fuel plants sited nearby to reduce usage of existing polluting infrastructure
Reduced impact of outages	» **Utilities, regulators:** Target VPP deployment to communities with higher rates of system outages » **Policymakers, regulators:** Prioritize VPP deployment in disaster recovery and resiliency work » **Utilities:** Explore deploying microgrids for vulnerable parts of the grid, wherein the microgrid's DERs can either be islanded for resilience (e.g., at local community centers) or used for bulk grid services to help offset their cost
Lower utility bills	» **Utilities, regulators:** Share cost savings from VPP deployment with all ratepayers[73] » **Utilities:** Spread VPP economic benefits out over the year to minimize large swings in energy bills and ensure consistent bill reductions
Local workforce development	» **Policymakers, regulators:** Partner with Registered Apprenticeship Programs and local technical schools to create pipeline of high-quality workforce in local communities for DER installation » **Utilities:** Partner with a local contractor base for DER installation

A.ii. Case studies by lever

This section provides case studies of VPP and related deployments that showcase the real-life applications of the levers identified in Appendix A.i. Two of the case studies, Roanoke Cooperative's Upgrade to $ave program and San Diego Community Power's Solar Battery Savings program, have detailed overviews provided in Appendix A.iii.

Access to VPP participation

Lever	Example
Prioritize integration of low-cost DERs for VPP programs	Shifted Energy's 2.5 MW VPP in Hawaii installs smart, programmable water heaters for VPP participation.[cxxxviii] **Allowing low-cost DERs such as water heaters to participate creates more inclusive programs** for priority populations.[cxxxix] Shifted Energy has partnered with local community organizations to reach more than 3,000 families, including low-income residents in areas where trust in the utility is low and would otherwise prevent customers from enrolling in VPP programs that offer energy bill savings.[74,cxl,cxli]
Fund trusted community organizations and inform program launch with thoughtful community outreach	Mass Saves, a collaborative of Massachusetts' electric and natural gas utilities and energy efficiency service providers[cxlii], established the Community First Partnership to increase participation in energy efficiency programs. This **partnership funds community-based organizations, who have the knowledge of and relationships with local communities, to conduct targeted outreach** for these programs, prioritizing renters, low- and moderate-income households, customers who speak languages other than English, and small businesses in participating communities.[cxliii] Mass Saves itself is funded by energy efficiency charges on all customers' gas and electric bills.[cxliv]

73 Utilities that set participant incentive levels high enough to attract large-scale participation, but low enough to be measurably cheaper than alternative grid investments can pass on the savings to all customers by avoiding or deferring unnecessary increases in the ratebase.

74 Smart thermostats are also effective DERs to prioritize for equity considerations, given their affordability and short payback periods.

Access to DER ownership

Lever	Example
Use inclusive utility investments to provide accessible financing options	Roanoke Cooperative (RC) launched the Upgrade to $ave program in 2016 to reduce energy bills for the fourth lowest income Congressional district in the U.S. The Board of Directors targeted upgrading 1000 homes with energy efficiency and demand response measures. They approved use of the Pay As You Save® (PAYS®) system, an inclusive utility investment model, for the design of the utility program and tariff.[75] **RC paid upfront for all cost-effective energy upgrades at a member's residence and recovered its costs through a fixed, monthly cost recovery charge that was lower than the estimated savings from the upgrades on an annual basis.**[cxlv,76] Participating members reduced electricity usage by ~20% because of upgrades and the utility realized peak demand savings of ~20% during summer and winter peaks. *Detailed case study provided in Appendix A.iii.*
Provide upfront incentives that stack with available programs	San Diego Community Power (Community Power) is a Community Choice Aggregator that launched the Solar Battery Savings program in 2024. **The program was designed to benefit all customers through upfront incentives[77] to lower the initial cost of home solar and battery storage resources** and provided ongoing performance incentives for battery power provided during on-peak periods. Community Power **worked with state and local programs to ensure their incentives could stack with programs** such as California's DAC-SASH and SGIP programs[78] and the City of San Diego's Solar Equity program to allow priority populations to cover the entire cost of solar and storage resources through available incentives. *Detailed case study provided in Appendix A.iii.*
Include multi-family housing in DER programs and share benefits between property owners and tenants	Solar energy company PearlX partnered with SolarEdge, a distributed solar OEM, on Project TexFlex to make community solar and storage programs accessible to tenants in multifamily communities around Texas.[cxlvi] PearlX addresses the split incentive challenge associated with rental units by paying the property owner for the right to install the solar and batteries and passing on benefits of lower energy bills and backup power during outages to renters. PearlX manages the assets, providing flexibility and capacity services to the energy market. This approach uses a non-credit based underwriting method, which allows tenants to access the rewards of solar generation and battery storage without having to provide their credit score. Pilot results indicate solar energy supplied 46% of participating tenant's daily energy consumption, reducing grid demand for ERCOT, and **saving tenants $60 per month on their energy bills on average**.[cxlvii] PearlX is now exploring expanded offerings to help build resilience for multifamily communities while also providing new amenities to residents and supporting the grid.

75 PAYS Essential Elements and Minimum Program Requirements provides additional information on the utility program requirements for a PAYS program and PAYS model tariff shares the tariff design.

76 The program's annual cost recovery is set at less than the estimated savings from the upgrades to ensure immediate reductions in energy costs, and much larger cost reductions once the utility recovers its costs and ends the on-bill charge.

77 Upfront incentives can be more effective at overcoming initial barriers to DER adoption than incentives paid at a later date, such as rebates. This is because customers would have to pay the upfront cost of the resource and wait to receive the rebate with limited visibility and certainty on when the incentive would be provided. Even rebates that cover 100% of the cost of the underlying asset may not be effective, especially for underserved communities.

78 DAC-SASH is the Disadvantaged Communities – Single-Family Solar Homes program developed by the California Public Utilities Commission (CPUC) and administrated by GRID Alternatives. This state program provides $8.5 million in incentives annually to help homeowners in disadvantaged communities go solar. SGIP is the Self-Generation Incentive Program developed by the California Public Utilities Commission to provide rebates for qualifying distributed energy systems on the customer's side of the utility meter, including advanced energy storage systems, wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, and fuel cells.

Include affordable multi-family housing in DER programs and share benefits between property owners and tenants	PowerTree is working with a 40-unit low-income apartment building in central California to provide BTM solar and batteries. PowerTree works with the property owner to install these assets behind-the-meter and orchestrate them to optimize energy usage. **Renters immediately benefit from lower energy bills, and property owners benefit from a slight increase in rent**, which increases the cash flows of the property and the equity value of the building. The savings in energy bills offset the rent increase, with households able to save $700 in total per year on net given 60% to 100% of tenant load is served from the onsite solar and storage, and an average 31% peak reduction for the building.
Address necessary home upgrades for income-eligible homes	Missouri utility Evergy is using $1M of their Income-Eligible Single Family[79] budget to **help homes that have been deferred for weatherization upgrades to receive the necessary repair work to qualify for existing programs.** Evergy is leveraging a partnership with nonprofit Bridging the Gap to make the necessary structural or home health repairs through local minority contractors. Evergy is also providing income-qualified customers (200% Federal poverty level) free energy-savings items, such as adhesive weather strips, 2-pipe insulation pieces, and switch and outlet gaskets on their online Offer Center to provide a multi-channel approach in increasing home eligibility for their programs.
Bundle the DER purchase and installation process to streamline customer experience	SMUD partnered with Uplight Marketplace to provide instant rebates for EV chargers with bundled installation offers and prequalified installation incentives. Chargers with upfront rebates at the point of purchase are 3 to 5 times more likely to sell on the marketplace than a non-rebated charger. Uplight partnered with Qmerit, a national network of electricians certified to install Level 2 chargers, to schedule charger installations when customers purchase the charger from their utility website. **40% of customers who received quotes scheduled and completed their charger installation by Qmerit.**
Conduct outreach and education to match appropriate incentive programs to eligible consumers	A team from Colorado School of Mines is working to upgrade 16 homes in a manufactured home community[80] in Lake County, Colorado by providing new insulation, LED lighting, high-efficiency furnaces, with plans to install electric heat pumps and batteries in the next few months. Funding was provided by the Weatherization Assistance Program (WAP) and DOE grants. The team **surveyed every participating unit to ensure qualification for the program before the time-intensive application process was started**. Their team is now working to help residents subscribe to Xcel Energy's community solar garden which will credit homeowners on their energy bills for solar energy provided, reducing energy bills.[cxlviii]

79 Evergy has a Low-Income Single-Family program to provide assistance for income-qualified households to overcome structural or home health barriers that otherwise prevents the resident from receiving needed weatherization upgrades.

80 Manufactured homes are energy-intensive, and residents of these homes report high energy insecurity. Many manufactured homeowners are unable to access home equity loans to finance major renovations, making it difficult to adopt distributed energy resources and energy efficiency upgrades.

Access to community-wide benefits

Lever	Example
Deploy VPPs in underserved communities to reduce usage of existing polluting infrastructure	Dominion Energy initiated its Electric School Bus Program in 2019 to assist public school districts in Virginia in overcoming the challenges associated with electric school bus adoption and to advance bi-directional EV Charging and Vehicle-to-Grid (V2G) capabilities. The initial pilot phase of the program commenced in 2019, during which Dominion Energy collaborated with 15 public school districts in Virginia to deploy 50 electric school buses across Dominion Energy Virginia's service regions and underserved communities. Since 2021, funding from the Virginia Department of Environmental Quality (DEQ) and the EPA Clean School Bus Program have provided additional resources to promote electric school bus adoption, with a focus on rural, low-income, and poor air quality districts. Currently, public schools in Virginia that receive EPA funding can partner with Dominion Energy, which will cover the costs of chargers, infrastructure, and installation to support the electric school buses. In return, Dominion Energy is granted the ability to use the buses and chargers for V2G during summer vehicle dwell times. **The program enables school districts and underserved communities to benefit from electric school buses, including improved air quality (with air quality inside a diesel bus being five times worse than outside the bus), decreased noise pollution, and reduced operational and maintenance costs for schools (up to a 60% reduction in costs)**.[cxlix]
Target VPP deployment to communities with higher energy burdens and / or higher rates of system outages[81]	Nimiipuu Energy, a tribally owned energy company, is installing solar and battery systems in tribal homes of the Nez Perce Tribe[cl] to eliminate / lower power bills, decrease dependency on grid supplied power (specifically power generated by the Snake River Dam), and build tribal energy independence. Each home is receiving a rooftop solar array and two Tesla Powerwalls. Tribal nations have reported experiencing outages over six times more frequently than the national average.[cli] **Building this community-owned VPP is meant to provide income for the Tribe while eliminating / lowering power bills for residents**.[clii]
Prioritize VPP deployment in disaster recovery and resiliency work[82]	In 2017, Hurricanes Irma and Maria devastated Puerto Rico's grid and communities. **Since then, significant efforts to prioritize DER adoption in disaster recovery have led to high levels of residential solar PV and battery storage resources.** Puerto Rico's electric utility provider, LUMA, launched the Customer Battery Energy Sharing Program (CBES) in late 2023. Serving primarily residential customers through a number of aggregators[cliii], CBES includes over 7,000 participants and provides 28 MW of available capacity. The program compensates participants via aggregators $1.25/kWh for battery energy supplied during events. Last year, 53 events were called, dispatching 23 MWh of energy. LUMA plans to propose a permanent version of the program by early January 2025.[cliv,clv]
Explore VPP islanding for community centers, especially in disaster-prone areas	In Louisiana, the Community Lighthouse Project has built solar and storage systems on churches to transition these buildings into self-sustaining microgrids. Churches such as First Grace United Methodist Church **operate during times of emergency to provide a haven for their communities**.[clvi]

81 Another great example is California's SGIP program which offers rebates for installing energy storage technology that can work during an outage at residential and non-residential buildings. The program prioritizes communities that live in high fire-threat areas, communities that have experienced two or more utility Public Safety Power Shut-off events, and low income and medically vulnerable households.

82 According to the U.S. News and World Report, racial minorities may have a higher social vulnerability to natural disasters in the U.S. based on a "National Risk Index."

A.iii. Detailed case studies

Detailed case study #1: Roanoke Cooperative's Upgrade to $ave Program

Inclusive utility investment reduces upfront cost barriers to adopting water heater control switches and smart thermostats.

VPP summary			
Utility	Roanoke Cooperative (RC)	**VPP size** *(as of November 2024)*	1.75 MW (with plans to double, 2.5-3% of system peak)
Utility type	Rural electric cooperative (distribution cooperative)	**Type of DERs**	Water heater control switch, smart thermostat, efficiency[83]
Market structure	Within organized market (PJM), utility does not own generation	**Upfront investment cost**	$4.5M including efficiency and flexible demand
Location	North Carolina	**Time to operationalize**	12 months
Size of utility	14,000 member-owners (60-70 MW system peak)	**Number of customers enrolled in VPP**	750 (5%)
Compensation structure	• Upfront incentive: $950 (smart thermostat and water heater control switch were provided for free) • Performance incentive: $4 monthly bill credit for participating customers (Roanoke Cooperative Smart Grid Device program)		
Grid services	• Peak shaving (summer and winter)		

Utility objectives with VPP program *(not exhaustive)*

- **Reduce energy bills** by upgrading 1000 homes (7% of member base) with energy efficiency (EE) and demand response (DR) measures to reduce system-wide peak demand and deliver services at lower cost
- **Enable widespread accessibility** by addressing barriers of high upfront costs of resources, low credit scores limiting traditional low-cost financing options, and limited willingness to take on debt

83 Although energy efficiency upgrades are not considered distributed energy resources in this report, investments in EE help reduce demand for individual households and across the system.

Program summary

Roanoke Cooperative (RC) launched the Upgrade to $ave program in 2016 to reduce energy bills for the fourth lowest income Congressional district in the U.S., where average annual energy costs are more than 6%[84] of the median income. The Board of Directors targeted upgrading 1000 homes with energy efficiency and demand response measures. They approved use of the Pay As You Save® (PAYS®) system, an inclusive utility investment model, for the design of the utility program and tariff.[85]

In this program, RC paid upfront for all cost-effective energy upgrades at a member's residence and recovered its costs through a fixed, monthly cost recovery charge on the bill of participating members that was lower than the estimated savings from the upgrades on an annual basis.[clvii,86] To enroll customers, RC assessed the energy savings potential of the building rather than the owner's income or creditworthiness, allowing all members to access low-cost financing options.[87]

Participating members reduced electricity usage by ~20% because of upgrades and the utility realized peak demand savings of ~20% during summer and winter peaks.[88] Including the cost of capital and program operation costs, the utility sees $2M+ NPV over the lifetime of the upgrades for those already installed, excluding the continuing cash flow value from exercising demand response.[clviii]

Other programs are exploring similar solutions to improve accessibility to DERs:

- Duke Energy's Improve and Save program is leveraging Roanoke's experience to offer inclusive utility investments in heat pumps while it is also piloting a VPP called Power Pair.[clix]
- Illinois' Commerce Commission is guiding development of the Equitable Energy Upgrade Program required by the state's Climate and Equitable Jobs Act with essential elements that are similar to Pay As You Save® and it includes the potential to accelerate the adoption of rooftop solar and storage for low-income customers.

Key success factors to expand DER adoption with multifaceted benefits *(not exhaustive)*

Leverage innovative financial solutions, such as a utility investment that deploys money-saving distributed energy upgrades at customer locations, including demand flexibility

Partner with a trusted organization that has instituted these programs before to maximize operational efficiency and member-owner benefits

Build significant consumer protections into program design to ensure installation quality, realization of energy savings, and associated reduction in energy bills, with protocols to suspend or adjust cost recovery charge, if needed[clx]

84 Communities where energy costs are more than 6% of income are typically considered communities with high energy burdens. The national average, in comparison, is 2.9%.

85 PAYS Essential Elements and Minimum Program Requirements provides additional information on the utility program requirements for a PAYS program and PAYS model tariff shares the tariff design.

86 The program's annual cost recovery is set at less than the estimated savings from the upgrades to ensure immediate reductions in energy costs, and much larger cost reductions once the utility recovers its costs and ends the on-bill charge.

87 After running the program for 2 years, REC transferred program management to EEtility, an operator that was managing Ouachita Electric Cooperative's PAYS® program, which was producing better results. EEtility introduced several best practices that improved energy savings by 46%, peak load reductions by 71%, and member acceptance of offers by 17%. Best practices included targeted outreach to homes with high energy use per square foot and direct installation of low-cost upgrades for homes that were initially deferred from enrollment due to structural repair needs. At no cost to the residents, these homes received LED lights, smart strips, aerators, water heater blankets, and AC coil cleaning.

88 Roanoke is leveraging North Carolina Electric Membership Cooperation's (NCEMC) DERMS platform, which is an OATI product, to shed or shift demand from the distributed energy resources.

89 Inclusive utility investments have emerged as a more equitable solution with strong consumer protections that has been implemented by 23 utilities in 10 states, with most choosing to apply the Pay As You Save® (PAYS®) system to implement.

Detailed case study #2: San Diego Community Power's Solar Battery Savings Program

Upfront, stackable incentives provide opportunity for no-cost solar and batteries to qualified priority populations.

VPP summary			
Utility	San Diego Community Power	**VPP size** *(as of November 2024)*	7.3 MW (0.4% of system peak)
Utility type	Community Choice Aggregator	**Type of DERs**	Solar, BTM battery
Market structure	Within organized market (CAISO), utility does not own generation	**Upfront investment cost**	$11.5M with 45% ($5M) as cost-neutral through RA savings
Location	California[90]	**Time to operationalize**	12 months
Size of utility	1 million customer accounts	**Number of customers enrolled in VPP** *(as of November 2024)*	1,600[91] (~0.2%)
Compensation structure	» Upfront incentive: • Market Rate: $350/kWh for storage • Underserved Community Rate (e.g., CARE/FERA and/or Communities of Concern): Up to $450/kW-AC for solar and up to $500/kWh for storage » Performance incentive: $0.10/kWh of battery power discharged during on-peak periods		
Grid services	» Daily load cycling (charging during the day, discharging during daily two-hour peak window)		

Utility objectives with VPP program *(not exhaustive)*

- **Improve outcomes for underserved communities** by allocating 50% of budget for solar and storage incentives to Communities of Concern
- **Decarbonize power supply** by charging batteries with solar during the day and using daily during peak hours to reduce emissions
- **Lower costs and energy bills** by utilizing battery during on-peak periods to realize $5M of resource adequacy savings, which reduces on-peak consumption system-wide and lowers utility bills for all customers

90 San Diego Community Power operates in seven cities in San Diego County in California.

91 This program was launched in August 2024. The program hit its budget cap of ~$11.5M in **3 months** (August – November), indicating high customer interest. 1,600 customers have been approved to enroll in the program as of November 2024, with 200 customers fully operationalized and providing daily dispatch from their batteries.

Program summary

San Diego Community Power (Community Power) launched the Solar Battery Savings program in 2024 to support customers and the solar and storage industry in the transition from net energy metering (NEM) to net billing tariff (NBT).[92] Community Power (CP) used a portion of the expected savings in the transition from NEM to NBT and resource adequacy savings from leveraging batteries during times of peak demand to fund the program.

The program was designed to benefit all customers through upfront incentives[93] to lower the initial cost of home solar and battery storage resources and provided ongoing performance incentives for battery power provide during on-peak periods. Community Power tailored incentives to provide priority populations[94] (i.e., CARE/FERA[clxi] and / or Communities of Concern[clxii]) with higher incentives to meet their needs and improve equity outcomes, embedding equity goals and metrics into program design from the start. Community Power worked with state and local programs to ensure their incentives could stack with programs such as California's DAC-SASH and SGIP programs and the City of San Diego's Solar Equity program to allow priority populations to cover the entire cost of solar and storage resources through available incentives. Prioritizing a no-cost solution for the most energy burdened communities is critical to ensure realization of direct and immediate benefits.

Community Power also led contractor outreach and training prior to program launch to ensure workforce development opportunities offer accessible training, education, and contracting opportunities to a local contractor base. Community Power continues to accept new contractor applicants and tracks participation of all approved contractors, including minority-owned, for the solar and battery storage installations.

Other programs are deploying similar solutions to improve accessibility to DERs:

- New Mexico's Home Electrification and Appliance Rebate (HEAR), funded by the Inflation Reduction Act of 2022, was launched as a coupon-style incentive program to provide upfront discounts of up to $1,600 off insulation, air sealing, and ventilation for low-income, single-family homeowners.
- New York utility Orange & Rockland partnered with Sunrun, a distributed solar provider, to launch a 2 MW VPP in NY with **over 300 solar and storage systems, 50% of which are in areas designated as a 'disadvantaged community**' by the state. Participating customers who were installing solar from Sunrun received upfront incentives to install a free or heavily discounted home battery when enrolling in the 10-year program.[clxiii,clxiv,95]

Key success factors to expand DER adoption with multifaceted benefits *(not exhaustive)*

- **Redirect system cost savings to all customers**
- **Provide higher, upfront incentives** to priority populations to minimize or eliminate costs of adopting distributed solar and behind-the-meter batteries that can stack with available state and Federal programs
- **Partner with a local contractor base for DER installation** to build local workforce development opportunities through these programs (38% of over 50 local contractors approved are disadvantaged business enterprises or DBEs; 6% are represented by a union)

92 Net billing tariff provides greater economic value for installing solar and storage rather than stand-alone solar.

93 Upfront incentives can be more effective at overcoming initial barriers to DER adoption than incentives paid at a later date, such as rebates. This is because customers would have to pay the upfront cost of the resource and wait to receive the rebate with limited visibility and certainty on when it would come through. Even rebates that cover 100% of the cost of the underlying asset may not be effective, especially for underserved communities.

94 CARE (California Alternative Rates for Energy) and FERA (Family Electric Rate Assistance) are California-specific programs to provide discounts to low-income customers on their electric and natural gas bills. Communities of Concern are disadvantaged communities identified by the Cities of San Diego and Chula Vista through their Climate Equity Index reports.

95 The VPP was initiated by O&R and approved as a demonstration project by the NY Department of Public Service. O&R conducted targeted outreach to underserved communities by mailing brochures to every customer living in an area designated as a 'disadvantaged community'.

A.iv. Key resources for practitioners

- **Clean Energy Financing Toolkit for Decisionmakers** (EPA) provides an overview of available financing programs and policies that state, local governments, and other industry actors use to support investments in clean energy (including inclusive utility investments).
- **Practical Guide for Distributional Equity Analysis for Energy Efficiency and Other Distributed Energy Resources** (May 2024, DOE) shares an analytical framework for utilities, regulators, communities, and other stakeholders to answer questions about the equity implications of utility investments and to embed implications alongside traditional cost-effectiveness analyses.
- **US DER Resource Outlook 2024** (June 2024, Wood Mackenzie) provides analysis of DER deployment and market size from 2019-2028.

A.v. Actions from the Department of Energy

- **Loans and Loan Guarantees** to support VPP projects with a focus on low- to moderate-income communities, including lowering the cost of financing for VPP-eligible DERs
- **Home Energy Rebates** to reduce the cost of efficiency retrofits and electrification measures in homes and other buildings, providing low and moderate-income families up to $14,000 for products like electric heat pumps, electric stoves, and more
- **Weatherization Assistance Program** for energy efficient and electric technologies in low-income households, including improved insulation to help reduce total energy bills
- **Low-Income Energy Affordability Data (LEAD) Tool** to help states consider strategic deployment of funding relative to energy burden and household income, among other building characteristics
- **Clean Energy Funding and Technical Assistance** to provide no cost technical assistance to tribal entities and funding for planning and deployment of energy solutions
- **Technical Assistance for New and Stretch Code Adoption** for adoption and enforcement of new and stretch building codes
- **Training for Residential Energy Contractors** to fund state energy offices so they can train, test, and certify residential energy efficiency and electrification contractors
- **Energy Efficiency Grants** for energy efficiency audits, upgrades, and retrofits, including for deployment of DERs, for residential and commercial buildings
- **Energy Efficiency Revolving Loan Fund Capitalization Grants** to fund states to provide loans and grants for energy efficiency, upgrades, and retrofits, including distributed solar
- **Residential and Commercial Workforce Training Programs** that include training on smart tech and grid network systems
- **Community Power Accelerator** to provide training, resources, and technical assistance to developers

and organizations and connect them to investors, lenders, and philanthropies to finance and deploy solar and storage projects in communities across the country

- **National Community Solar Partnership** to expand access to affordable community solar; expanded program provides technical and financial assistance for developers interested in hosting or participating in a VPP from DOE National Labs
- **Clean Cities and Communities** to deploy affordable, efficient, and clean transportation fuels and energy efficient mobility systems, including EVs and EV charging
- **SolSmart** to provide no-cost technical assistance to local governments to make it easier for residents and businesses to go solar in their community
- **Charging Smart** to equitably expand electric vehicles (EVs) and EV charging infrastructure in rural, urban, and suburban communities by reducing soft costs (i.e., permitting, inspection, and load service requests)
- **Distributed Wind Smart** to develop and share best practices in zoning, planning, inspection, community engagement, and financing for distributed wind
- **Renewables Advancing Community Energy Resilience (RACER) Funding** to fund projects that enable communities to use solar and solar-plus-storage to prevent disruptions in power and rapidly restore electricity if needed
- **SolarAPP+** to automate and expedite permitting for residential rooftop PV and PV plus energy storage systems for solar contractors

Appendix B: Simplifying VPP enrollment

B.i. Case studies by lever

This section provides case studies of VPP and related deployments that showcase additional no-regrets and high-impact actions that are simplifying enrollment. One of these case studies, Arizona Public Service's Cool Rewards program, has a detailed overview provided in Appendix B.ii.

No-regrets actions

Lever	Example
Communicate program benefits in simple and concise terms *(especially financial benefits)*	Minnkota Power Cooperative's demand response program has **enrolled 55,000 customers (40% of customers) and can serve 350 MW, 35% of winter peak load,**[clxv] through the program.[clxvi] Minnkota is able to temporarily control DERs including heat pumps, water heaters, EV chargers, and commercial & industrial loads during peak events. To encourage enrollment and participation, Minnkota provides clear financial benefits – upfront incentives to purchase the DERs and eligibility for the off-peak program rate, which is roughly half the standard rate.[clxvii] Minnkota cultivated widespread buy-in from member distribution co-operatives to message the same.[clxviii,clxix]
Offer ongoing performance-based incentives to encourage continued participation	California's Demand Side Grid Support (DSGS) program **has enrolled over 265,000 participants with 515 MW of capacity in two years.** Customers can enroll by submitting an application to their DSGS provider.[clxx] The program is managed by Olivine which includes a 200 MW storage VPP, one of the largest in the world, to provide power back to the grid. Participants are paid based on net load reductions provided, with some earning $2/kWh of energy shared with the grid. The VPP was activated 16 times in 2024 to avoid a grid crisis during four heatwaves in the summer.[clxxi]
Offer a compelling value proposition to customers, with minimal additional effort on their part	One major Southern California utility partners with a program administrator to **deploy backup generation, solar, and battery storage assets with a 94% enrollment rate sustained over four years**. The program targeted communities that experienced the highest level of power outages and Public Safety Power Shutoff (PSPS) events on specific circuits and transmission lines. Deployment services included customer outreach campaigns by mail, email, telephone, and in-person to conduct in-home consultations to encourage eligible customers to apply and enroll in the program. Households were provided the assets for free, and the program administrator partnered with a local group of vendors to support the full customer lifecycle from first call to site visit and installation through five years of preventive maintenance and service.[96] As a continuation of this program, the utility instituted a VPP pilot program to use these resources (including smart thermostats, well-pump controllers, and water heaters) to shed load during peak hours.
Offer flexibility to opt out of events	Rocky Mountain Power's Cool Keeper program has enrolled **over 100,000 customers (~8.3% of customers, 280 MW of flexible load),**[clxxii] **with more than 98% of program participants satisfied with the program.** The program allows participants to opt out of events and un-enroll at any time at no additional cost by calling a phone number specific to the program.[clxxiii] Easy opt-out mechanisms put customers at ease when enrolling for programs and ensures appropriate customer protections are in place.
Leverage a multi-channel marketing approach	Ontario's Independent Electricity System Operator's (IESO) Save on Energy Peak Perks Program **has enrolled over 125,000 devices with over 100 MW of peak load reduction in less than one year.** The program leveraged a multi-channel marketing approach, including in-app messages by partnering with OEMs to get extra program visibility beyond standard in-app marketing, emails, and microsites. IESO worked with a marketing agency to spread the word through influencers and social media to enroll customers.[clxxiv] In 2024, the program delivered a maximum load shed of 133 MW during its first event.

96 Another example is SMUD who leveraged higher customer incentives to encourage participation in their Partner+ program. These incentives are meant to compensate customers for mandatory participation in the year-round use of their solar and storage systems.

High-impact actions

Lever	Example
Minimize customer time and effort to enroll in programs	EnergyHub, an edge DERMS provider with more than 1.3 million devices under management, **saw a 70% increase in "Enroll" button clicks on average by redesigning their utility microsite navigation and eliminating six clicks** from the path to enrollment. This increased accepted devices per month by over 1,000 across the programs that used the new template.[clxxv]
Offer point-of-purchase enrollment	APS launched Cool Rewards, a smart thermostat program, in 2018 after the Arizona Corporation Commission authorized demand response and load management programs for the utility. As of November 2024, the Cool Rewards program has enrolled over 97,500 connected thermostats with the ability to shed over 160 MW of load during peak demand events. **APS established a smart thermostat marketplace on their website** where *all* customers could get an instant $30 rebate at checkout and an additional $85 off upfront by pre-enrolling into the program.[clxxvi] As of the end of October 2024, 9,290 Cool Rewards pre-enrollments were processed through APS marketplace. Embedding enrollment into the point-of-sale process reduces marketing and recruiting costs for the program. *Detailed case study provided in Appendix B.ii.*
Enroll customers in multiple programs at once	AES Indiana partnered with Uplight Plus to pilot a subscription energy bundle by offering budget billing, digital payments, and green energy enrollment *all in one package*. Within the first three months of launching Uplight Plus with a pilot population of 2,000 residential customers, **AES Indiana saw a 26% increase in autopay enrollment and a 67% increase in green energy program enrollment**.[clxxvii]
Allow customers to set control ranges	Maryland utility Baltimore Gas & Electric partnered with WeaveGrid, a managed EV charging provider, to pilot a distribution-level charging program with over 3,000 residential customers. **WeaveGrid prioritizes optimizing EV charging for customers based on who has the lowest state of charge and who has the earliest departure time to maximize customer satisfaction.** 92% of charging load managed through the program complied with the charging schedule set by BGE and WeaveGrid, optimizing benefits for customers and the grid. The Maryland PSC approved BGE's proposal to expand the pilot to a full program with 30,000 participants by 2027.[clxxviii]

B.ii. Detailed case studies

Detailed case study #1: Arizona Public Service's Cool Rewards Program

Clear incentives and simple messaging allow APS to shed up to 160 MW of load (~2% of peak demand) by enrolling 97,500+ thermostats in the Cool Rewards program.

VPP summary			
Utility	Arizona Public Service	**VPP size** *(as of 2024)*	160 MW (2% of system peak)
Utility type	Investor-owned utility	**Type of DERs**	Smart thermostat
Market structure	Not in organized market, utility owns generation	**Upfront investment cost**	*Not available*
Location	Arizona	**Time to operationalize**	12 months
Size of utility	1.4 million customers (8.2 GW system peak)[clxxix]	**Number of customers enrolled in VPP**	72,000 (5%)
Compensation structure	» Upfront incentive: $50 one-time enrollment credit and $30 credit towards the purchase of a smart thermostat » Performance incentive: $35 annual participation credit		
Grid services	» Peak shaving, load shifting, location-based demand response		

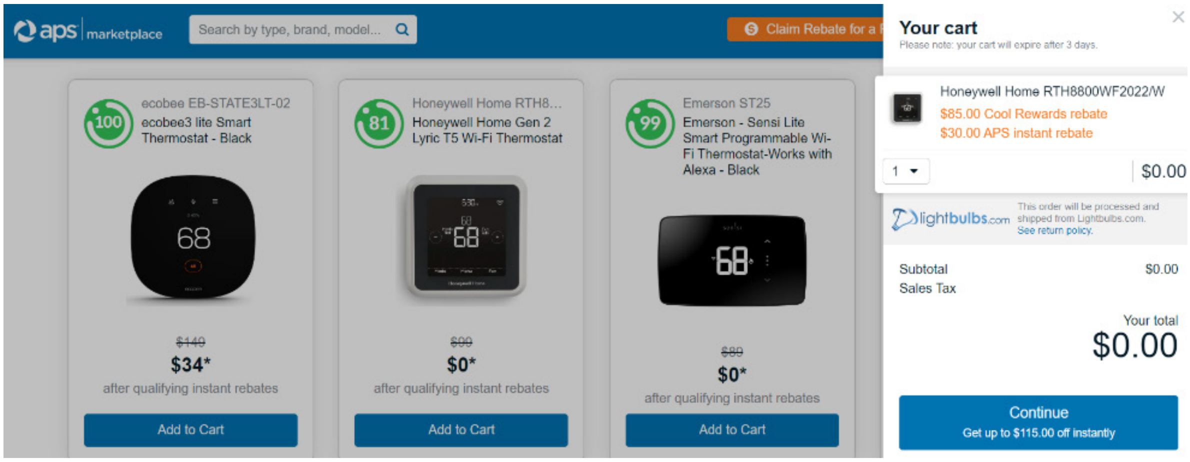
Utility objectives with VPP program (not exhaustive)

- **Reduce customer costs during times of peak demand** to ensure affordability of energy bills, especially given time-of-use rates[clxxx]
- **Decarbonize power supply** by achieving a resource mix that is 65% clean energy by 2030 by maximizing demand-side resource potential[clxxxi]
- **Maximize potential of demand-side resources** by meeting 19% of coincident peak demand by 2038 through optimizing energy efficiency, distributed resources, and demand response programs

Program summary

APS launched a smart thermostat program in 2018 after the Arizona Corporation Commission authorized demand response and load management programs for the utility. The Cool Rewards program is at the forefront of APS' VPP portfolio[97], incorporating smart thermostats for both residential and small to medium-sized business customers. As of November 2024, the utility had enrolled over 97,500 connected thermostats with the ability to shed over 160 MW of load during peak demand events.

97 APS' Cool Rewards program is one part of a broader VPP portfolio (193 MW as of November 2024) that mainly consists of smart thermostats, battery storage, and behavioral demand response, all working together to support the grid.



APS simplified the enrollment and participation process to maximize value from the demand response program, while minimizing customer inconvenience. APS established a smart thermostat marketplace on their website where all customers could get an instant $30 rebate at check-out.[clxxxii] With simple and clear messaging, APS allowed customers to receive an additional $85 off upfront by pre-enrolling into the Cool Rewards program after providing basic information (e.g., name and address).[98] Embedding enrollment into the point-of-sale process reduces marketing and recruiting costs for the program. As of the end of October 2024, 9,290 Cool Rewards pre-enrollments were processed through APS marketplace, which was built in partnership with Enervee.[clxxxiii]

APS offers virtual assistance for customers needing support with installing their smart thermostat after purchase. For those unable to install virtually, in-home installation support is also available. These partnerships help ensure thermostats are properly installed, connected, and ready for use, enhancing customer value.

APS ensures ongoing participation by prioritizing customer comfort, allowing flexible opt-outs, offering ongoing incentives, and communicating social impacts of participation. To ensure customer comfort, some thermostat manufacturers may lower a customer's thermostat(s) temperature a few degrees to pre-cool the home before the peak event, increase the thermostat by a couple of degrees during a conservation event, and return the thermostat to its original setting or schedule after the event.

Customers can easily opt out of events by directly changing the thermostat setting. In 2023, APS launched the Cool Rewards Promise which reinforces that the customer will always remain in control of their thermostat and can adjust or opt-out at any time. APS provides annual participation incentives, which APS increased from $25 to $35 per year after receiving customer input and has seen a corresponding increase in enrollment. APS also communicates the social impacts of the program by sending messages such as, "This summer, your participation made a positive difference for our environment and community" to encourage continued participation.

Key success factors to simplify VPP enrollment *(not exhaustive)*

- ✔ **Capture customers at point of purchase by establishing an online marketplace,** clearly communicating financial benefits to purchase a smart thermostat ($30 instant rebate) and additional upfront incentives to pre-enroll in the Cool Rewards program ($85 enrollment credit and first year participation credit)
- ✔ **Provide installation support** to help customers easily connect their smart thermostat
- ✔ **Launch the Cool Rewards Promise** to remind customers of the event's purpose, ensuring they remain in control of their device
- ✔ **Communicate social impacts** to keep customers engaged in the program after enrollment

98 Uplight, a flexibility management platform, found that over 60% of eligible customers purchasing a smart thermostat through their marketplace enrolled in demand response programs when offered at point of sale.

B.iii. Key resources for practitioners

- **Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment** (December 2024, Lawrence Berkeley National Lab) discusses 30 proven strategies to scale VPPs by maximizing enrollment with concrete case studies and proof points.
- **Insights into Scaling Virtual Power Plants** (January 2025, Lawrence Berkeley National Lab) provides a publicly available inventory of VPPs in the U.S.
- **North America Virtual Power Plant (VPP) Market Report** (July 2024, Wood Mackenzie) provides an overview of the state of the VPP market today in the U.S. and Canada, including technology trends, VPP offtake, and wholesale market and regulatory landscape.
- **VPP Flipbook** (July 2024, RMI and VP3) includes discussion of 22 VPP programs in operation across the U.S., including details on effective VPP program design and implementation.
- **Utility VPP Comparison Matrix** (June 2024, RMI) shares program design information for 22 VPP programs featured in the RMI VP3 Flipbook.
- **National Roadmap for Grid-Interactive Efficient Buildings** (May 2021, DOE) includes an overview of grid-interactive efficient buildings (GEB), and the barriers and solutions to accelerating GEB deployment across the country.

B.iv. Actions from the Department of Energy

- **V2X MOU** to establish partnership and business case demonstration projects that identify interconnection standards, market access needs, and interoperability approaches for EV charging and discharging with public and private sector engagement
- **Computational tools**[99] developed and applied by National Laboratories to help regulators and utilities determine how to apply DERs, including microgrids, to better serve equity and resilience needs

99 Page 69 of the 2023 VPP Liftoff Report includes detailed information on the modeling tools available from select DOE-partnered national laboratories.

Appendix C: Increasing standardization in VPP operations

This section provides an explanation of the communication protocols and IT/OT components and configurations for three VPP programs: National Grid's 'ConnectedSolutions' in Massachusetts and New York, Green Mountain Power's 'Energy Storage Solutions' in Vermont, and Rocky Mountain Power's 'Wattsmart' in Utah. The purpose of the case studies is to demystify the communication technology that enables a VPP and help stakeholders understand where increased standardization will be valuable – e.g., interoperability of DER and VPP software, grid services definitions, etc.

To reference the framework that shares the possible go-to-market models, see page 23 of this report in Section 3.i.

Go-to-market model:	**① Utility-led, aggregator-operated VPP**	**①③ Utility-run VPP and market-participant VPP**	**③ Utility-run VPP**
Case study:	**ConnectedSolutions**	**Energy Storage System**	**Wattsmart**
Bulk system operators	**ISO New England**	GREEN MOUNTAIN POWER	ROCKY MOUNTAIN POWER
Distribution system operators	**National Grid**	GREEN MOUNTAIN POWER	ROCKY MOUNTAIN POWER
VPP platforms	EnergyHub	TESLA	sonnen
Customer DERs (residential, commercial, industrial)	• 10 Smart thermostat brands • 17 Battery brands • 19 EV and EV supply equipment brands • 7+ Commercial & industrial aggregators	ESS program: • Tesla Powerwalls or equivalent compatible equipment	• Any battery that meets functional criteria, including sonnen. • Four additional battery manufacturers under testing and review.

C.i. Detailed case study #1: ConnectedSolutions

VPP overview

National Grid's ConnectedSolutions Program

Multi-device VPP established within 4 months with <$500k upfront investment cost provides up to 250 MW of system-level peak shaving benefits.

VPP summary			
Utility	National Grid	**VPP size** *(as of 2024)*	250 MW (2% of system peak)
Utility type	Investor-owned utility	**Type of DERs**	Residential DERs: Smart thermostats, batteries. Commercial DERs: HVAC, manufacturing loads, bidirectional EV chargers, water heaters, thermal storage, batteries.
Market structure	Within organized market (ISO-NE and NYISO), utility does not own generation	**Upfront investment cost**	$500k
Location	Massachusetts and New York	**Time to operationalize**	4 months
Size of utility	20 million customers (11.5 GW peak demand)	**Number of customers enrolled in VPP**	100,000
Compensation structure	Residential: » Thermostats: $25 – $50 upfront incentive per thermostat; additional $20 incentive for staying enrolled. » Batteries: 0% Interest 7-Year Loan for battery costs; $275/kW performance incentive. Commercial: » $30 - $200/kW performance incentives depending on the location and number of dispatches per year.		
Grid services	» Electric and natural gas peak shaving, non-wires alternatives		

Utility objectives with VPP program *(not exhaustive)*

- **Meet rising demand** by delivering bulk system-level capacity during peak hours.
- **Reduce cost** by pursuing all cost-effective demand reduction measures[100,clxxxiv] to reduce customer energy bills.
- **Alleviate grid constraints** by using flexible demand as non-wires alternatives to address grid congestion or load limits of grid equipment.

100 The 2016 State of Charge: A Comprehensive Study of Energy Storage in Massachusetts Report found that 40% of each year's electric costs were due to the 10% of hours with the highest electricity demand.

Program summary

National Grid developed and launched its ConnectedSolutions 'bring-your-own-device' (BYOD) VPP in less than four months to provide low-cost, low-emissions peaking capacity in Massachusetts and New York.[101] The program launched fully in 2019. In this configuration, National Grid contracts with EnergyHub, an Edge DERMS vendor that integrates multiple single-brand VPP software systems (e.g., Tesla) into one platform. National Grid sends notices to EnergyHub in advance of peak hours to dispatch demand reductions from the customer-owned DER aggregation that EnergyHub manages on National Grid's behalf. By relying on EnergyHub to manage the customer enrollment and participation experience, and to turn the heterogeneous portfolio of DERs into a utility-scale and utility-grade resource, National Grid required little change to its internal organizational operations.

Delivered outcomes

- ✔ **Reduced costs of peak demand,** providing an estimated $300M in system benefits since the start of all of National Grid's demand response programs by reducing the buildout of power plants, the grid, and reducing energy use at expensive peak times.
- ✔ **Met regulator goals** by earning financial profit for National Grid (specific incentive mechanisms vary by state).
- ✔ **Reduced cost of ownership of DERs** by compensating them for grid benefits delivered.

VPP communication protocols & operations

National Grid works with EnergyHub to operate ConnectedSolutions in the following ways:

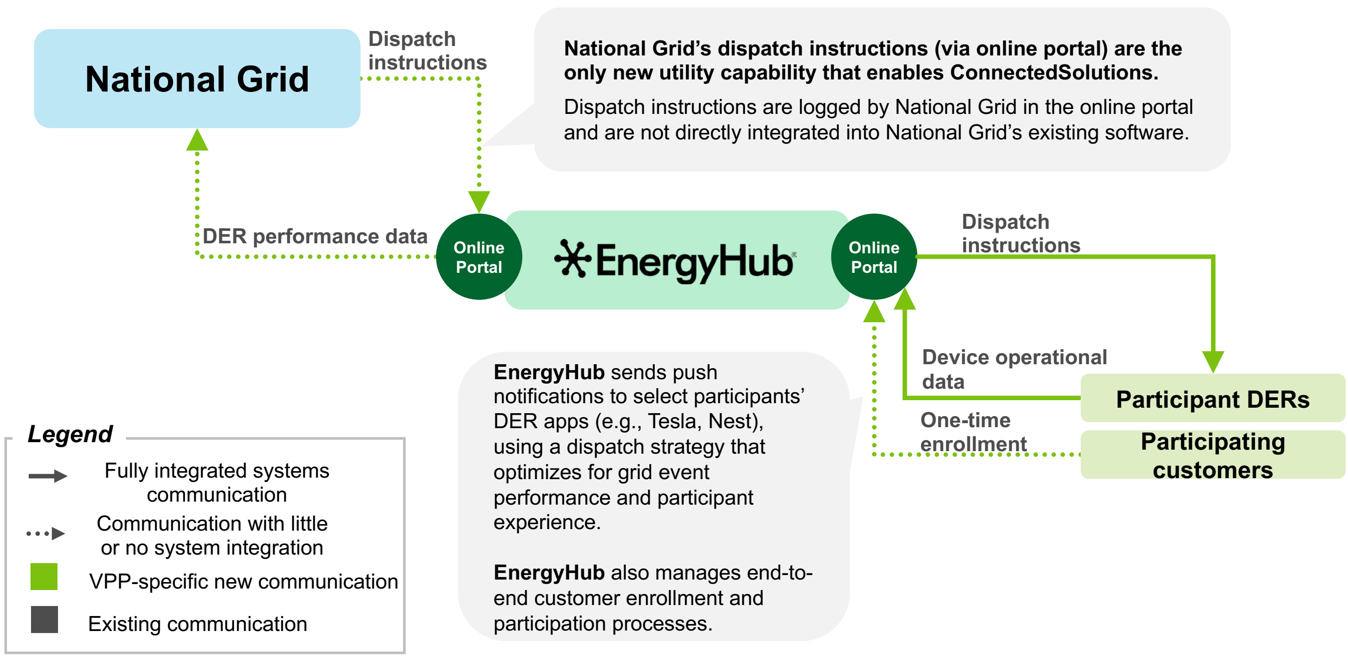
1. National Grid or EnergyHub (depending on the jurisdiction) estimates peak demand and establishes the level at which grid events will be called.
2. National Grid or EnergyHub (depending on the jurisdiction) tees up and then triggers demand response events when loads on the grid are forecasted to exceed the established levels.
3. EnergyHub communicates the demand response event parameters to various DER device manufacturers and providers, curtailment service providers and aggregators. The communication happens through a variety of open protocols and proprietary APIs. Depending on how much grid relief is needed, dispatch happens in three levels:
    a. The first level call is to maximize demand reduction by discharging residential-scale and commercial-scale batteries. Batteries are called on approximately 50 times per summer.
    b. The second level adds (in addition to the first) in HVAC load reduction through smart thermostats to optimize for customer comfort and maximize continued participation in events.[102] HVAC is called on approximately 15 times per summer.
    c. The third level adds (in addition to the first and second) commercial & industrial load reduction. This is a last resort given load size and potential costs of, for example, shutting down an entire assembly line. These assets are called on approximately 5 times per summer.
4. EnergyHub receives DER energy consumption data and meter data through a variety of open protocols and proprietary API connections with DER manufacturers, providers, curtailment service providers, and aggregators.

101 For additional detail on the policy and regulatory context in which ConnectedSolutions was implemented, including the energy and non-energy benefits included in the cost-effectiveness test for the program, see the case study annex (page 66) of [NARUC's ADER Resources in 2024: The Fundamentals](#).

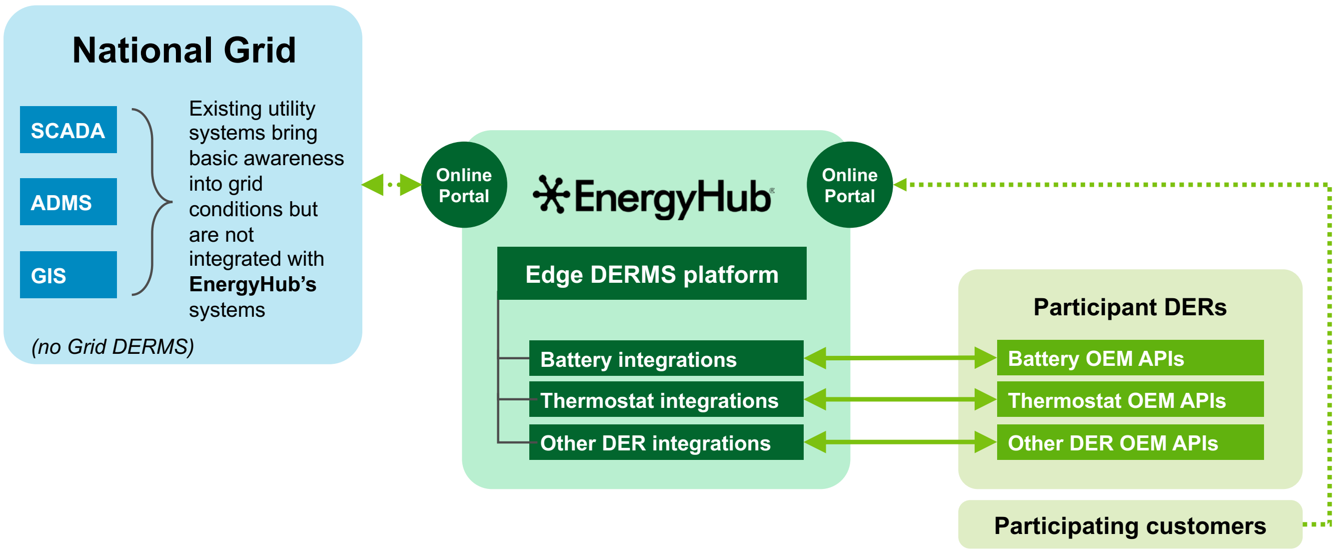
102 Customers can opt out of an event by re-adjusting their smart thermostats.

5. EnergyHub uses the DER telemetry to calculate the performance for each DER and end each event.
6. EnergyHub shares performance data with 15-minute telemetry to National Grid.[103]

VPP communications



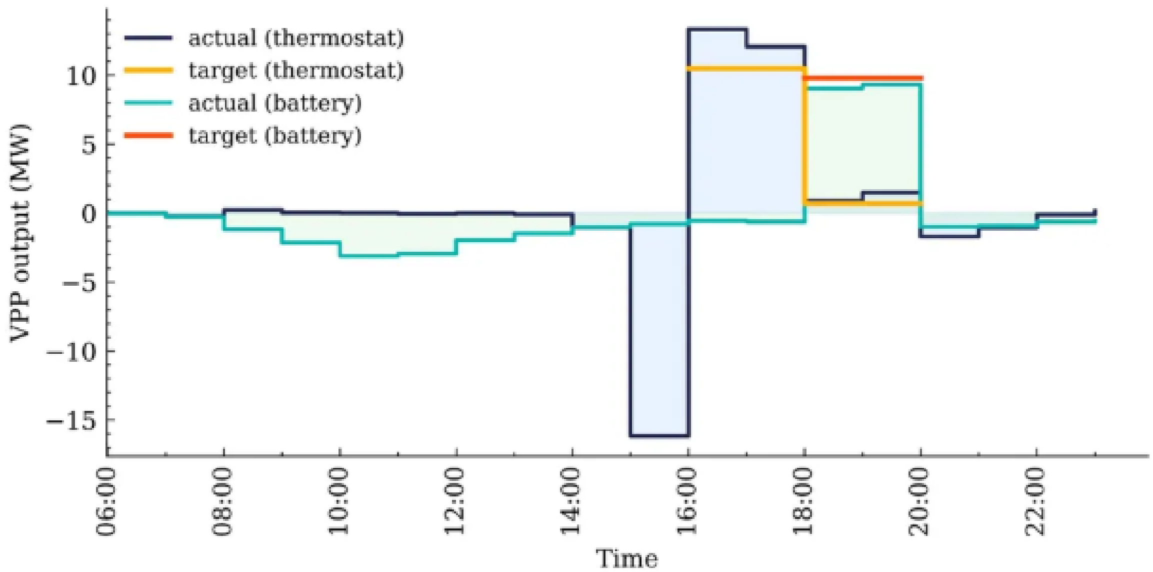
IT and OT components



103 For devices that are not equipped to provide minutely telemetry, EnergyHub conducts modeling to estimate what the capacity would be from those resources on a minute-by-minute basis and provides that to National Grid.

Delivered outcomes

The chart below shows the MW output of the thermostats and batteries enrolled in ConnectedSolutions during a four-hour peak reduction event. As the chart shows, thermostats adjust to pre-cool buildings and homes from 3pm to 4pm, then reduce air conditioning load at 4pm when the event begins. After two hours, thermostats return to normal operations and batteries dispatch to deliver the second two hours of reduced load on the grid.[clxxxv]



Source: EnergyHub

C.ii. Detailed case study #2: Energy Storage System (ESS) Leasing Program

VPP overview

Green Mountain Power's Energy Storage System Leasing Program

Utility-owned and operated battery VPP offers backup power for participants, peaking capacity, emissions reduction, and transmission benefits for the grid, and lower costs for all customers.

VPP summary			
Utility	Green Mountain Power	**VPP size** *(as of 2024)*	36 MW (5% of system peak)
Utility type	Certified B Corp, Investor-owned utility	**Type of DERs**	BTM battery
Market structure	Within organized market (ISO-NE), utility owns generation	**Upfront investment cost**	*Not available*
Location	Vermont	**Time to operationalize**	12-24 months
Size of utility	275,000 customers (663 MW peak demand)	**Number of customers enrolled in VPP**	4,800 customers
Compensation structure	» GMP maintains ownership of batteries and leases them to customers for a 10-year period, either for a one-time payment of $5500 or a $55 monthly fee. Customer continues to get battery backup at no cost after 10 years. » In return, customers are equipped with backup power during outages for a significantly lower price than they would have paid for a non-enrolled battery.		
Grid services	» Peak shaving, frequency regulation		

Utility objectives with VPP program *(not exhaustive)*

- **Reduce costs for all customers** by decreasing GMP's capacity obligation in ISO-New England and GMP's service territory transmission charges, and reducing demand during peak hours. Achieve additional cost savings through energy arbitrage (discharging batteries during peak hours and recharging during off-peak when prices are lower).
- **Improve resilience** by offering seamless backup power for participants to keep customers connected during increasingly severe weather and other events.

Program summary

Green Mountain Power fully launched the Energy Storage System Leasing (ESS) program in 2020, after two successful pilots, to improve system reliability in the face of extreme weather while reducing costs for all customers.[104] GMP operates the program with Tesla technology. Tesla supplies the battery hardware (Powerwalls) and acts as the software platform that aggregates and orchestrates battery dispatch. GMP sends real-time load data (generated by metering integrated with their SCADA system)[105] to Tesla via an API to communicate demands on the distribution grid. Tesla uses that information to strategically dispatch batteries to shave peaks on the distribution system. The program is open to additional battery systems as well and GMP continues to test the latest available battery technology to integrate into the program.

GMP's ESS program is continuously evolving to produce more value. Initially, the utility used the batteries for peak shaving and back up power, but then piloted and now tariffed the use of the same batteries for frequency response, which it sells into the ISO-NE market to generate revenue it can use to directly reduce costs for all GMP customers. Future goals of the program include:

- **Additional grid services:** GMP is working to identify opportunities to use the batteries in targeted locations to alleviate grid constraints at the substation level, which would allow deferrals of costly equipment upgrades.
- **Integration with other resources:** GMP separately operates a bring-your-own-device VPP using a Virtual Peaker platform, as well as a commercial flexible load program using the platform of a Vermont-based software company, Dynamic Organics. The utility is also collaborating with customers to create benefits with other distributed resources such as smart EV chargers.
- **Automation:** With experience and historical data, GMP will be able to automate how a VPP reacts to grid conditions and external conditions (e.g., distributed solar output and weather).

Delivered outcomes

- ✔ **Reduced costs for all customers** by reducing Green Mountain Power's capacity obligation in ISO-New England forward capacity auction by 36+ MW per year (reducing system costs by as much as $3M in some years for all customers – both participants and non-participants).
- ✔ **Generated revenue** of $250,000 from frequency regulation to return to customers.
- ✔ **Improved customer resilience** by enrolling over 4,800 customers in the ESS program, equipping each with backup power to stay connected during extreme weather and other events.

104 For additional detail on the policy and regulatory context in which GMP implemented its VPP, including the monetized and non-monetized benefits of the program, see the case study annex (page 63) of NARUC's ADER Resources in 2024: The Fundamentals.

105 Supervisory control and data acquisition systems (SCADA) are a collection of systems used to monitor, report on, and remotely operate grid equipment.

VPP communication protocols & operations

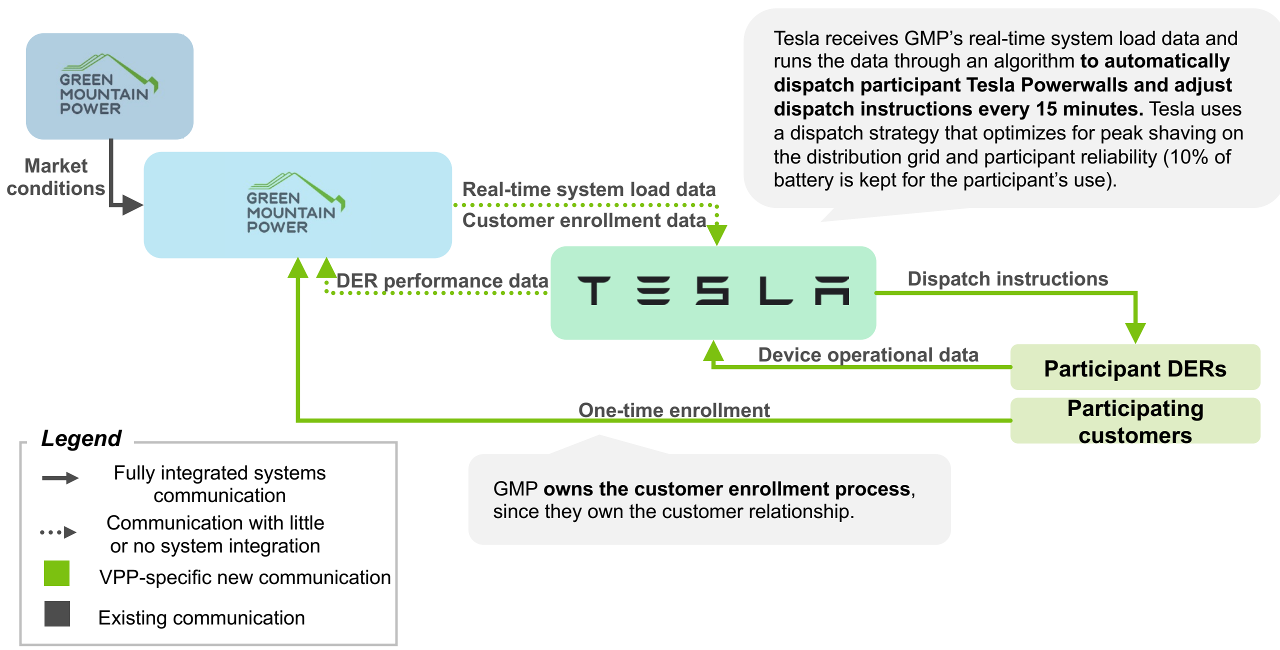
Green Mountain Power works with Tesla to operate ESS in the following way:

1. GMP provides real-time system load data from their SCADA system to Tesla through an API connection.
2. Tesla receives the load data and uses its own algorithm to determine optimal usage of Tesla Powerwalls across the distribution grid, primarily for peak shaving.
3. Tesla manages the Powerwalls through direct integration, adjusting usage of batteries every 15 minutes (or in the case of frequency regulation every four seconds) to respond to system conditions.[106]
4. Tesla receives real-time performance data of batteries and pushes data through the API to GMP in real-time.

Additionally, Green Mountain Power completed a successful pilot and has now tariffed a program to bid their fleet of Tesla batteries into ISO-NE for fast frequency response services (ancillary services market), using the same technology architecture *(excluded from communications protocols and IT / OT components diagrams)*:

5. Tesla receives real-time market signals and pricing information through an API connection with ISO-NE.[107]
6. Tesla's updated algorithm manages GMP's batteries to optimize for load, while bidding into ISO-NE for fast frequency response services, adjusting usage of batteries every four seconds.[108]

VPP communications

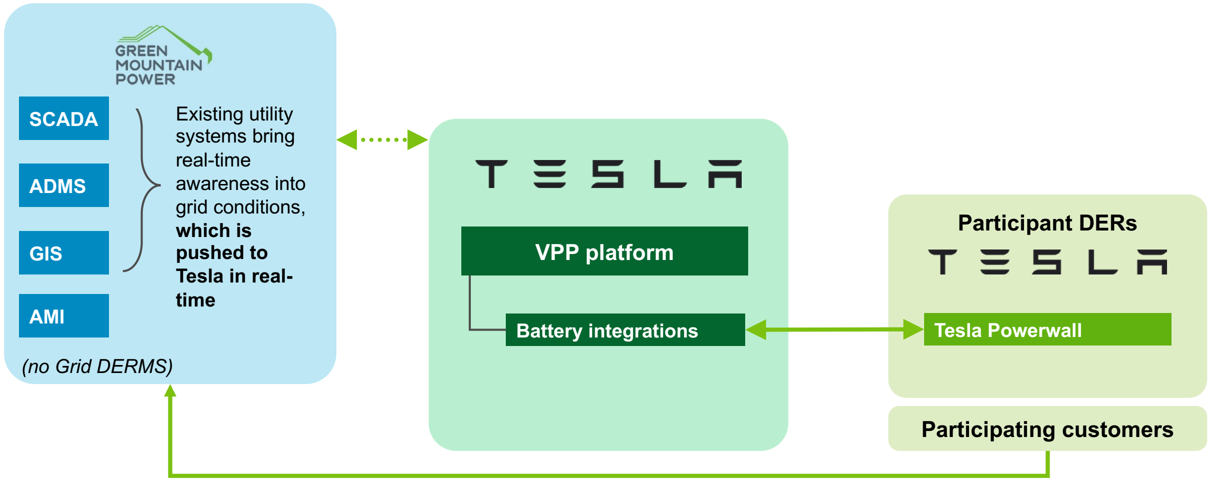


106 Tesla's algorithm continuously monitors Vermont and ISO-NE load and dispatches the batteries accordingly to maximize peak shaving. Customer backup is always prioritized, however, which means weather events override peak shaving.

107 GMP provides the bids for frequency regulation on a weekly basis (i.e., hour-by-hour MW availability for the week) to a third-party who bids them into ISO-NE. During hours the batteries clear the market and are performing regulation, Tesla receives the signals every four seconds from ISO-NE via API and adjusts the batteries charge / discharge to match the signal.

108 The response time for data communicated from GMP to the battery (over the internet), then to the market (also over the internet) is two seconds.

IT and OT Components



C.iii. Detailed case study #3: Wattsmart

VPP overview

Rocky Mountain Power's Wattsmart

Battery VPP that integrates directly into utility's grid operations system enables many grid services.

VPP summary			
Utility	Rocky Mountain Power	**VPP size** *(as of November 2024)*	28 MW (0.5% of system peak)
Utility type	Investor-owned utility	**Type of DERs**	BTM battery
Market structure	Not in organized market, utility owns generation	**Upfront investment cost**	$5 million
Location	Utah	**Time to operationalize**	3 years
Size of utility	1.2 million customers (5.58 GW peak demand)	**Number of customers enrolled in VPP**	4,200
Compensation structure	» Upfront cash enrollment incentive based on battery capacity available for discharge. As of 2023, up to $600 per kW, with the highest incentive offered to customers who are "firming" existing distributed solar. » Ongoing participation incentive in the form of an annual bill credit of $15 per kW, starting in the second year of participation.		
Grid services	» Fast frequency response, daily load cycling		

Utility objectives with VPP program (not exhaustive)

- **Keep costs low** (some of the lowest energy prices in the nation) by procuring bulk grid and distribution grid services including energy, capacity, and fast frequency response to cost-effectively transition to a decarbonized power supply.
- **Improve resilience** and reduce severity of weather-related outages by providing backup power from BTM batteries to customers.
- **Decarbonize power supply** by maximizing usage of cheap solar and reduce reliance on peaker plants by charging batteries during the day and discharging batteries during peak periods (supporting decarbonization goals of cutting greenhouse gas emissions by 70% by 2030 and 100% by 2050[clxxxvi]).

Program summary

Rocky Mountain Power developed its Wattsmart battery VPP to deliver high-value grid services cost-effectively and increase battery adoption among customers. By obtaining a "full stack" of valuable grid services from the batteries, RMP creates significant value for the grid and in turn pays participants both an upfront and an ongoing performance incentive that helps offset the purchase price of the battery. Wattsmart is among the most advanced VPPs in the U.S. due to its degree of integration into the utility's overall system operations and the wide array of uses (grid services) of the battery aggregation. Unlike VPPs used only during peak hours or peak seasons (summer, winter), RMP may use its batteries 365 days of the year, 24 hours per day.

RMP directly dispatches the batteries using a distributed battery grid management system (DGBMS) that integrates into the utility's energy management system without any intermediate layer of an edge-DERMS.

The network of batteries can respond to dispatch signals in as little as three seconds (sonnen and Core+ batteries) and no slower than 50 seconds (other brands). The system is programmed to dispatch targeted clusters of batteries daily to support peak periods and as needed in response to real-time grid conditions and solar output, which are monitored and communicated via RMP's Energy Management System. The VPP delivers eight grid services:

- System-level demand response and peak shaving
- Firm dispatchable capacity for system requirements
- Storage of renewable energy for dispatch to meet grid load requirements
- Secondary frequency response to load and inject power to rebalance system frequency
- Daily load cycling to charge batteries during low-cost off-peak periods and discharge batteries during peak hours
- Backup power for resiliency
- Non-wires alternative for local load pocket decongestion
- Spinning and non-spinning reserve capacity to provide emergency stabilization power

RMP worked closely with battery manufacturer and software provider sonnen to ensure the battery chemistries and controls would allow for multiple battery dispatches per day in addition to a high degree of visibility and control.[109] The Wattsmart VPP is growing rapidly, with a near-term goal of reaching 100 MW by recruiting customers with solar arrays (>80,000 in Utah) and offering battery incentives to motivate customers to 'firm' their renewable power.

109 Sonnen underwent rigorous certification and testing to ensure the program met all necessary cybersecurity requirements.

Delivered outcomes

- **Reduced costs for all customers** by storing excess renewable energy during low-cost off-peak periods (<3 cents kWh) and dispatches that energy during high-cost peak periods (costs as much as 10x more) to reduce system peaks.
- **Improved customer resilience without raising rates,** enrolling over 5,000 customers in the program and equipping each with backup power.
- **Achieved high usage for real-time system needs** by calling 153 real-time frequency response events from October 2023-November 2024.
- **Developed standards for battery manufacturers** by establishing a clear roadmap for battery designs that ensures products are able to integrate with utilities systems.
- **Developed an open innovation platform** to continually improve based upon customer feedback and inclusion of new innovation.[110,clxxxvii]

See delivered outcomes section for visualizations of battery dispatch data for peak management operations and distribution circuit congestion event.

VPP communication protocols & operations

Rocky Mountain Power works with sonnen to operate WattSmart in the following way:

1. Rocky Mountain Power's grid operating team can view the real-time grid services available from sonnen's VPP within their existing SCADA system– the team does not need to log into any other system due to API integrations.
2. If services from Wattsmart batteries are required to manage the electric grid, the SCADA system will automatically send a signal to the VPP, or the grid operating team can select an option from their operations screen.
3. Sonnen's VPP software layer receives the dispatch signal in real-time and calls the necessary sonnen batteries and non-sonnen batteries to respond.
    a. Batteries typically respond within 5 seconds and no longer than 50 seconds.
    b. The batteries respond and use the same channels to send operational data back to sonnen's VPP.[111]
4. The VPP provides real-time operational data to Rocky Mountain Power sharing how batteries are performing with 2-3 second precision.
5. The VPP software layer, in combination with Wattsmart program qualified battery, is optimized for all eight primary grid services that benefits both customers and utilities.[clxxxviii]
6. Sonnen's VPP software layer receives the dispatch signal in real-time and calls the necessary sonnen batteries and non-sonnen batteries to respond.
    a. It calls sonnen's batteries through direct dispatch instructions and receives direct operational data from these batteries in real-time.
    b. It calls non-sonnen batteries by sending dispatch instructions using IEEE 2030.5 protocols to an IEEE 2030.5 compliant server in Germany and in the U.S. This server then sends dispatch instructions to the non-sonnen batteries using IEEE 2030.5 protocols, ensuring no concern of

110 For an in-depth, 20-page case study of the program benefits realized by Utah's Wattsmart Battery program across frequency regulation services, peak load management, congestion relief, and backup power, see '[Utah WattSmart Batteries Program: Grid Service Benefits Analysis](#).'

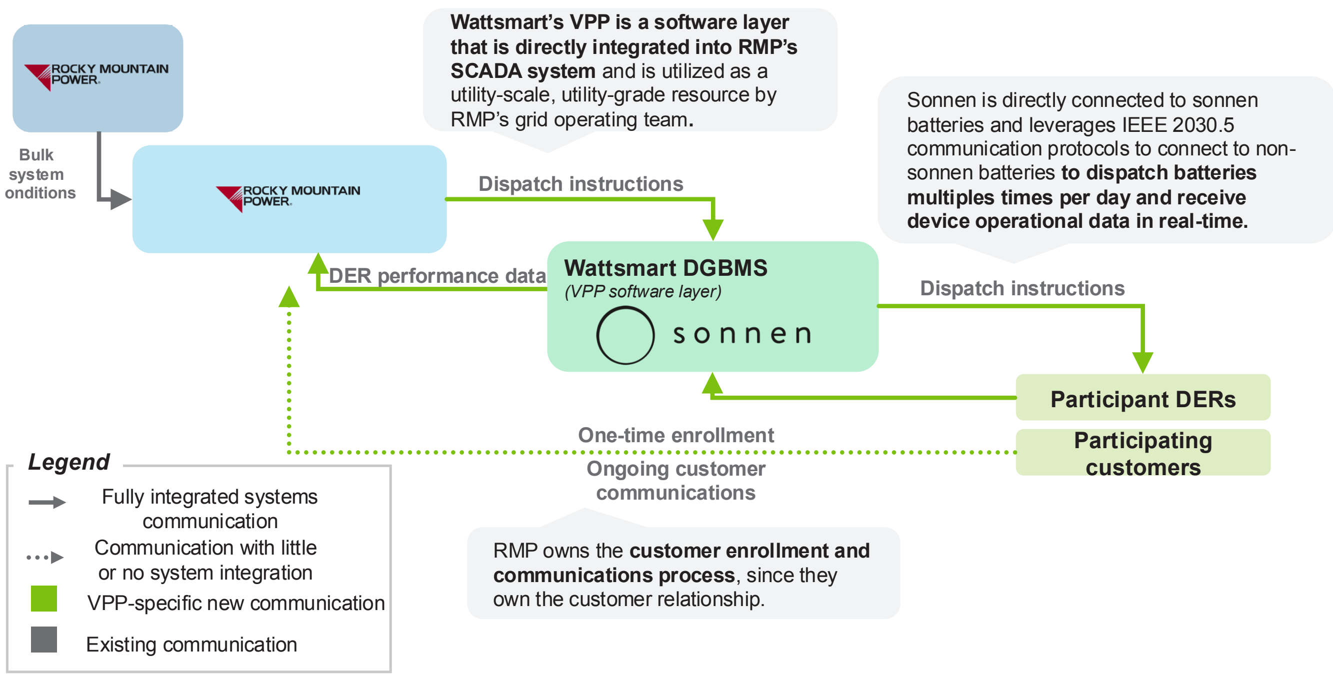
111 The Wattsmart Battery program requires participating batteries to be IEEE 2030.5 protocol compliant, ensuring no intellectual property exchange occurs while utilizing RMP's SCADA system and sonnen's VPP.

intellectual property exchange between battery manufacturers. The batteries respond and use the same channels to send operational data back to sonnen's VPP.

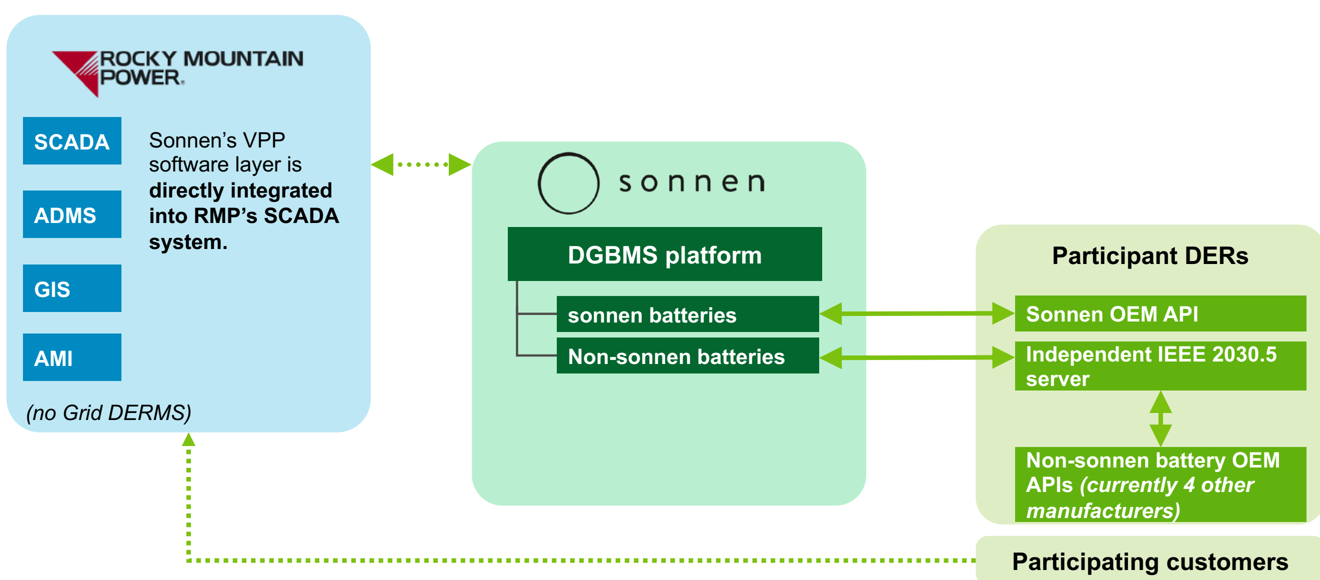
7. After dispatching necessary batteries, sonnen provides real-time operational data to Rocky Mountain Power sharing how batteries are performing with 2-3 second precision.[112]

8. In addition, sonnen's VPP software layer optimizes for daily load cycling, directing batteries to soak up solar when it is cheap during the day and discharge batteries during daily peak hours.

VPP communications



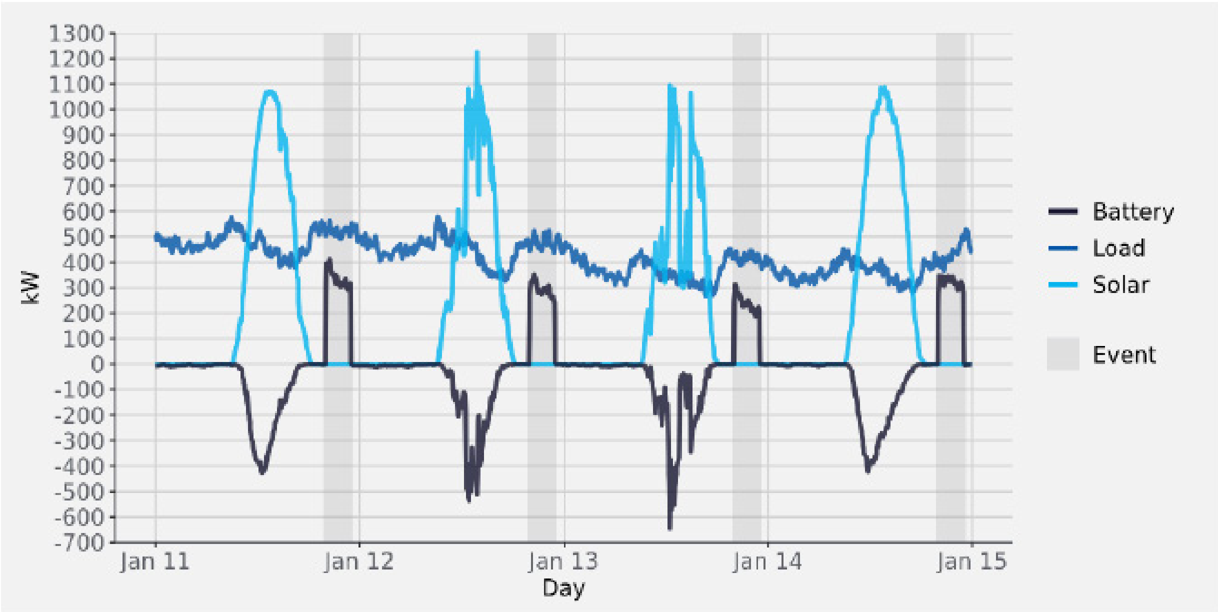
IT and OT components



112 Long term, this operational data helps RMP and sonnen understand the value and performance of the system to improve operations and inform proposed customer incentives.

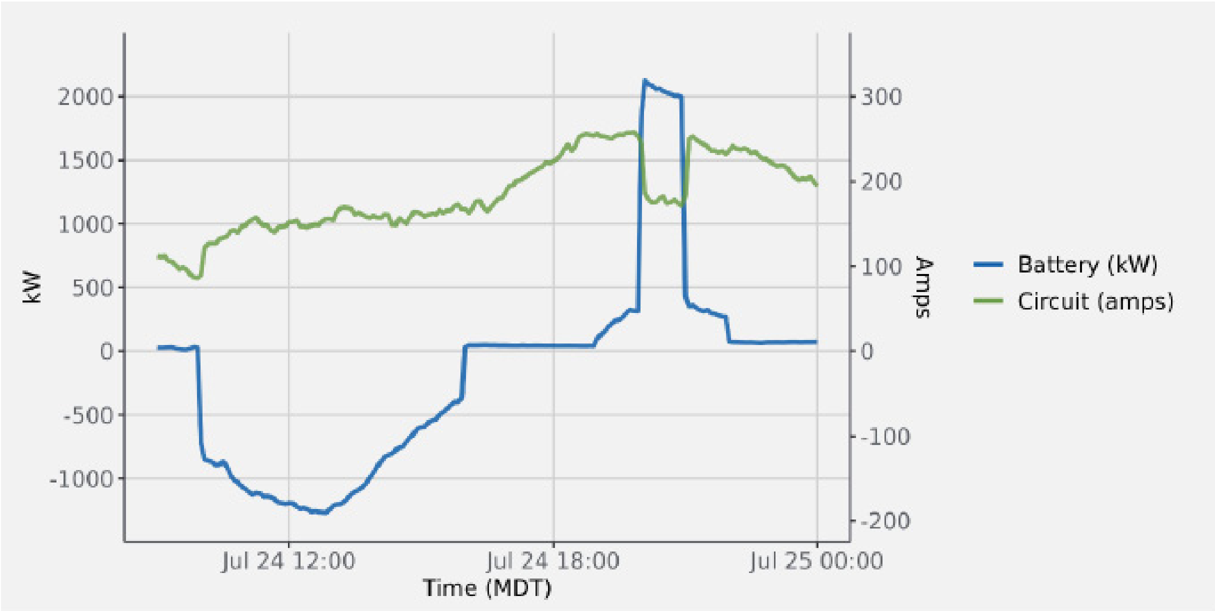
Delivered outcomes

Peak management operations: The chart below shows four days in January 2021 when RMP dispatched battery systems in the evening that had been charged with solar earlier in the day to reduce peak demand during evening peak hours of 8 pm to 11 pm (peak events are depicted by the darker gray bars).



Source: Rocky Mountain Power, Cadmus

Distribution circuit congestion event: The chart below shows the dispatch of battery systems to relieve congestion on a distribution circuit on July 24, 2021. Between 8-9pm, the Wattsmart battery systems were dispatched to reduce load at the circuit and relieve transmission congestion. In aggregate, the batteries delivered approximately 2 MW throughout the event hour during which time load at the circuit was reduced by 30%.



Source: Rocky Mountain Power, Cadmus

C.iv. Key resources for practitioners

- **Stakeholder Perspectives on the Role of Standards in Establishing a Load-Flexible Ecosystem** (August 2024, CalFlexHub) shares qualitative results of 52 stakeholder calls on the role of standards in California.
- **Cybersecurity Considerations for Distributed Energy Resources on the U.S. Electric Grid** (October 2022, DOE) provides an overview of cybersecurity considerations for DERs that can be considered by the electric sector.

C.v. Actions from the Department of Energy

- **Grid Solutions program**, a collection of tech programs, to define coordination and system requirements to enable the utilization of grid services from DERs and VPPs in collaboration with regulators and utilities
- **Distributed Resource Utilization** to support state organizations and utilities in standardizing processes between utilities and third-party DER aggregators, reducing barriers to implementation and enabling more effective operational coordination
- **Aggregator Standard Contract** to define how to govern aggregators using a standard contract for VPP and aggregator services to expedite the approval process while ensuring consumer protections
- **National EV Infrastructure Standards** to ensure federally-funded charging equipment is capable of smart charging
- **Building Energy Codes Program** to support development, adoption, implementation, and enforcement of codes to achieve energy efficiency
- **Distribution system cybersecurity baselines**, as part of the National Cybersecurity Strategy, led by NARUC and the Office of Cybersecurity, Energy Security, and Emergency Response at DOE, to develop a set of cybersecurity baselines for electric distribution systems and the DERs that connect to them
- **Distributed Energy Resource Cybersecurity Framework**, a no-cost interactive web tool, to evaluate a facility's DER cybersecurity health and provide recommendations
- **Cyber-Informed Engineering** to provide tools, case studies, and lessons to support designers, manufacturers, and asset owners in applying cyber-informed engineering principles
- **Energy Threat Analysis Center** to launch cybersecurity threat collaboration between industry and government to enable collective defense
- **VPP-related research, development, and deployment (RD&D) programs** focused on systems integration to address key technical challenges in power system planning and operations
- **EVs@Scale National Laboratory Consortium** to bring together national laboratories and key stakeholders to conduct research and development to address challenges and barriers for high-power EV charging infrastructure to enable greater safety, grid operation reliability, and consumer confidence
- **Connected Communities Program**, focusing on technical measures at the grid edge in buildings, industry, and transportation to prepare the electric grid for these new loads, and improve the resilience of customers and the grid

- **Grid Resilience Utility and Industry Grants** and **Smart Grid Grants**, which are part of the GRIP Program, to fund deployment of comprehensive transformational transmission and distribution technology to increase the flexibility, efficiency, and reliability of the electric power system and modernize the grid to reduce impacts due to extreme weather and natural disasters
- **Interconnection Innovation e-Xchange (i2X)** to provide technical assistance and engage stakeholders to improve interconnection practices and processes for electricity distribution and transmission systems
- **Sustainable and Holistic Integration of Energy Storage and Solar PV (SHINES)** to develop and demonstrate integrated PV and energy storage solutions that are scalable, secure, reliable, and cost-effective
- **Solar Technologies' Rapid Integration and Validation for Energy Systems (STRIVES)** to fund research, development, and demonstration projects to improve power systems simulation software tools and demonstrate new business models for distribution systems operations
- **Operation and Planning Tools for Inverter-Based Resource Management and Availability for Future Power Systems (OPTIMA)** to fund projects that will develop new state-of-the-art planning and operations tools for utilities and bulk system operators. These projects will help address challenges with integrating variable inverter-based renewable generation and distributed energy resources, as well as T&D coordination and co-optimization

Appendix D: Integrating into utility planning and incentives

D.i. Menu of VPP-supportive regulatory and policy options

This menu of options provides a range of choices for state and tribal regulators, policymakers, and utilities to explore alongside examples of regulators and policymakers that are implementing these strategies today. This list aims to capture the breadth of actions available to support VPP deployment but is not an exhaustive list. Two of these case studies, New York's Value of DER (VDER) Program and Massachusetts' Electric Sector Modernization Plans, have a detailed overview provided in Appendix D.ii.

Notes: These levers particularly apply to IOUs that are regulated at the state and federal level. Governing bodies of other utilities (e.g., member boards of co-ops, city councils overseeing public power, tribal utility authorities) can also look to these levers for consideration. These policy and regulatory levers identified are primarily focused on VPP related programs and are not exhaustive of the best practices and policy/regulatory levers to support grid modernization generally.

Utility cost recovery

Regulatory and policy options	Examples
• **Use performance-based ratemaking (PBR)**, performance incentive mechanisms, and / or multi-year rate plans • **Allow utilities to include DERs and VPP foundational infrastructure (e.g., DERMS) in rate base**[113]	**Massachusetts Department of Public Utilities (DPU)** has established a performance incentive mechanism for energy efficiency programs, which includes the ConnectedSolutions VPP program; the total incentive is significant with a total of $190M profit potential for all of MA's IOUs over the current 2025-2027 planning period if the goals are met. Utilities must meet at least 80% of efficiency goals to generate any profit, with a maximum profit of up to 125% over the goal.
	Vermont PUC issued an order in 2023 (Case No. 23-1335-TF) that allowed **Green Mountain Power (GMP)** to include customer-leased batteries in its rate base, enabling GMP to earn an approved rate of return on the capital investments for the batteries.
	Michigan PSC, since 2019, has had a performance incentive (Docket U-20164) to allow **Consumers Energy** to earn up to 15% return on operations and maintenance (O&M) costs if it achieves its demand response capacity growth target (and no payment if less than 50% was achieved). In June 2024, the PUC directed Consumers (Order U-21410) to explore alternative financial incentive mechanisms with a focus on shared savings to enhance the cost-effectiveness and maximize the system impact of demand response programs.[114,clxxxix]

113 Allowing utilities to make a financial return on DER and VPP foundational infrastructure investments by including these investments in utilities' approved rate bases can be controversial as it may inequitably distribute costs among all ratepayers and deter market competition. Cost effectiveness tests can measure the net impact for customers to ensure a reduction in energy bills compared to alternate scenarios and confirm that utility-owned DERs and VPPs are the most cost-effective resources.

114 In 2023, Consumers Energy was criticized by MI PSC staff for the high cost of the demand response program (Staff's Initial Brief, U-21410) and staff recommended that the Commission not approve the program for the incentive. This led to the PUC June 2024 action to explore alternative mechanisms to reduce costs.

System planning

<table>
<tr><th>Regulatory and policy options</th><th>Examples</th></tr>
<tr><td rowspan="5">Clarify benefit-cost assessment frameworks for DERs and VPPs to ensure VPP benefits are comprehensively valued
Require VPPs to be considered in current planning processes (e.g., IRPs, resource adequacy assessments, asset replacement, distribution system planning) so that VPPs are considered as viable options alongside conventional assets
Require integrated grid system planning (e.g., integrated distribution system plan, integrated transmission & distribution plan, grid modernization plans)
Require open-source and/or distributed capacity procurement so that VPPs can compete against conventional assets during capacity procurement process
Require a minimum proportion of resource adequacy procurement to be from VPPs</td><td>Massachusetts passed a bill (G.L.c.164, 92B-92C) in 2022 that requires IOUs to submit Electric Sector Modernization Plans (ESMP) to achieve the state's clean energy goals.[cxc] This bill expanded existing grid modernization planning requirements initiated by the Massachusetts Department of Public Utilities (DPU) in 2014. The new ESMP requirements enhanced the focus on proactive upgrades to the distribution system and established a Grid Modernization Advisory Council (GMAC) as part of the process.

Detailed case study provided in Appendix D.ii.</td></tr>
<tr><td>Since 2018, the Minnesota PUC has required utilities to file Integrated Distribution System plans that include DER baseline data, future DER scenario analysis, hosting capacity, multiple time horizons (5- and 10-year), non-wires alternative analysis, and transportation electrification plans.[cxci]</td></tr>
<tr><td>Georgia PSC approved Georgia Power's 2023 Integrated Resource Plan (IRP) only after the utility agreed to several stipulations, including committing to developing a distributed solar and battery storage pilot to provide grid capacity and reliability benefits and including the program in its 2025 IRP analysis.[cxcii]</td></tr>
<tr><td>In a 2024 State of the State report, the New York Governor directed the NY PSC to implement a Grid of the Future proceeding to "identify smart grid technologies that enable flexible services, like virtual power plants, that can be deployed to achieve New York's clean energy goals at a manageable cost."[cxciii]</td></tr>
<tr><td>Washington passed a bill (HB 1589) in March 2024 that requires utilities to submit integrated system plans; VPP-enabling features of the legislation include requiring plans to align with state clean energy plans and emission reduction targets and to consolidate multiple existing plans (e.g., transportation electrification plans, muti-year rate plans).</td></tr>
</table>

DER deployment

Regulatory and policy options	Examples
Provide financial incentives for DER installation (especially for low-income customers) **Allow utilities to subsidize DERs** (especially for low-income customers) **Streamline DER permitting and interconnection processes** (e.g., provide incentives, set maximum review timelines) **Publish distribution system hosting capacity maps** with clear data standards and regular update requirements **Modify state and tribal energy codes and standards to support DER deployments** where current standards are a barrier **Require distribution utilities to deploy a grid orchestration platform** to better manage the distribution grid and DERs	The **South Carolina PUC** is reviewing proposed modifications to **Duke Energy**'s existing On-Site Generation Service and Premier Power Service Programs that allow the utility to own, operate, and maintain backup generation on-site for large non-residential customers that can be dispatched for grid relief only during emergencies. The proposed change involves introducing a cost-sharing mechanism to incentivize customers to install on-site generation that Duke Energy can dispatch more frequently (not just during emergencies). The cost share would be based on the value of the on-site generation to the utility's system.[cxciv]
	Colorado PUC approved a performance incentive mechanism for **Xcel Energy** to speed up interconnection of DERs (Order 23AL-0188E) in October 2023. The PIM requires Xcel to refund customers 4% of the interconnection fee per day delayed beyond Xcel's internal timeline targets (e.g., 50 days). If Xcel interconnects the DER faster than the target timeline, the value would be credited against any penalties accrued for exceeding the target.[cxcv]
	In November 2024, **New Jersey Board of Public Utilities** proposed upfront fixed and ongoing performance-based incentives for front-of-the-meter and behind-the-meter distributed energy storage systems (Docket QO22080540). Distributed systems could receive $150-300/kW in combined upfront and performance payments based on system size, with additional incentives available for "overburdened communities."
	California PUC issued a series of decisions in 2019, 2020, and 2021 to streamline DER interconnection (Electric Rule 21); the decisions include requirements to establish standard interconnection agreements, conduct public hosting capacity analysis, allow DERs to perform within existing grid constraints, and avoid grid upgrades.[cxcvi] Beyond California, fourteen states across the U.S. (from **California** and **Nevada** to **Illinois** and **Minnesota** to **Maine** and **Vermont**) require utilities to publish hosting capacity maps to share data about where DERs can be deployed on the grid.[115,cxcvii] Utilities have published over 70 maps across over 25 states.
	The **New York PSC** launched a Grid of the Future proceeding (Case 24-E-0165) in April 2024 to study near-term actions that could enhance deployment of grid flexibility resources (including VPPs and DERs) and integrate these assets into grid planning and operations. Initial required elements of the plan included an inventory of what resources are needed, how much is needed, and how to procure these resources, with additional requirements being developed with stakeholder input.[cxcviii]

115 See DOE's U.S. Atlas of Electric Distribution System Hosting Capacity Maps for a summary of utilities with published maps; LBNL's Integrated Distribution System Planning map for additional detail on the states requiring hosting capacity maps, including specific docket information; and NREL's Advanced Hosting Capacity Analysis for additional detail on best practices for hosting capacity maps (e.g., development process, data validation, regulatory reviews).

DER aggregation

Regulatory and policy options	Examples
▸ **Authorize default VPP-opt in** enrollment models ▸ **Allow all DER types to participate in VPPs** (e.g., solar, storage, demand response, heat pumps, etc.) ▸ **Align VPP aggregation standards across IOUs** (e.g., data access rules) ▸ **Provide clear methods for VPP capacity accreditation** ▸ **Ensure open participation for multiple aggregators and OEMs** ▸ **Limit DER incentives to smart, connected DERs** (e.g., smart thermostats instead of standard thermostats that cannot be controlled) ▸ **Direct utilities to file VPP program plans to state PUCs** ▸ **Establish interoperability standards and communications protocols**	In response to Winter Storm Uri and related major generation shortfalls as well as industry requests to allow aggregated DERs to register as supply resources in ERCOT, the **Texas PUC** established an Aggregated Distributed Energy Resource (ADER) Pilot and Task Force (Order 53911) in 2022 to develop a VPP program. Within a year of the PUC initiating this pilot, 7.2 MW of VPP capacity was participating in the pilot and providing dispatchable power to the Texas grid.[cxcix,cc] In December 2023, Texas PUC Commissioners affirmed a desire to expand this initial program to scale VPP deployments across the state.[cci]
	In 2023, **Texas** legislators passed a bill (SB 1699) to establish third-party aggregation requirements for DERs and to authorize the TX PUC to establish rules and requirements for DER aggregators.
	Colorado PUC opened a proceeding (23M-0466EG) in September 2023 to explore implementing third-party managed VPP pilots. The resulting studies enabled additional state VPP actions, including the legislature passing a bill in 2024 requiring **Xcel Energy** to submit a VPP program plan to the PUC by 2025.
	Colorado signed into law (SB24-218) in May 2024 legislation that requires the state's largest IOU (**Xcel**) to submit a VPP plan to the PUC. This built on ongoing actions by the Colorado PUC to advance VPP programs as part of an effort to serve rising demand while mitigating costs for ratepayers.
	Maryland passed the Distributed Renewable Integration and Vehicle Electrification (DRIVE) Act (HB 1256) in May 2024 that requires the state PSC to implement regulations that support bidirectional EV charging and that establish VPP pilot programs throughout the state (including incentive mechanisms that compensate EVs and other DER owners and aggregators).

VPP operations

Regulatory and policy options	Examples
▸ **Implement compensation models that compensate VPPs for the full range of grid benefits delivered** (e.g., capacity benefit, infrastructure costs deferred, environmental benefit)	**New York PSC** has implemented a Value of Distributed Energy Resources (VDER) to compensate DERs based on their system value, including a broad range of benefits such as energy value as well as locational system relief value. *Detailed case study provided in Appendix D.ii.*
	Massachusetts DPU established a Distribution Circuit Multiplier that doubles the financial incentives for system load reduction for DERs that are sited on the top 10% most constrained circuits (published annually by the states' distribution IOUs). This enables DER companies to target sales in areas where devices can offer the greatest value to the grid. Eligible DERs include demand response, renewable generation, and storage.[116,ccii]
	CA Public Utilities Commission established the Avoided Cost Calculator (ACC) in 2005 to determine the value of DERs; the methodology is updated every other year. The avoided cost of electricity is determined based on the value of generation energy, generation capacity, ancillary services, transmission and distribution capacity, and decarbonization policy compliance.

116 See the Clean Peak Distribution Circuit Multiplier Guideline for additional information on eligible DERs, distribution circuit selection, and application processes.

D.ii. Detailed case studies

Detailed case study #1: New York: Value of Distributed Energy Resources (VDER)

Valuation model rewards DERs (and VPPs) for the full set of grid services provided.

VPP regulation summary			
Regulator	NY Department of Public Services (DPS)	**Key VPP regulation (order #)**	Order Regarding Value Stack Compensation (Case 15-E-0751)
IOUs	Con Edison, National Grid, NYSEG, Central Hudson, Orange and Rockland	**Year passed**	2017
Market structure	Within organized market (NYISO), utilities typically do not own generation	**Type of DERs**	Solar, storage, combined heat and power (CHP), digesters, wind, hydro, and fuel cells.
Key features	» Created the Value Stack, a valuation methodology used to determine and compensate DERs for a broad range of system benefits » Compensation is delivered to customers through bill credits		

State and regulator grid objectives with VPP program *(not exhaustive)*

- **Decarbonize power sector** to advance NY's state goal of 100% zero-emissions power by 2040.
- **Manage costs for ratepayers** to maximize the value of the existing grid and available cost-effective resources to reduce costs for New York ratepayers while achieving state clean energy goals.

Program summary

The NY DPS (part of the NY Public Service Commission) refined net metering models first established in 1997 to create the Value of Distributed Energy Resources (VDER) framework used today. With input from stakeholder working groups, NY DPS passed the first VDER Order in 2017, implementing two phases: i) VDER Phase One NEM, and ii) VDER Value Stack. The VDER Phase One NEM program compensates customers for any net excess generation (kWh) provided to the grid (provided as a credit to the customer's next monthly bill). The VDER Value Stack compensates customers based on the system value of the distributed generation (e.g., accounting for the hour of day, location on grid, etc).[cciii] In these early orders, NY DPS proactively included an expectation for a Phase Two to continue refining the Value Stack (e.g., modifying to account for other bulk system, distribution system, and societal values).

The VDER Value Stack compensates projects based on when and where they provide electricity to the grid. The Value Stack compensates DERs for the actual benefits delivered and the utility costs they offset, which includes a broader set of system benefits that were not accounted for in original net metering tariffs. Compensation is delivered in the form of bill credits.

Key success factors to integrate VPPs into utility planning and incentives *(not exhaustive)*

- **Assign value of DER compensation to a range of system benefits** to account for energy, capacity, environmental, demand reduction, locational system relief, and community value.
- **Align economic incentives** to compensate DERs based on monetary value delivered to the grid (not just based on volumetric generation) and allow value stacking across multiple grid benefits, including wholesale market value.
- **Provide location-specific compensation** to reward VPPs that have highest impact on alleviating distribution system constraints.

The VDER Value Stack includes six values for DER compensation:

Value name	Description	Eligible DERs
Energy Value (Locational Based Marginal Price, LBMP)	LBMP is the day-ahead wholesale energy price as determined by NYISO. It changes hourly and is different according to geographic zone.	All technologies.
Capacity Value (Installed Capacity, ICAP)	ICAP is the value of how well a project reduces New York State's energy usage during the most energy-intensive days of the year. Developers can choose from three payout alternatives: 1) pay out based on generation (kWh) delivered to the grid during the year, 2) pay out based on generation (kWh) delivered to the grid during peak windows, 3) pay out based on generation (kWh) delivered during the single peak hour of the year. Alternative 1 and 3 rates change monthly; the Alternative 2 rate is set annually.	All technologies. Dispatchable technologies (stand-alone storage, combined heating and power, digesters, and fuel cells) receive Alternative 3.
Environmental Value (E)	This the value of how much environmental benefit a clean kilowatt-hour brings to the grid and society. The E value is locked in for 25 years.*	PV, wind, hydro, and storage charged exclusively from PV or wind energy. Stand-alone storage is not eligible at this time
Demand Reduction Value (DRV)	DRV is determined by how much a project reduces the utility's future needs to make grid upgrades. DRV is locked in for 10 years.*	All technologies.
Locational System Relief Value (LSRV)	LSRV is available in utility-designated locations where DERs can provide additional benefits to the grid. Each location has a limited number of MW of LSRV capacity available. The LSRV is locked in for 10 years.*	All technologies. Project must be on a utility-specified substation.
Community Credit (CC)	CC is available on a limited basis to encourage the development of Community Distributed Generation (CDG) projects. CC is the successor to the Market Transition Credit (MTC) and is similar in structure. The CC is locked in for 25 years.*	Available for CDG projects including PV and digesters. Wind, hydro, and fuel cells receive CC at a derated value.

Table adapted from NYSERDA's Value Stack Fact Sheet (last updated in 2020).

*Projects will set a fixed rate for their E, DRV, LSRV, and CC values when they make their 25% upgrade payment to the utility. If no utility upgrade costs are required, the values are set when the interconnection agreement is fully executed.

In response to FERC Order 2222 (further discussed in *Chapter 5: Integrating into wholesale markets*), New York introduced the Wholesale Value Stack (WVS) in July 2023, which allows qualifying DER customers to receive compensation for energy and capacity from NYISO in addition to still receiving compensation from VDER environmental, demand reduction, locational system relief, and community credit values.[cciv] Value stacking improves VPP economics by allowing the VPP to qualify for multiple revenue streams (rather than capacity value alone, for example), which provides greater revenue certainty to VPP operators.[ccv]

The VDER tariff is intended to be technology agnostic but primarily focuses on distributed generation resources. DPS is currently conducting a Grid Flexibility Study to evaluate and determine appropriate compensation models that better value flexible resources.

Detailed case study #2: Massachusetts Electric Sector Modernization Plans (ESMP)

State policymakers empower PUC and utilities with stronger grid modernization planning requirements.

VPP regulation summary			
Regulator	MA Department of Public Utilities (DPU)	**Key policy and regulations**	*Legislation:* G.L. c. 164, §§ 92B-92C; An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179, §53 *PUC Order*: ESMP Order (D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12)
IOUs in State	National Grid, Eversource, Until	**Year passed**	2022 Order passed 2024 First filings due
Market structure	Within organized market (ISO-NE), utilities do not own generation	**Type of DERs**	Distributed generation, energy storage, flexible load and demand response solutions
Key features	» Each IOU must develop an electric-sector modernization plan (ESMP) to proactively upgrade the distribution network to support the State's clean energy goals » Explicitly included goals to promote DER adoption and minimize costs to ratepayers		

State and regulator grid objectives (not exhaustive)

- **Enhance decarbonization** by enable integration of renewable energy and distributed energy resources and promoting energy storage and electrification technologies.
- **Enhance grid resilience** by improving overall grid reliability and resilience to climate driven impacts.
- **Minimize impacts to ratepayers** by prioritizing solutions to protect ratepayers while enabling decarbonization goals.

Program summary

In 2012, the MA DPU first opened a gird modernization proceeding to encourage IOUs to invest in distribution system modernization that would enhance reliability, reduce electricity costs, and empower customers.[ccvi] In 2015, the DPU approved the IOUs' first Grid Modernization Plans, preauthorizing certain grid modernization investments through 2021, including DERMS and other foundational communications infrastructure (effectively proactively deeming these as prudent investments that can be included in a utility's rate base).

Building on this work, in 2022, MA policymakers passed legislation as part of the Driving Clean Energy and Offshore Wind Act that requires investor-owned distribution companies to submit an Electric Sector Modernization Plan (ESMP) to the DPU every five years. The ESMP plans should consider nine factors, from extreme weather resilience measures to DER adoption forecasts.[117]

The MA legislature provided explicit direction and authority to the state PUC, empowering regulators to review utility investment plans in the context of broader state goals (e.g., reliability, decarbonization and electrification, affordability). The requirements established in the ESMP process, such as deploying energy storage technologies and advanced metering and telemetry, provide the necessary environment to accelerate DER adoption, establish VPP-enabling infrastructure, and deploy VPPs at scale in Massachusetts.

117 See Section 92 of the MA ESMP legislation for the full list of nine factors that must be considered in utility plans (e.g., describing the availability and suitability of new technologies (e.g., smart inverters, advanced metering and telemetry and energy storage technology) to meet forecasted reliability and resiliency needs; describing alternatives to proposed investments, including changes in rate design, load management and other methods for reducing demand, enabling flexible demand and supporting dispatchable demand response).

Key success factors for utility planning and incentives *(not exhaustive)*

- **Provide explicit direction to the PUC and utilities,** leveraging state policymakers to strengthen the regulatory authority and helped speed up action to promote cost-effective grid modernization.
- **Establish common statewide approaches** for all state IOUs to use (e.g., data access, DER monitoring and verification processes, foundational infrastructure expectations) to help standardize VPP operations and support faster deployment.
- **Adopt best practices for distribution planning** by linking planning requirements to specific grid objectives (listed below), including multiple planning horizons (5-year, 10-year, 2050), and requiring consideration of DERs.
- **Establish diverse stakeholder group,** leveraging the Grid Modernization Advisory Council (GMAC)[118] to provide input on the plans to the utilities ahead of submission to the PUC, helping keep IOUs accountable to ensure system-optimal set of solutions were considered (e.g., VPPs).

D.iii. Key resources for practitioners

VPP Resources

- **Aggregated Distributed Energy Resources in 2024: The Fundamentals** (July 2024, NARUC and NASEO) is an accessible guidebook specifically geared for state regulators and policymakers to understand the fundamentals of VPP grid services, valuation options, and approaches to compensation. **The report includes detailed case studies on MA, HI, and VT VPP programs—including context on the impetus and process that states followed to develop these programs.**
- **VPP Policy Principles** (Feb 2024, RMI and VP3) outlines simple foundational principles to support policymakers in enabling VPPs. *Policy Principles for Enabling Virtual Power Plants (VPPs)* presentation (May 2024) includes specific examples of states and utilities where these principles have been done well. See Appendix D.v. for a summary of the policy principles.
- **Distributed Power Plant Model Tariff** (June 2024, Solar United Neighbors) includes model tariff and model legislation to support state regulators, policymakers, and utilities in implementing VPP-supportive regulatory mechanisms. Solar United Neighbors developed these resources to address the gap identified by the 2023 VPP Liftoff report of a lack of model tariff language that PUCs can adapt for their state.
- **VPP Flipbook** (July 2024, RMI and VP3) includes discussion on effective VPP program design and implementation, including specific examples and resources that could support regulators and policymakers (pages 64-66).

General Grid Planning and Modernization Resources

- **50 States of Grid Modernization** (DSIRE, operated by the N.C. Clean Energy Technology Center) provides a quarterly and annual summary of state policy and regulatory actions supporting grid modernization, including VPP related proceedings. Reports include a summary of specific actions, docket and bill numbers, and broad themes.
- **Integrated Distribution System Planning** (Lawrence Berkeley National Laboratory, DOE): Includes an interactive framework, a catalog of existing state regulatory requirements and policy actions, and additional training materials and best practice information.

118 The Grid Modernization Advisory Council is a stakeholder group that reviews and advises on Massachusetts investor-owned electric distribution utilities' electric-sector modernization plans to promote transparency and engagement in grid planning for Massachusetts.

D.iv. Actions from the Department of Energy

- **Grid Innovation Program**, part of the Grid Resilience and Innovation Partnerships (GRIP) Program, provides financial assistance to states, Tribes, local governments, and public utility commissions to deploy projects that use innovative approaches to T&D and storage infrastructure to enhance grid resilience and reliability
- **Grid Resilience State and Tribal Formula Grant Program**, designed to strengthen and modernize America's power grid against wildfires, extreme weather, and other natural disasters, distributes funding to states, territories, and federally recognized Indian tribes, including Alaska Native Regional Corporations and Alaska Native Village Corporations. The states, territories, and tribes then award these funds to a diverse set of projects
- **Integrated Distribution System Planning** Training and Guidelines to assist regulators in developing requirements for, and in assessing, integrated distribution plans of utilities that consider integrating and utilizing DER services, as well as in understanding needed investments
- **Energy Innovator Fellowship** to fund recent graduates and energy professionals to support public utility commissions, co-ops, Puerto Rican energy associations, Tribes, and other grid operators
- **State Energy Program** to provide funding and technical assistance to enhance energy security, advance state-led initiatives, and increase energy affordability, with a portion of funds allocated to states for energy planning
- **DER Integration and Compensation Initiative** to engage regulators via a cooperative agreement with the National Association of Regulatory Utility Commissioners
- **Grid Modernization Initiative (GMI)** coordinates activities and strategy to create the modern grid of the future
- **State Technical Assistance program** tto provide responsive, on-demand technical assistance to PUCs and state energy offices and match them to subject matter experts at the national labs, as well as a help desk that can address quick, short inquiries
- **EVGrid Assist** to develop best practice guides in collaboration with stakeholders to share learnings, accelerate decision making, and support development of data, tools and analysis to support EV-grid integration

D.v. VPP policy principles from the Virtual Power Plant Partnership

The Virtual Power Plant Partnership (VP3) is a coalition organized by RMI, an independent nonprofit, made up of nonprofit and industry organizations focused on supporting market and policy actions to scale VPP deployment. In February 2024, VP3 released a set of VPP policy principles "to support the fair and efficient growth, integration, valuation, compensation, and advancement of virtual power plants."[ccvii]

The seventeen policy principles identified are:

Category	Principle
DER Asset Base	1. Advance policies to expand beneficial DER adoption by diverse end-users 2. Enable inclusion of all DER technologies in VPPs
VPP Design	3. Utilize best practices in program design 4. Use open communication protocols and standards 5. Enable VPP participation in wholesale and retail markets 6. Regularly update grid service needs to reflect the evolving grid 7. Support comprehensive utility planning and investment decisions
Compensation	8. Fairly compensate VPPs for services delivered 9. Enable value stacking to maximize bene its 10. Support policies that value VPP contributions to resilience, reliability, and sustainability 11. Uphold penalties and liabilities to violations of deployment policies
Customer Experience	12. Maintain customer choice in DER operational control 13. Uphold customer data ownership and simplify enrollment 14. Protect and educate customers 15. Support customer participation in structuring VPP offerings through procedural equity
Utility and System Operator Roles	16. Encourage participation of competitive hardware and service providers 17. Use open-source software and make grid data available

Access additional detail at: https://rmi.org/insight/vpp-policy-principles

D.vi. Summary of existing benefit-cost assessment frameworks from NARUC

NARUC and NASEO's Aggregated Distributed Energy Resources 2024: The Fundamentals report (which was funded by DOE) includes a summary of existing tools for valuing grid services.

Below is the excerpt of Table 13 from the report (page 45) summarizing these tools:

Summary of Existing Tools & Examples of Grid Service Valuation

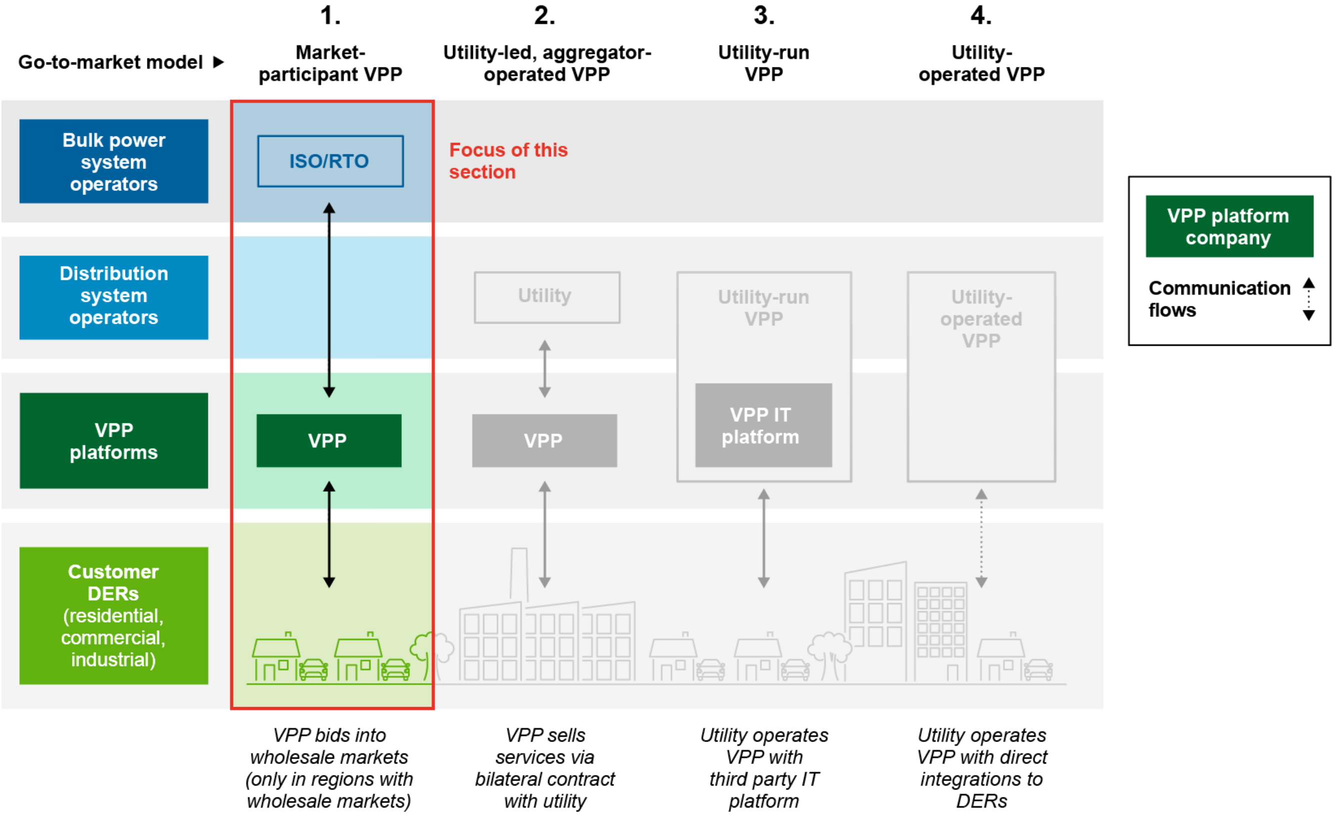
Tool / Methodology Handbook	Description	Energy Benefits Evaluated				Non-Energy Benefits Evaluated	
		Bulk Power Energy & Capacity Grid Services	Bulk Power Essential Reliability Services	Distribution Grid Services	Grid Edge Services	GHGs	Pollutant Emissions or Social Equity
National Standard Practice Manual (NSPM) for Benefit-Cost Analysis of Distributed Energy Resources	Summarizes the BCA principles for DERs and summarizes cost-effectiveness considerations for multiple DERs.	✔	✔	✔		✔	✔
New England Avoided Energy Supply Costs Report	Forecast of estimated annual electric and gas costs that would be avoided due to reductions in gas and electricity use and methods for estimating avoided costs.	✔	✔	✔		✔	
California Avoided Cost Calculator	Estimates '8,760' benefits by year for a DER in California.	✔	✔			✔	
New York Solar Value Stack Calculator	Calculator used to estimate the value of distributed solar in NY.	✔				✔	
Time-Sensitive Value Calculator	Calculator estimates the hourly value of ADERs.	✔	✔			✔	
LBL Interruption Cost Estimator	Estimates the value of lost load by customer type based on region and current SAIDIs and CAIDIs.			✔	✔		
Central Hudson Benefit Cost Handbook (page 587)	Detailed methodology used by Central Hudson Utility in New York for estimating all of the costs and benefits used to estimate cost-effectiveness of DERs.	✔	✔	✔		✔	

EPA Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool	Helps state and local governments explore how clean energy policies and programs affect human health and the value of the health benefits that result from these programs.						✔
Distributional Equity Analysis Guidance	Provides guidance on how utility investments in DERs impact specific populations and communities.						✔

Appendix E: Integrating into wholesale markets

E.i. Detailed case studies

The next section provides an explanation of the communication protocols for a demand response program participating in its corresponding market.



[Detailed case study #1: Leap's participation in CAISO]

VPP overview

Automation capabilities and partnerships with DER technology providers allow VPP scalability in California.

VPP summary			
Program operator	Leap	**VPP size** *(as of 2024)*	500 MW
Market structure	Within organized market (CAISO), utilities own generation	**Type of DERs**	Residential & commercial EV charging, residential & commercial HVAC, residential & commercial batteries, cold storage, water pumping
Location	California ISO	**Time to operationalize**	18 months

Compensation structure	» Capacity payments are based on performance against pre-determined commitments to the ISO, usually via annual contracts. » Energy payments are determined by market prices and clearing results in day-ahead and real-time markets.
Grid services	» Energy (payment from CAISO) and capacity (payment from utilities and Community Choice Aggregators)

Aggregator objectives with VPP program *(not exhaustive)*

- **Monetize DERs** through Resource Adequacy (RA) grid services programs in California.
- **Expand access to VPP participation** beyond large commercial loads, enabling homes and businesses with grid-interactive technologies to easily access these revenue streams.
- **Help reduce upfront costs of DERs** by unlocking new revenue streams for technology providers.
- **Demonstrate the viability of VPPs** as reliable flexible load.

Program summary

Leap partners with technology companies that manufacture and manage DERs to provide energy and capacity services in the CAISO market. Leap contracts with these companies to aggregate residential and commercial DERs, including battery storage systems, electric vehicle charging infrastructure, and smart building technologies.

Leap uses a software solution to integrate with partners' existing systems. Leap connects its partners to the market through API integrations.

Delivered outcomes

- **Provides capacity and energy** services that can competitively bid into CAISO markets.
- **Monetizes 500 MW** of DER capacity for ~40 technology companies.

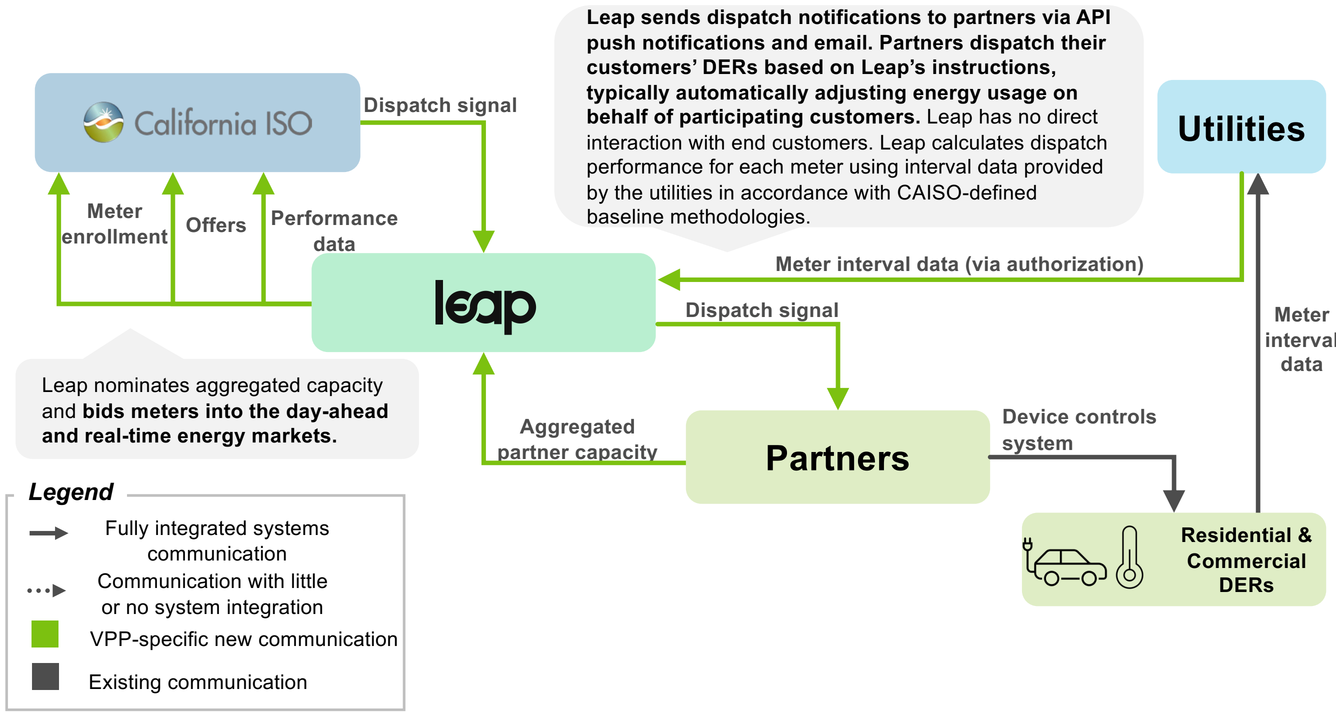
VPP communication protocols & operations

Leap operates in the CAISO energy and capacity markets:

1. Leap's partners start by determining load shed capabilities of their device portfolio, in context with their needs and participation preferences.
2. Partners invite end customers to enroll their DERs for grid services participation through the Leap platform, enabling customers to authorize access to their utility meter interval data for Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric through a single interface.
3. Once Leap receives the utility authorization, Leap submits the service account associated with the meter through CAISO's Demand Response Registration System (DRRS) to register for participation in the appropriate programs. Partners use the Leap portal and API to track the status of program enrollment.

4. Leap sets a curtailment capacity for each meter, aggregates meters with similar characteristics, and submits the aggregation through DRRS each month. Additionally, Leap bids aggregations of customer service accounts into the energy market as a resource bid on an hourly and daily basis through CAISO's Scheduling Infrastructure Business Rules (SIBR) based on partners' bidding preferences.
5. Once CAISO chooses Leap's bids, Leap receives a dispatch signal through the CAISO Customer Market Results Interface (CMRI).
6. Leap then sends dispatch notifications to partners via API push notifications and email. Each dispatch notification will include an amount in kW that is expected to be curtailed.
7. Partners dispatch their customers' DERs, typically automatically adjusting energy usage on behalf of participating customers.
8. Leap receives interval data provided by the utilities for each of their customers. This data is used to calculate performance based on CAISO-defined baseline methodologies. Leap provides performance data through CAISO's Market Results Interface-Settlements system (MRI-S) each month.
9. Leap receives compensation for provided capacity from market counterparties such as utilities and Community Choice Aggregators (CCAs) and receives compensation for energy services from CAISO. Leap then disperses payment to partners, providing settlement and performance details through the Leap portal and API.

VPP communications



E.ii. Market operator case studies of common issue areas and potential solutions

This section provides case studies that share potential approaches that market operators can consider to address issue areas outlined in *Chapter 5: Integrating into wholesale markets* – lack of data access, varied metering & telemetry requirements, and different approaches to aggregator participation models.

Data access

Lever	Example
Create a common and standardized DER register with clear rules on data access	In 2020, the Australian Energy Market Operator (AEMO) established a centralized DER register to provide visibility of DER specifications (e.g., type, capabilities, resource ownership) and location to better manage the grid, improve system reliability as the grid becomes more decentralized, and deliver energy at a more affordable price to customers. Utilities are required to provide DER information in accordance with the DER Register Information Guidelines under the National Electricity Rules. The register provides a common, standardized information fact base that the DER industry, customers, AEMO, distribution utilities, and other third parties such as emergency services can request to access.[119,ccviii,ccix,ccx]

Metering and telemetry

Lever	Example
Establish market-wide metering standards	Ontario IESO has established market-wide standards for meter registration across numerous distribution utilities and 5 million smart meters.[ccxi] Market rules require that each metering installation used for settlement purposes is on a list of pre-approved meters established by IESO that meet specific performance standards, including meeting or exceeding 0.2% accuracy, meeting security requirements, and are programmed according to the IESO Conforming Meter Framework.[ccxii] Regulatory amendments expanded IESO's authority to process and manage bi-directional smart metering data through a centralized Meter Data Management / Repository (MDM/R) in July 2023.[ccxiii] Establishing a market-wide approach to metering simplified and standardized data collection while reducing IT costs to develop, manage, and protect the database. This spurred additional engagement with various grid partners to expand third-party access to this database, including for demand response aggregators.[ccxiv,120]
Allow sub-metering (i.e., meters embedded in DERs) for data collection	SPP, CAISO, NYISO, and MISO allow submetering as the basis for measuring DER performance and compensation for grid services provided. Submetering involves using meters embedded in DERs (e.g., inverters in batteries, meters in solar arrays) for data collection. Allowing submetering in all ISO/RTOs could increase DER participation, since nearly all generation and storage DERs already include device-level meters. The benefits of allowing sub-metering need to be determined against the potential burden of validating and verifying device-level meter data against customer metering data for settlement.
Match telemetry requirements to provided service	CAISO only requires telemetry for resources that provide ancillary services or resources above 10 MW. Rather than requiring these same strict telemetry standards across all services (e.g., 2-6 second telemetry for all DERs and all services), CAISO matches telemetry required to the services offered. This flexible approach allows assets that may not be able to provide sub-hourly telemetry to still participate in wholesale markets and all assets to benefit from reduced participation costs, particularly smaller DERs for which requiring high-frequency telemetry could be a costly barrier.[ccxv]
Allow calculated readings based on a sampling	CAISO, NYISO, PJM, and SPP allow participants to use calculated telemetry readings based on sampling rather than requiring direct telemetry for each DER to participate. This allows a greater number of DERs to participate given relaxed telemetry requirements and reduced participation costs.

119 The Australian Energy Market Commission made a rule obligating AEMO to establish this register in the National Electricity Market in September 2018. AEMO engaged with a wide range of partners, including utilities and industry groups, to design the register and align on the corresponding data sets and data collection processes.

120 Another example is ConnectedSolutions, which has metering authority across multiple utilities in Massachusetts. Common program design across utilities enables standardization of data access, dispatch, monitoring and verification, and DERMS while providing economies of scale for enrollment.

Participation models

Lever	Example
Allow DER aggregations to choose from existing participation models or a new set of participation rules for DER aggregations	NYISO and ISO-NE have adopted a hybrid approach to aggregator participation models to address concerns that existing models may limit participation from DER aggregations. This allows DER aggregators to choose to participate using the model that is most economical for them – either existing models (e.g., storage DER aggregation participating through storage participation models) or a new participation model that is specific to DER aggregations.

E.iii. Key resources for practitioners

- **DER Participation in Wholesale Markets** (January 2025), Lawrence Berkeley National Lab) provides an overview of the six most complex challenges in FERC Order 2222 compliance, various ISO/RTO approaches to address these challenges, and the roles of state energy regulators in the implementation and success of these programs.
- **FERC Order 2222 Implementation** (September 2024, Office of Electricity) shares updates on FERC Order 2222 implementation through bi-monthly reports and webinars. The website includes a DER policy tracker and a library of resources from DOE, NARUC, and NERC.
- **FERC Order 2222 Explainer** (FERC) provides a high-level overview of FERC Order 2222, how it addresses current barriers to DER participation in markets, anticipated timelines for implementation, and additional resources.
- **Grid Investments to Support FERC Order 2222** (January 2024, GridWise Alliance) discusses technologies and corresponding investments that may be required to support FERC Order 2222 implementation.
- **NARUC DER Integration and Compensation Initiative** (March 2023, NARUC) includes a summary of state actions, considerations, and enabling policies related to FERC Order 2222 implementation for state energy decision makers such as PUCs and State Energy Offices.
- **DER Integration into Wholesale Markets and Operations** (January 2022, August 2022, August 2022, ESIG) includes a series of three reports on changes required to integrate DERs into wholesale markets and operations, an assessment of DER initiatives in the UK and Australia, and a proposal for technical foundations, least-regrets strategies, and dialogue to resolve challenges in the U.S.

E.iv. Actions from the Department of Energy

- **Aggregator Code of Conduct** to address the roles and responsibilities of all participants (DER owners, VPPs, distribution system operators, bulk system operators, and regulators) to support DER integration and scale use of DER services
- **Technical assistance** for the use and applications of DERs to support distribution and bulk power system operations for ISO/RTOs, regulators, states, and communities
- **Market and Retail-rate Know-how for the Energy Transition (MARKET)**, led by the National Renewable Energy Lab and Lawrence Berkeley National Lab, to study how existing wholesale markets and retail rates may need to evolve to continue operating the electricity system without compromising reliability and cost. The portfolio of projects includes retail rates, VPPs, wholesale electricity markets, and reliability

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