50 STATES OF

VIRTUAL POWER PLANTS & SUPPORTING DISTRIBUTED ENERGY RESOURCES

2025 State Policy Snapshot

NC CLEAN ENERGY TECHNOLOGY CENTER

Smart Electric Power Alliance

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Authors

Autumn Proudlove, Managing Director - Policy & Markets, NCCETC
Rusty Haynes, Senior Manager - Research & Industry Strategy, SEPA

Contributors

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About This Report

The NC Clean Energy Technology Center and the Smart Electric Power Alliance have compiled all the information contained within this *50 States of Virtual Power Plant and Supporting Distributed Energy Resources: 2025 State Policy Snapshot* report from publicly-available data sources, but the categorizations, characterizations, and summaries are our own.

If you found the information helpful or if you would like to learn more about the methodology and underlying data, please let us know; as of the time of publication, January 2026, we are considering more periodic updates to this report and additional data sets and information related to the topics herein, and we appreciate your feedback. To alert us to new or missing data or a possible correction, please email Autumn Proudlove (afproudl@ncsu.edu) and Rusty Haynes (rhaynes@sepapower.org).

About The North Carolina Clean Energy Technology Center

The NC Clean Energy Technology Center (NCCETC) is a UNC System-chartered Public Service Center administered by the College of Engineering at North Carolina State University. Its mission is to advance a sustainable energy economy by educating, demonstrating, and supporting clean energy technologies, practices, and policies. The Center provides service to the businesses and citizens of North Carolina and beyond relating to the development and adoption of clean energy technologies. Through its programs and activities, the Center envisions and seeks to promote the development and use of clean energy in ways that stimulate a sustainable economy while reducing dependence on foreign sources of energy and mitigating the environmental impacts of fossil fuel use.

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The Smart Electric Power Alliance (SEPA) helps all electric power stakeholders accelerate the transformation to a carbon-free electricity system. SEPA concentrates our focus on the following areas to maximize impact: Transportation, Energy Storage, Resilience, Emerging Technology, Policy, and Energy Equity. SEPA delivers value to our members through research, education, events, working groups, peer engagements, and member projects. We facilitate collaboration, develop innovative strategies and guidance for regulatory and business innovation, and provide actionable solutions for our members and partner organizations. For more information, visit www.sepapower.org.

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Other Publications

The NC Clean Energy Technology Center also publishes the 50 States of Solar, the 50 States of Grid Modernization, the 50 States of Electric Vehicles, and the 50 States of Power Decarbonization on a quarterly basis. Executive summaries of these reports may be found here.

SEPA produces research and reports related to its focus areas, including virtual power plants and supporting DERs. Our research and reports may be found here.

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Glossary of Abbreviations

ADER	Aggregated Distributed Energy Resource
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
BYOD	Bring Your Own Device
BYOT	Bring Your Own Thermostat
C&I	Commercial & Industrial
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DR	Demand Response
DSM	Demand-Side Management
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FERC	Federal Energy Regulatory Commission
HVAC	Heating, Ventilation, and Air Conditioning
IOU	Investor-Owned Utility
IRP	Integrated Resource Plan
ISO	Independent System Operator
kW	Kilowatt
kWh	Kilowatt-Hour
LMI	Low to Moderate Income
MW	Megawatt
RFI	Request for Information

RFP	Request for Proposal
RTO	Regional Transmission Organization
T&D	Transmission and Distribution
TEP	Transportation Electrification Plan or Portfolio
TOU	Time-of-Use
VPP	Virtual Power Plant
V2G	Vehicle-to-Grid

Introduction

The NC Clean Energy Technology Center (NCCETC), in partnership with the Smart Electric Power Alliance (SEPA), is pleased to present the second edition of this comprehensive annual report.[1] The report provides an overview and insights on state-level regulatory and legislative actions related to virtual power plants (VPPs) and distributed energy resource (DER) aggregation, including DERs that support these initiatives. Specifically, it describes scores of meaningful regulatory and legislative actions in 2025, as well as major actions we anticipate in 2026. It is designed to help different audiences – including utilities, utility partners, aggregators, manufacturers, regulators, and legislators – understand the scope, volume, evolution, and trajectory of policy and program developments in the United States.

What is a VPP?

While definitions vary, the U.S. Department of Energy has defined VPPs as "aggregations of DERs that can balance electrical loads and provide utility-scale and utility-grade grid services like a traditional power plant."[2] This report takes a similarly broad approach by encompassing numerous types of DERs that are or can be used in VPPs. These include behind-the-meter (BTM) battery storage, smart thermostats, electric vehicles (EVs) and EV chargers, and electric water heaters, as well as larger customers' curtailable loads.

Why is this important?

Considering that U.S. electricity demand is projected to rise by 25% by 2030 and by 78% by 2050,[3] load growth and resource adequacy are top of mind for many state policymakers, state regulators, and electric utilities. States and utilities are increasingly exploring – and in many cases, prioritizing and utilizing – VPPs as a punctual, versatile solution to meet this challenge. Indeed, by mid-2025, the North American VPP market had reached 37.5 gigawatts (GW) of flexible, BTM capacity, a 14% increase over total VPP capacity in 2024, while the number of active VPP deployments, monetized programs, and unique offtakers each rose by more than 33% during the same time period.[4]

Powered by suites of DERs, VPPs also boost grid flexibility and resilience, while reducing carbon emissions and offering utility customers opportunities (and incentives) to participate.

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[1] The first edition, 50 States of Virtual Power Plants and Supporting Distributed Energy Resources: 2024 State Policy Snapshot, was published in February 2025.
[2] Pathways to Commercial Liftoff: Virtual Power Plants. U.S. Department of Energy, 2023.
[3] Rising Current: America's Growing Electricity Demand. ICF, 2025.
[4] 2025 North America Virtual Power Plant Market Report. Wood Mackenzie, 2025.

What types of VPP models exist?

Several factors, including state-level legislative and regulatory frameworks, shape VPP participation models and program structures. Four distinct models have emerged in the United States thus far:

- Utility-owned and operated VPP
- Utility-led VPP utilizing a third-party platform
- Third-party-operated VPP via contract with a utility
- Direct VPP participation in wholesale electricity markets

Due to the variety of VPP models, state policy frameworks and priorities, and utility practices and priorities, legislative and regulatory actions vary significantly – and are constantly evolving.

Executive Summary

The *2025 Snapshot* includes actions taken by U.S. states and investor-owned electric utilities in 2025 that addressed the following types of policies and programs: (1) behind-the-meter battery storage and multi-technology virtual power plant (VPP) programs, (2) active managed charging programs for electric vehicles (EVs),[5] and (3) demand response (DR) programs utilizing direct load control. It does *not* include actions related to rate design,[6] "passive" managed charging programs for EVs, or DR programs targeting manual customer response, or actions taken by electric cooperative or public power utilities.

A total of 106 actions related to VPPs were taken across 35 states and the District of Columbia in 2025. These include actions related to distributed energy resources (DERs) that support VPPs and DER aggregation. The most prevalent types of actions pertained to individual VPP, demand response, or active managed charging programs implemented by states or utilities. The *Overview of 2025 VPP Activity* section provides additional details on these actions.

The *2025 Snapshot* captures the following actions related to these programs or policy types:

- **Utility Program** - A program aggregating or actively managing customer-sited DERs that is led by an individual utility and only available to that utility's customers.
- **State Program** - A program aggregating or actively managing customer-sited DERs that is available statewide.
- **State Rules** - Rules – established by state legislators or regulators – that govern state or utility DER aggregation programs.
- **State Target** - A requirement established by state legislators or regulators for certain utilities to procure a certain amount of capacity that is associated with aggregated DERs.
- **Utility Target** - A specific goal established by an individual utility to procure a certain amount of capacity that is associated with aggregated DERs.
- **Planning & Procurement** - Rules for evaluating aggregated DERs in integrated resource planning and competitive solicitations, or rules governing competitive solicitations of aggregated DERs.
- **Wholesale Market Participation** - Rules governing the ability of aggregated DERs to participate in wholesale electricity markets.
- **Investigation** - A proceeding or similar initiative focused on gathering information and stakeholder feedback on DER aggregation, typically leading or potentially leading to a specific policy proposal.

[5] Active managed charging, a form of direct load control, supersedes customer charging behavior and imposes utility preferences on charger functionality. Under this arrangement, charging is controlled by communication signals sent from a utility, solution provider, or aggregator to a vehicle or charger. Active managed charging can be event-based or continuous. For more information see, [The State of Managed Charging in 2024](), published by SEPA in 2024.

[6] Effective rate design and price signals, while outside the scope of this report, are tools that also can be deployed to address load growth and yield substantial demand flexibility. The automation of price response to support granular (e.g., hourly) pricing can enhance these outcomes.

Some of the most significant VPP-related actions in 2025 include:

- **Arizona**: Arizona Public Service BYOD Battery Pilot
- **Colorado**: Xcel Energy Aggregator VPP Program
- **Connecticut:** Energy Storage Solutions Program
- **Delaware**: Delmarva Power Affordability and Load Flexibility Portfolio
- **Georgia**: Georgia Power Solar-Plus-Storage Pilot
- **Illinois**: Clean and Reliable Grid Affordability Act (S.B. 25)
- **Louisiana**: Entergy Demand Response and Battery Storage Programs
- **Maryland**: DRIVE Act VPP Programs
- **Minnesota**: Xcel Energy Capacity*Connect Program
- **Virginia**: Dominion Energy VPP Pilot

Based on developments in 2025, four primary trends related to VPP actions are evident:

- The development of utility portfolios of demand-flexibility programs
- The expansion of eligible technologies beyond battery storage
- A continued focus on the use of pilot programs
- The use of DERMS to support VPP programs

Many state-level policy actions and activities related to VPPs and supporting DERs in 2025 were still active at the time of this report's publication and will yield expected additional actions in 2026. Major activities and anticipated actions are included in the *2026 VPP Activity Outlook* section. The body of this report – *2025 VPP Actions by State* – provides summaries, organized by state, of relevant actions and developments.

Overview of 2025 VPP Activity

Table 1 summarizes U.S. state and investor-owned utility actions related to VPPs and VPP-supporting DERs in 2025. Of the 106 actions identified, the most common were related to state and utility energy storage or multi-technology VPP programs (34), state or utility DR programs (24), and state or utility EV managed charging programs (17). These actions occurred across 35 states and the District of Columbia.

Table 1. 2025 Summary of State and Utility VPP Actions

Action Type	# of Actions	% by Type	# of States
State or Utility Storage or Multi-Technology Program	34	%	21
State or Utility Demand Response Program	24	%	15
State or Utility Managed Charging Program	17	%	15
State VPP Rules	10	%	9
Wholesale Market Participation	7	%	5
Planning & Procurement	7	%	4 + D.C.
Investigation	6	%	6
Total	**106**	**100%**	**35 States + D.C.**

Note: The "# of States/ Districts" total is not the sum of the rows, as some states have multiple actions. Percentages are rounded and may not add up to 100%.

Figure 1. 2025 State and Utility VPP Activity

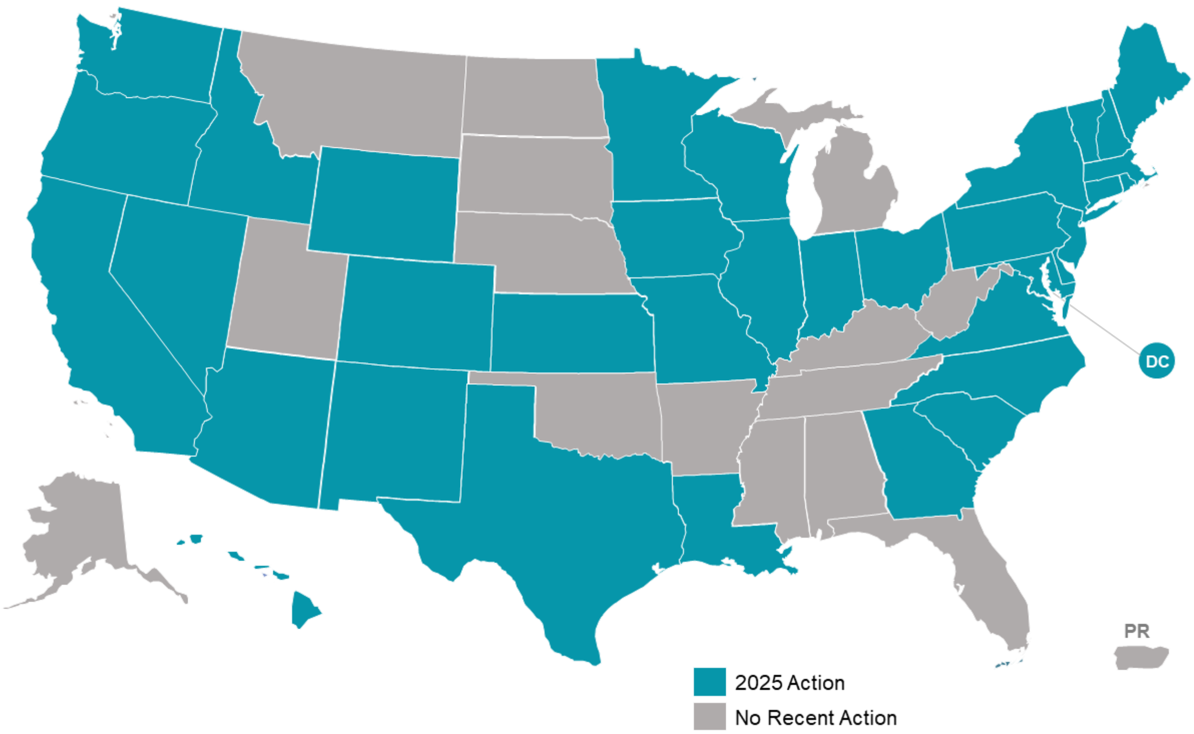


Figure 2. 2025 State and Utility VPP Activity, by Number of Actions

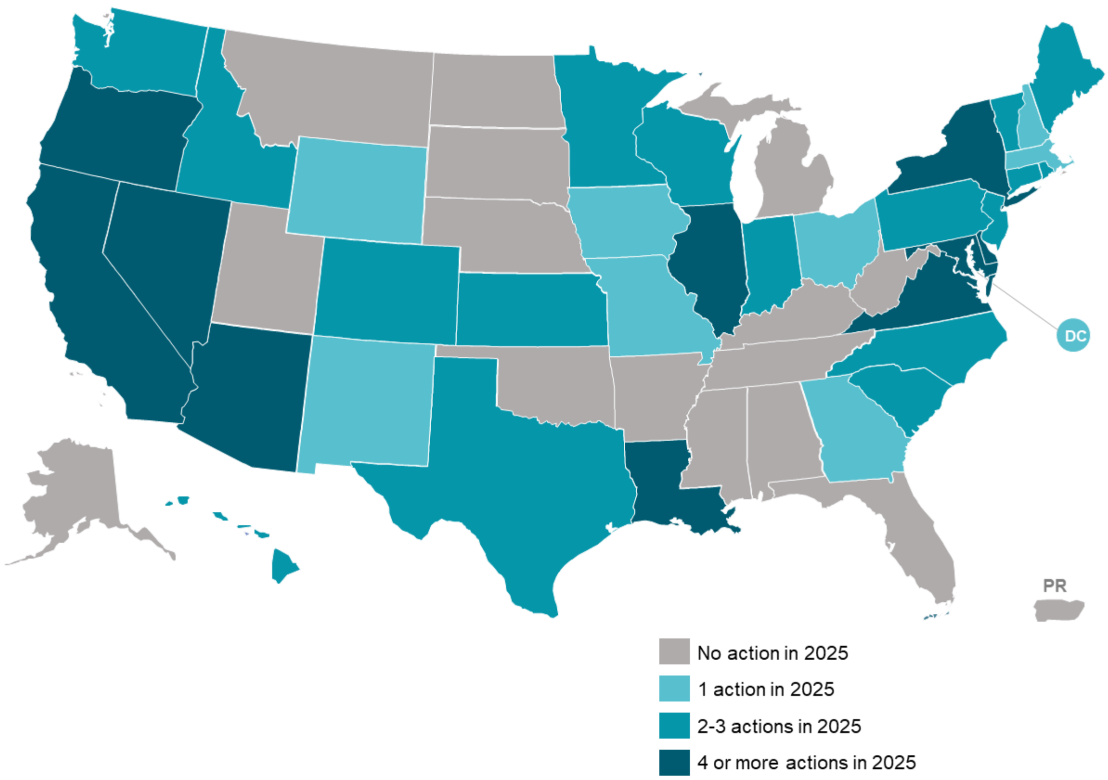
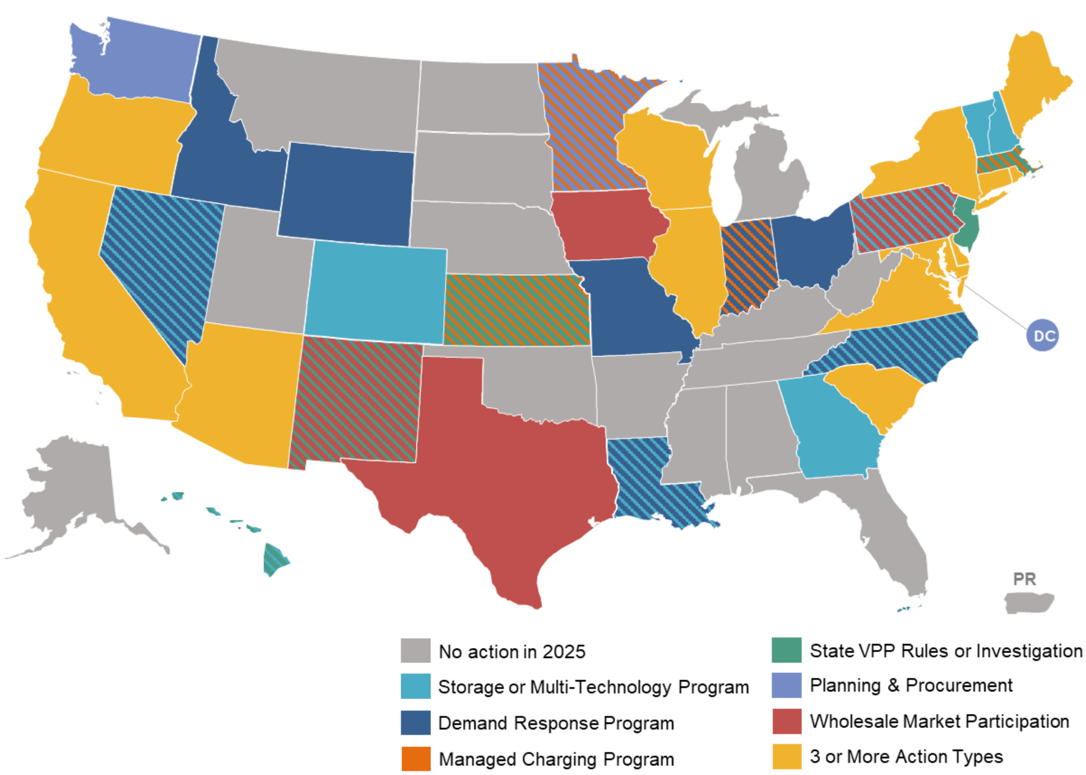


Figure 3. 2025 State and Utility VPP Activity, by Type of Action



Notable 2025 VPP Policy Actions

Arizona: Arizona Public Service BYOD Battery Pilot

The Arizona Corporation Commission approved Arizona Public Service's proposed Bring Your Own Device (BYOD) Battery Pilot in March 2025. The five-year pilot (APS Storage Rewards) will target 5,000 participants and require customers to participate in up to 60 DR events annually. Participants will receive an annual capacity payment based on the average performance delivered by their system.

Colorado: Xcel Energy Aggregator VPP Program

In December 2025, the Colorado Public Utilities Commission approved Xcel Energy's Aggregator VPP (AVPP) program, which will offer performance-based compensation for distributed energy capacity available to support system needs. The program allows a variety of DER technologies to participate, with separate portions of aggregated capacity to be procured via a standard offer and a competitive solicitation.

Connecticut: Energy Storage Solutions Program

In December 2025, the Connecticut Public Utilities Regulatory Authority (PURA) approved modifications to the state's Energy Storage Solutions Program. PURA's decision adopts an alternative performance-based incentive model that focuses on active dispatch, due to low compliance from participants using the previous passive dispatch option. The decision adjusted performance incentives and removed the existing clawback provision.

Delaware: Delmarva Affordability and Load Flexibility Portfolio

Delmarva Power proposed its 2027-2029 Affordability and Load Flexibility Portfolio in December 2025. The portfolio includes a Direct Load Control 2.0 Program, a Bring Your Own Battery Pilot, a Smart Charge Management Program, and a Locational Demand Response Pilot targeting specific feeders and substations where DR can provide non-wires alternatives.

Georgia: Georgia Power Solar-Plus-Storage Pilot

In July 2025, the Georgia Public Service Commission approved Georgia Power's 2025 integrated resource plan (IRP), including a new 50-MW customer-side solar-plus-storage pilot program. The program includes a 25-MW customer-directed portion (load curtailment with performance-based payments) and a 25-MW utility-directed portion (continuous operation for an upfront incentive). Georgia Power plans to deploy a DER management system (DERMS) to manage devices.

Illinois: Clean and Reliable Grid Affordability Act

Illinois legislators passed S.B. 25, the Clean and Reliable Grid Affordability Act, in December 2025, and the state's governor signed the bill into law in January. The Act directs the Illinois Commerce Commission to establish, by June 30, 2026, a scheduled dispatch VPP program for customers eligible for energy storage rebates. The bill also requires investor-owned utilities to file tariffs by the end of 2027 for a separate new VPP program that will allow customers with energy storage and EVs to participate in aggregations.

Louisiana: Entergy Demand Response and Battery Storage Programs

Entergy Louisiana and Entergy New Orleans proposed a suite of DR programs with regulators in 2025, including smart thermostat programs and battery storage VPP programs. The New Orleans City Council approved Entergy New Orleans' programs in December 2025. The City Council also adopted a resolution approving a design for Phase 3 of Entergy's battery storage pilot and directing the utility to file a proposal by March 1, 2026.

Maryland: DRIVE Act VPP Program Proposals

Following the enactment of Maryland's Distributed Renewable Integration and Vehicle Electrification (DRIVE) Act in 2024, the state's investor-owned utilities proposed VPP programs in July 2025 to comply with the Act's provisions. The Maryland Public Service Commission denied the utilities' proposed programs in October 2025, directing them to revise and refile their programs to expand scale and eligibility, among other directives.

Minnesota: Xcel Energy Capacity*Connect Program

Xcel Energy proposed its Capacity*Connect program to Minnesota regulators in October 2025. The program is intended to implement Phase 2 of Xcel's Distributed Capacity Procurement initiative (Phase 1 focused on research and development). The Capacity*Connect program would deploy 50 megawatts (MW) to 200 MW of utility-owned and operated front-of-the-meter (FTM) battery storage by the end of 2028. Xcel is planning a limited DERMS deployment to support the program.

Virginia: Dominion Energy VPP Pilot

In May 2025, Virginia enacted legislation (H.B. 2346 / S.B. 1100) requiring Dominion Energy Virginia to propose a VPP pilot program. Following stakeholder engagement efforts, Dominion Energy filed its proposed program in December 2025. The program would aggregate and manage a variety of new and existing DR and demand-side management (DSM) programs, including new battery storage and managed charging pilots, through a DERMS.

Top VPP Trends of 2025

As a growing number of states and utilities take steps to consider or advance VPPs, several trends are emerging across the United States. This section discusses four trends in VPP activity that emerged in 2025.

Top Trend #1: Portfolios of Utility Flexibility Programs

Some utilities are taking an increasingly holistic approach to VPPs, proposing portfolios of programs that they will manage, often using DERMS. In several cases, utilities are using existing DSM plans or portfolios as the vehicle for these proposals, going beyond traditional DR to include new battery and managed charging programs. Dominion Energy Virginia proposed to use its DSM program portfolio, including new and existing programs, as the foundation of its VPP pilot. In Delaware, Delmarva Power proposed an affordability and load flexibility portfolio of programs. Entergy Louisiana proposed a suite of DR programs, including smart thermostat, battery storage, and EV-charging programs.

Top Trend #2: DERs Beyond Battery Storage

While many initial VPP programs have focused exclusively on battery storage or solar-plus-storage, more programs are allowing a broader set of DER technologies to participate. In Colorado, Xcel Energy’s Aggregator VPP program will allow battery storage, smart thermostats, smart water heaters, smart heat pumps, and EV-charging equipment to participate. Similarly, VPP programs that will be developed in Illinois, pursuant to the Clean and Reliable Grid Affordability Act (S.B. 25), will accommodate energy storage systems, distributed renewable energy systems, smart thermostats, and EV batteries. In Maryland, VPP programs proposed by the state’s utilities would allow EVs with bidirectional capability to participate, in addition to battery storage.

Top Trend #3: Continuing to Focus on Pilots

Although the number of VPP programs continues to rise, the majority of programs still take the form of pilots. The results of these pilots, including the reliability and predictability of capacity and grid services provided through them, will be important to the design of future programs and the potential to scale them. Many major VPP programs proposed by or approved for utilities in 2025 (e.g., Arizona Public Service, Dominion Energy Virginia, Georgia Power, multiple Maryland utilities) take the form of pilots. However, some states and utilities are taking intentional steps to ensure pilots lead to broader programs in the future. For example, Virginia’s 2025 VPP law (H.B. 2346 / S.B. 1100) requires state regulators to undertake a review of the effectiveness of Dominion Energy’s VPP pilot and initiate a proceeding to establish a permanent program.

Top Trend #4: Deploying DERMS to Support VPP Programs

Increasingly, utilities are planning DERMS deployments to support new VPP programs, with some utilities including DERMS plans as part of their broader VPP proposals. For example, Xcel Energy is planning edge DERMS and grid DERMS[7] deployment in Colorado, as well as a limited DERMS deployment in Minnesota to support its proposed Capacity*Connect program. Georgia Power proposed a DERMS deployment to support its new 50-MW customer-side solar-plus-storage pilot, while Maryland's utilities filed DERMS implementation plans as part of their VPP program development. Dominion Energy Virginia plans to utilize a DERMS to manage its portfolio of DR and DSM programs.

[7] An edge DERMS (or aggregator DERMS) manages large numbers and multiple types of (primarily) BTM DERs from multiple DER manufacturers. A grid DERMS is closely tied to a utility's distribution operational technology system, such as an advanced distribution management system (ADMS) and/or supervisory control and data acquisition (SCADA)/energy management system (EMS), and focuses on managing larger FTM DERs and aggregations of BTM DERs, often through integration with an edge DERMS. For more information see, Decoding DERMS: Options for the Future of DER Management, published by SEPA in 2025.

2026 VPP Activity Outlook

We anticipate several significant VPP policy actions and activities in 2026, based on those that occurred in 2025. This section summarizes key anticipated activities in six states in 2026.

New Program Development

Illinois: CRGA Act VPP Tariff Filings

The Clean and Reliable Grid Affordability (CRGA) Act (S.B. 25), enacted in January 2026, directs utilities to file scheduled dispatch VPP tariffs by **June 1, 2026**. The tariffs will apply to storage systems receiving rebates under the Illinois Storage for All program and provide at least $10 per kW of average dispatch. S.B. 25 also requires utilities to file a VPP tariff for other customers by the end of 2027, with Illinois Commerce Commission approval required by the end of 2028.

New Jersey: VPP Program Development

New Jersey's governor issued Executive Order 2 in January 2026, directing the New Jersey Board of Public Utilities to begin developing a VPP program **within 180 days**. Utilities and third-party suppliers will administer the program. It will build on existing state programs, including the third triennium regulatory framework for utility energy efficiency and peak demand reduction programs.

Pennsylvania: Proposed DER Aggregation Rules

In December 2025, the Pennsylvania Public Utility Commission voted to advance proposed rules governing the participation of DER aggregations in the PJM wholesale market. The proposed rules outline regulations that apply to DER operators, DER aggregators, and utilities. Comments on the proposed rules are due **within 60 days** following publication in the Pennsylvania Bulletin.

Expected Program Decisions

Maryland: Revised Utility DRIVE Act Program Proposals

In January 2026, Baltimore Gas & Electric, Delmarva Power & Light, Pepco, and Potomac Edison filed revised proposed DRIVE Act VPP programs with the Maryland Public Service Commission (PSC), following the PSC's denial of their original proposals and directive to refile revised versions. Comments on the utilities' revised proposals are due by **February 23, 2026**, and a hearing on the proposals is scheduled for **March 4, 2026**.

Minnesota: Xcel Energy Capacity*Connect Program

Xcel Energy took the next step in implementing its Distributed Capacity Procurement in October 2025 by proposing the Capacity*Connect program. Capacity*Connect would deploy 50 MW to 200 MW of utility-owned-and-operated FTM storage by the end of 2028. The Minnesota Public

Utilities Commission held a stakeholder workshop and accepted initial comments in late 2025, with supplemental comments due **January 27, 2026**.

Virginia: Dominion Energy VPP Pilot Proposal

Dominion Energy proposed a DSM portfolio and VPP pilot program in December 2025, pursuant to legislation (H.B. 2346 / S.B. 1100) enacted earlier in the year. In January 2026, the Virginia State Corporation Commission consolidated the two applications and requested intervenor testimony by **March 23, 2026**. A hearing is scheduled for **May 18, 2026**.

Additional Programs

VPP programs proposed by several more utilities – including **Delmarva Power** (Delaware), **Duke Energy** (North Carolina), and **Entergy Louisiana** – will be reviewed by state regulators, with decisions expected in 2026.

2025 VPP Actions by State

Arizona

Utility Demand Response Program (Docket E-01933A-25-0103 - *pending*)

In June 2025, Tucson Electric Power initiated a general rate case that includes a proposed Customer Energy Management Framework, a structure through which energy savings and load-optimization initiatives can be evaluated against defined criteria and implemented. The majority of the $24 million annual budget would support load-optimization initiatives – a Whole Home Optimization program and a Whole Business Load Optimization program – designed to reshape how and when energy is used across the two sectors, and to encourage the development of VPPs.

Utility Demand Response Program | Utility Managed Charging Program | Utility Storage or Multi-Technology Program (Docket E-01345A-23-0088 - *decided*)

In December 2025, the Arizona Corporation Commission (ACC) approved Arizona Public Service's (APS) amended 2024 Demand-Side Management (DSM) Plan, which incorporates a Bring-Your-Own-Device (BYOD) Battery Pilot approved by the ACC earlier in the year. The five-year BYOD Battery Pilot targets 5,000 participants, with an estimated capacity of 17 MW. APS's plan also:

- Includes specific initiatives to accommodate the additional scale of dispatchable customer-sited resources to comprise APS's VPP.
- Would expand APS's existing commercial and industrial (C&I) DR program from 67 MW to 100 MW, by shifting to APS direct program implementation and offering new multi-tiered participation options.
- Includes funding to prepare for large facility demand flexibility initiatives, beginning in 2027. APS is developing partnerships with large-load customers that can deliver backup power to the grid when needed.
- Would expand APS's existing residential smart thermostat Cool Rewards program by targeting more than 250 MW, as well as potentially extending the summer timeframe (currently June to September), in response to evolving grid needs, and establishing a cost-effective winter DR season incentive for certain customers.

APS's amended 2024 DSM Plan also boosts SmartCharge program participation to 5,000 customers. This sum includes 1,000 existing participants in a data-sharing component of the program, and an increase of up to 4,000 Active Managed Charging participants, who allow APS to optimize their EV-charging schedules during off-peak times. In addition, the incentives for Active Managed Charging participation rose to $35 for enrollment and $20 per month.

Utility Storage or Multi-Technology Program (Docket E-01345A-22-0144 - *decided*)

In August 2024, following a series of stakeholder workshops, Arizona Public Service (APS) proposed a Bring-Your-Own-Device (BYOD) Battery Pilot that differed from an initial version proposed in APS's 2022 general rate case. In March 2025, the Arizona Corporation Commission approved the newer version – a five-year pilot targeting 5,000 participants – despite Staff concerns regarding program valuations and potential cost shifts to non-participants. Under the approved program (APS Storage Rewards), customers must participate in up to 60 DR events annually (from May to October), with a maximum of one event per day. Participants receive an annual capacity payment of $110 per kilowatt (kW), based on the average kW performance delivered by their system.

California

State Storage or Multi-Technology Program (A.B. 1207 - *enacted*)

California's Demand Side Grid Support (DSGS) program provides financial incentives for DER system owners, operators, and aggregators who make systems available for dispatch. The program was funded by California's Greenhouse Gas Reduction Fund, which itself is funded by the state's cap-and-trade system. Legislation (A.B. 1207) enacted in September 2025 replaced the Greenhouse Gas Reduction Fund with the California Climate Mitigation Fund (which provides direct rebates and investments to reduce household energy costs, including incentives to transition to zero-emission vehicles and energy-efficient housing), thereby eliminating the funding source for the DSGS program.

State Storage or Multi-Technology Program (DSGS Program Rules - *decided*)

In April 2025, prior to the enactment of A.B. 1207, the California Energy Commission (CEC) approved revisions to the Demand Side Grid Support (DSGS) program, which offers multiple incentive structures. (Rather than providing incentives directly to consumers, the program incentivized DSGS providers – retail electric suppliers, federal power marketing administrations, and aggregators – who then recruited participants. DSGS providers then paid incentives to their participants.) Program revisions include:

- Modifying Incentive Option 3: Market-Aware Storage VPP by increasing the minimum nominal aggregate power rating from either 100 kW to 400 kW across all utility service territories, at least one aggregation with a total minimum nameplate power rating of 200 kW, or at least three aggregations with a total minimum nameplate power rating of 100 kW.
- Raising the maximum allowable discharge at a customer site during any hour of a program event, allowing dual participation with market-integrated DR for exports only, and establishing day-ahead and day-of emergency triggers.
- Creating a new Incentive Option 4: Emergency Load Flex VPP, which includes smart thermostat-controlled HVAC systems, electric water heaters, EV supply equipment (EVSE), stationary batteries, and residential smart electrical panels.

The CEC held a workshop in October 2025 to discuss Incentive Option 3 performance data, which may inform future program modifications.

Wholesale Market Participation ([Demand and Distributed Energy Market Integration Initiative] - *pending*)

In January 2025, CAISO launched a new policy initiative targeting demand and distributed energy market integration. The initiative will explore enhancements to or development of participation models and market rules facilitating the representation of demand and distributed energy – either independently or managed in aggregation – in CAISO's day-ahead and real-time markets. Based on stakeholder prioritization and internal analysis of areas identified in the stakeholder catalog process, a working group will explore demand and DER participation competitively bid into the markets and as a coordinated representation of load forecast adjustment.

A discussion paper identifies six areas from which the working group can explore the formalization of problem statements: (1) performance evaluation methodology, (2) enhancing demand flexibility market options, (3) reliability-based DR participation, (4) economic DR participation, (5) DER participation, and (6) expanding demand-side bidding options.

Wholesale Market Participation (Docket R-25-09-004 - *pending*)

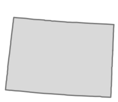
In September 2025, the California Public Utilities Commission (CPUC) initiated a proceeding to evaluate and enhance the consistency, predictability, reliability, and cost-effectiveness of DR. The preliminary scope includes: (1) an examination of the guiding principle the CPUC will use; (2) the standardized data systems, communication protocols, and data transfer processes the CPUC may adopt to support DR initiatives, including dynamic rates; and (3) the policies the CPUC may adopt or amend to make DR resources more consistent and predictable. Policies may include the consideration of dual participation, valuation methodologies and evaluation metrics, CAISO market integration topics, and resource adequacy valuation and slice-of-day implementation.

Investigation (A.B. 740 - *vetoed*)

A.B. 740 passed both houses before California's governor vetoed it in October 2025. A.B. 740 would have required the California Energy Commission, in its next update to the biennial Integrated Energy Policy Report, to adopt a VPP deployment plan that:

- Identifies the resources, policies, and timelines needed for VPPs to help meet statewide load-shift goals;
- Identifies the barriers and opportunities for VPP resources to act as load-modifying resources that reduce a load-serving entity's resource adequacy obligations; and
- Evaluates how the operational configuration of VPPs can be optimized to support specific objectives, including maximizing cost savings to participating and non-participating ratepayers, and maximizing electrical grid system benefits, such as reducing GHG emissions and easing local grid congestion.

Colorado



Utility Storage or Multi-Technology Program (Docket 24A-0547E - *decided*)

In December 2024, Xcel Energy filed a proposed 2025-29 distribution system plan, which includes two categories of DERMS deployment – aggregator DERMS (ADERMS) and grid DERMS (GDERMS) – and a new VPP program (Prime Time VPP) that would allow participation via utility programs and third-party aggregators. The proposed plan also includes numerous non-wires alternatives (NWA) opportunities and a Grid Modernization Adjustment Clause (GMAC) rider. The GMAC rider is designed to recover costs and includes performance screens addressing: (1) interconnection timelines, (2) energization timelines, and (3) reasonable and cost-effective MW targets for flexible load and demand management.

In August 2025, Xcel Energy filed separate settlement agreements addressing the GMAC rider and NWA opportunities. The latter addresses near- and long-term NWA opportunities and procurement, including support for DR. For example, Xcel would identify existing DR on each NWA-eligible feeder and incorporate a portion of the DR capacity into system load relief requirements. In December 2025, the Colorado Public Utilities Commission approved Xcel's plan, including the DERMS investment and modified versions of the GMAC and NWA settlement provisions. The decision directs Xcel to lift its prohibition on NWAs in the Denver metro area and work with the City of Denver to develop an NWA pilot. Regarding the GMAC rider, the decision approves the rider with budget caps, but directs Xcel to revise the performance screening framework.

Utility Storage or Multi-Technology Program (Docket 25A-0061E - *decided*)

In January 2025, Xcel Energy proposed to establish a 125-MW Aggregator Virtual Power Plant (AVPP) program, offering DER aggregators performance-based compensation for capacity obligated to support system needs when requested. Under the proposed program:

- Eligible DERs include battery storage, smart thermostats, smart water heaters, smart heat pumps, and EV chargers. Participating batteries must retain at least 20% of their charge after participation events.
- Customers participating in another performance-based demand management program may not participate.
- Performance is determined by comparing a customer's baseline load to its actual load during an event. Compensation is calibrated to estimates of avoided generation, transmission, and distribution costs.
- Aggregators must control at least 100 kW of aggregate capacity to participate.

In August 2025, in a separate docket addressing its proposed 2025-29 distribution system plan (see above), Xcel Energy filed a settlement agreement that would approve the proposed AVPP program with certain modifications:

- Participating DERs would be limited to 750 kW; total aggregations on a single feeder could not exceed 2 MW. Total aggregations on a single bank could not exceed 5 MW. Methane-based, hydrogen-based, and FTM DERs would not be eligible.
- While the program would use a standard-offer contract, of the 125 MW of aggregate capacity, 5 MW must be procured through a competitive solicitation. Xcel would not participate as an aggregator for the first 24 months.

- Summer-only resources could be called for up to 60 four-hour events per season, while year-round resources could be called for up to 80 four-hour events annually. Events could be called at any time of day.
- Aggregate capacity values for generation, transmission, and distribution would total $264.56/kW (paid incentives would be somewhat lower) in Year 1, with Year 2 value based on market prices.

In December 2025, the Colorado Public Utilities Commission approved the settlement agreement in full.

Utility Storage or Multi-Technology Program (Docket 25A-0194E - *pending*)

In May 2025, Xcel Energy filed its 2026-2027 Renewable Energy Plan. Under the plan, Xcel would continue its Renewable Battery Connect program and increase capacity from a total of 10 MW to 12.5 MW annually, of which 2.5 MW total would be dedicated to income-qualified and disproportionately impacted (IQ/DI) customers (up from 2 MW total). While the standard incentives would stay the same, the IQ/DI Community offering would switch to a tiered incentive structure of $800/kW for IQ customers and $500/kW for DI customers.

Xcel Energy also proposed a new Dispatchable DG Program, as required by S.B. 24-207 (2024), to procure 100 MW of FTM DG co-located with energy storage. Xcel also proposed a new “flexible interconnection” process, as required under S.B. 24-218 (2024), that will allow some resources to avoid making grid upgrades by instead constraining generation through the use of near real-time or schedule-based controls.

In November 2025, Xcel filed a settlement agreement that would partially approve the revisions to the Renewable Battery Connect program. Instead of 12.5 MW annually, Xcel would offer all 55 MW in 2026 (of which 11 MW would be dedicated to IQ/DI customers). The settlement would lower the standard incentive to $250/kW and approve the new tiered structure for IQ/DI incentives, but with different values: $1,000/kW for IQ customers and $500/kW for DI customers. It would also approve the Dispatchable DG Program, with modifications.

As part of a December 2025 decision for Xcel’s distribution system plan (see Docket 24A-0547E), the Colorado Public Utilities Commission found that Xcel’s flexible interconnection proposal was incomplete because it did not include an actual proposed tariff. Xcel must file a flexible interconnection or energization tariff within 60 days of the decision.

Connecticut

State Managed Charging Program (Docket 25-08-06 - *decided*)

In April 2025, in a docket addressing Year 5 of Connecticut’s EV Charging Program, the state’s investor-owned utilities proposed a new incentive for site hosts of multi-unit dwellings (MUDs) who grant the utilities' software provider access to EVSE (including EVSE charging session data) and promote the pilot to their tenants on an ongoing basis. Ambiguity surrounding legislation enacted in July 2025 (S.B. 4) prompted the Connecticut Public Utilities Regulatory

Authority to take steps to clarify the new law and its requirements, issuing a decision in December 2025. The decision:

- Clarifies that income limits established by S.B. 4 do not apply to the managed charging program;
- Requires utilities to submit, by August 2026, a report summarizing the impacts of eligibility revisions to the enrollment incentive for the managed charging program, and indicating whether the enrollment incentive ($100) should be higher;
- Reduces the mandatory enrollment period from two years to one year for customers who voluntarily enroll;
- Revises the program's residential incentive structure, including setting higher incentive levels;
- Requires IOUs to propose, by August 2026, a new methodology for commercial incentives, and potential changes to the program deployment targets; and
- Approves, with modifications, the new incentive for MUD site hosts, while extending the MUD pilot to the end of 2026.

State Rules (S.B. 4 - *enacted*)

In July 2025, Connecticut enacted legislation (S.B. 4) directing the Public Utilities Regulatory Authority (PURA) to expand an existing investigation into Connecticut's net metering and community solar programs by also developing a framework to encourage DERA that can provide grid and retail market services. In addition, the new law directs the Department of Energy and Environmental Protection DEEP and PURA to establish an active DR pilot, which could be coordinated with other states in ISO-NE. Utilities and third parties will submit proposals for review and approval. (Utilities' proposals must add to demand reductions yielded by existing programs.)

State Storage or Multi-Technology Program (Docket 25-08-05 - *decided*)

The Connecticut Public Utilities Regulatory Authority (PURA) issued a decision in December 2025 approving modifications to the state's Energy Storage Solutions program. PURA adopted an alternative performance-based incentive model that Eversource proposed in July 2025, which the Connecticut Green Bank later modified in September 2025. The new model includes the following components:

- The upfront per-kW incentive becomes a flat enrollment incentive: $30/kilowatt-hour (kWh) for residential customers, $130/kWh for residential customers at the grid edge, and $10/kWh for priority commercial customers.
- A declining block incentive will not be used, and the enrollment incentive will only be paid out after the system shows up in the utility's DERMS platform.
- The 5-MW system limit is removed.
- Passive dispatch is phased out due to low participant compliance, and the clawback provision is removed.
- Performance incentives for residential customers will be fixed for all 10 years of enrollment: $300/kW-year for standard residential, $450/kW-year for underserved residential, and $550/kW-year for low-income residential. Commercial customers will receive front-loaded payments covering five years in their first and sixth years: $325/kW-year, followed by $175/kW-year for small and medium commercial, and $275/kW-year, followed by $175/kW-year for large commercial.

- Performance incentives will be the same value year-round.
- The number of summer events will remain the same (30-60), while the number of winter events will rise from one to five to one to 10.
- On a voluntary basis, the Connecticut Green Bank can advance a portion of a residential customer's future performance payments to contractors, who will then apply the funds as an installation cost reduction. In return, the customer will repay the Green Bank via the performance incentives received until the advance is paid off.
- The new model will only apply to new customers starting April 1, 2026; existing customers will remain on the previous incentive model.
- Existing residential customers under the passive dispatch option may transition to the new model's performance incentive, absolving them of clawback provisions. Existing customers under active dispatch may not transition to the new model. (Nor may ConnectedSolutions program participants.)

Delaware

Utility Demand Response Program | Utility Managed Charging Program | Utility Storage or Multi-Technology Program (Docket 25-1554 - *pending*)

In December 2025, Delmarva Power filed its proposed 2027-2029 Affordability and Load Flexibility Portfolio, which includes new DR and battery storage programs. The new BYOD program will provide incentives to customers who enroll their smart thermostats and participate in demand response events. The program would offer $25 per device for enrollment and $40 per year for participation, plus $25 for each device located in a targeted zone.

The proposed plan also includes a new Direct Load Control (DLC) 2.0 program, which would update Delmarva's legacy A/C control program, supplying utility-provided switches (two-way communication load control devices) that enable direct cycling. Participants would receive annual incentives of $40 for 50% cycling, $60 for 75% cycling, and $80 for 100% cycling.

The proposed Bring Your Own Battery (BYOB) Pilot targets customer-owned battery storage for DR and resilience events. Participants would receive a seasonal participation incentive based on enrolled capacity. Incentives are set at $125/kW-year of curtailable capacity for full-year participation, with a maximum incentive of $500 for residential customers and $5,000 for commercial customers. Event-based incentives would be available based on the verified amount of kWh discharged during each event. A $2 million Delaware Sustainable Energy Utility grant would allow Delmarva to support the deployment of customer-sited batteries through this program.

Delmarva Power's Locational Demand Response (LDR) Pilot targets feeders and substations to evaluate LDR as a NWA available to customers located on targeted feeders. Delmarva plans to expand recruitment to additional customers in constrained feeder zones. If a customer is enrolled in the LDR pilot along with one of the three proposed programs above (BYOD, DLC 2.0, or BYOB), they may receive a locational bonus payment depending on the program: $25/year for BYOD customers, $100/kW up to $1,000 for BYOB residential customers, and $100/kW up to $8,000 for BYOB commercial customers. Bonus incentives for DLC 2.0 customers are limited to targeted marketing and locational testing.

The proposed plan also includes a new Smart Charge Management program that would provide direct management of charging schedules to residential customers with a qualifying EV or who use a qualified Level 2 charger. Technologies must be capable of sharing charging data with the implementation vendor. Customers would receive monthly incentives of $5 for a Level 1 charger and $10 for a Level 2 charger.

District of Columbia

Planning & Procurement (RFP - *pending*)

In July 2025, the District of Columbia Public Service Commission (PSC) issued a request for proposals (RFP) for a VPP or DER management system pilot project. The PSC invited projects that can demonstrate grid interactivity and interoperability of buildings and DERs, including their ability to act as grid resources. Total funding available is approximately $4.44 million. Proposals were due in January 2026.

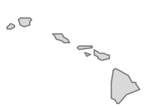
Georgia

Utility Storage or Multi-Technology Program (Docket 56002 - *decided*)

In January 2025, Georgia Power filed its proposed 2025 IRP, covering the 20 years from 2025 to 2044. The proposal included a new 50-MW customer-side solar-plus-storage pilot program for residential and small commercial customers, with equal portions (25 MW) allocated for a customer-directed model (load curtailment with performance-based payments) and a utility-directed model (continuous operation of energy storage for an upfront incentive). Georgia Power also proposed deploying a DERMS, as well as a resilience program for large C&I customers, which enables participants to retain ownership of DER systems while participating in DR events.

In July 2025, the Georgia Public Service Commission approved a stipulation that includes the solar-plus-storage program, DERMS deployment, and the new C&I resilience program. Georgia Power subsequently filed a revised DER Customer-Owned (DCO-1) tariff and a new Large Customer-Owned Resiliency (LCOR-1) rider. The revised DCO-1 tariff extends the tariff's initial term from 15 years to December 31, 2031. The LCOR-1 rider, established in connection with the approved C&I resilience program, allows participants to receive compensation for demand reductions via BTM DERs during DR events.

Hawaii



State Rules (S.B. 589 - *enacted*)

In July 2025, Hawaii enacted legislation (S.B. 589) directing the state Hawaii Public Utilities

Commission to develop tariffs – with “fair compensation” – for grid services programs, microgrids, and community-based renewable energy. Tariffs must include a rider for energy storage systems and provisions that allow aggregators to participate in grid services programs. Energy exported to the grid by participating customers with photovoltaic (PV) systems paired with energy storage as part of a grid service program will be credited via a time-based rate that reflects resiliency, capacity, and ancillary service value.

Utility Storage or Multi-Technology Program (Docket 2019-0323 - *Decided*)

In March 2025, the Hawaii Public Utilities Commission (PUC) adopted revisions to Hawaiian Electric’s BYOD program (now BYOD+), available to customer-sited battery systems paired with renewable energy generation. Program revisions include:

- Converting the program’s aggregate cap from island-specific limits to a single, statewide cap of 50 MW, split equally between low-to-moderate-income (LMI) customers and non-LMI customers;
- Raising the upfront incentive level from $100/kW (up to $500) to $400/kW for non-LMI customers and $800/kW for LMI customers;
- Retiring the monthly capacity performance incentive ($5/kW), but raising the credit amount for controlled energy exports from the evening peak export rate under the Smart DER Tariff to the retail rate for exports during scheduled export time; and
- Increases the customer commitment period from three years to five years.

In addition, the PUC concluded in May 2025 that its previously adopted Advanced Rate Design with time-of-use (TOU) pricing for Hawaiian Electric did not achieve its goals, and therefore declined to extend the rates in their current form to all customers. Instead, the PUC will reassess this topic in a future proceeding that pairs TOU rates with complementary demand management technology and/or programs.

Utility Storage or Multi-Technology Program (Docket PC-201888 - *decided*)

In October 2025, Hawaiian Electric filed a proposed non-docketed stipulation that would revise its Net Energy Metering Plus (NEM+) tariff. The “Proposed NEM+" tariff – an export-limited option, rather than a non-export option – would constitute a new customer option (i.e., in addition to the existing NEM+ tariff), as opposed to a replacement. Customers who enroll in the Proposed NEM+ option must enroll in an available grid services program, and systems must comply with specific technical requirements. The Hawaii Public Utilities Commission approved the proposal in November 2025.

Idaho

Utility Demand Response Program (Docket IPC-E-25-09 - *decided*)

In March 2025, Idaho Power requested to modify its A/C Cool Credit program by adding a Bring-Your-Own-Thermostat (BYOT) option. Under the BYOT option, Idaho Power would utilize residential customers’ smart thermostats to reduce demand when events are called. A third-party aggregator would coordinate directly with equipment manufacturers to facilitate the offering and provide a centralized interface that Idaho Power can use to communicate with all major thermostat brands. In the first year, participants in the BYOT program would receive a $50 enrollment incentive; in subsequent years, they would receive a monthly participation incentive from June to September. To qualify for incentives, customers must participate in at least 50% of seasonal event hours.

In July 2025, the Idaho Public Utilities Commission approved Idaho Power's request, with several minor modifications (primarily related to program enrollment and cost-effectiveness), and directed it to propose to continue the BYOT option before the initial three-year period expires.

Utility Demand Response Program (Docket IPC-E-24-37 - *decided*)

In January 2025, the Idaho Public Utilities Commission approved a proposal by Idaho Power to revise two DR programs: the Irrigation Peak Rewards Program (Schedule 23) and the Flex Peak Program (Schedule 82). The revisions to Schedule 23 include establishing an early-interruption option under which events end by 9 p.m., and participants receive 50% of the standard incentive, and clarifying language around emergency dispatch in order to increase participant awareness. The revisions to Schedule 82 include establishing a $1,500 reimbursement for participants who install load-control devices, adjusting the calculations for baseline cap on event days, allowing day-of load-modifications when a participant initiates a partial/complete shutdown of the facility site during the day-of load hour, and increasing flexibility for customers to base their expected participation on more up-to-date operations.

Illinois

State Rules (S.B. 25 - *enacted*)

In December 2025, Illinois's legislature passed sweeping legislation (S.B. 25) that includes robust support for numerous clean energy technologies and initiatives. Illinois's governor signed the bill into law in January 2026. S.B. 25 directs the Illinois Commerce Commission (ICC) to establish a scheduled dispatch VPP program by June 30, 2026. Under the program:

- Storage systems that receive a rebate under a new program established by S.B. 25 – Illinois Storage for All – and community renewable energy generation projects paired with an energy storage system must participate.
- Participation during called events must be at least $10/kW of average dispatch.
- Utilities must file an initial scheduled dispatch VPP tariff by June 1, 2026, for ICC approval by June 30, 2026.

S.B. 25 establishes a timeline for another new VPP program via a tariff offering that will allow customers with battery storage, non-battery storage, and EVs to enroll devices in the program via aggregators or directly with a utility. (The VPP program described above applies only to customers eligible for energy storage rebates). Large utilities are required to file a VPP tariff by the end of 2027, with ICC approval required by the end of 2028.

S.B. 25 also establishes new review guidelines for IRPs, which now must utilize the expansion of energy storage, VPPs, distributed energy storage, energy efficiency, DR, TOU rates, or any other clean energy strategies to the maximum extent practicable to resolve any identified resource adequacy shortfall or reliability violation in a cost-effective, affordable, timely, and clean manner.

Utility Demand Response Program | Utility Storage or Multi-Technology Program (Docket 25-0678 - *withdrawn*)

In July 2025, Commonwealth Edison (ComEd) proposed three new tariffs designed to comply with an Illinois Commerce Commission (ICC) order in ComEd's Multi-Year Grid Plan docket (Docket 22-0486):

- Rider BYODLR - Bring Your Own Device Load Reduction Program offers an annual incentive to customers who make an approved device (smart thermostat) available for control by ComEd or an approved aggregator during events. This option is not available to net metering customers or customers participating in other load-reduction programs (including Rider VPP and Rider CSS), or to customers without an AMI meter. Events may be called for a demonstration of load-reduction capability, a response to a capacity shortage, or to preserve the response ability of other load-reduction resources.
- Rider VPP - Virtual Power Plant Program enables customers with energy storage devices to commit to system injections either directly through ComEd or an approved aggregator. The customer or aggregator will receive an annual incentive, initially set at $10/kWh injected based on the nameplate capacity of the storage system divided by the total number of committed hours. Rider VPP is not open to customers taking service under Rider CSS, Rider BYODLR, or several other load-reduction tariffs.
- Rider CSS - Community Solar Plus Storage Program is effectively the same as Rider VPP, but is only available to community solar projects with energy storage. (That is, the rider applies to community solar providers, not community solar subscribers. However, a provider presumably could choose to pass along the incentive to subscribers). The daily dispatch window for Rider CSS is five hours, and the annual incentive is the same as the incentive under Rider VPP.

In November 2025, ComEd filed a motion to withdraw its application. ComEd cited the Illinois legislature’s passage of the Clean and Reliable Grid Affordability Act (S.B. 25), observing that S.B. 25 touches on CSS and VPP program components such as device eligibility, compensation levels, and measurement of participant performance, and could be cause for rider revision. ComEd intends to revise its proposals in response to S.B. 25 (subsequently enacted) and additional feedback. ComEd acknowledged that S.B. 25 does not require it to file a scheduled dispatch proposal until June 1, 2026, and does not require a BYOD or smart thermostat program, but it committed to filing its scheduled dispatch program proposal ahead of schedule and will include a revised BYOD or smart thermostat program within its proposal.

Utility Managed Charging Program (Docket 24-0494 - *decided*)

In March 2025, the Illinois Commerce Commission issued a final decision addressing Ameren Illinois’s Beneficial Electrification Plan update, proposed in July 2024. The decision approves a new residential managed charging program that offers an enrollment incentive of $50 and a participation incentive of $10 per month.

Utility Storage or Multi-Technology Program (Docket 22-0487 - *pending*)

In March 2024, Ameren Illinois refiled its proposed Integrated Grid Plan, which includes Advanced Distribution Management System (ADMS) upgrades, system automation and control, DERMS, DR, and DSM pilots, energy storage pilots, and an NWA analysis, as well as proposals for a VPP program and a community solar-plus-storage program. The Illinois Commerce Commission (ICC) issued a final order in December 2024, approving Ameren's refiled plan, with some modifications. Among other things, the ICC's order approved a process for developing the VPP and community solar-plus-storage programs, while also directing Ameren to work with Staff to consider the development of a geotargeted DR program. In March 2025, at Ameren's request, the ICC issued an amendatory order correcting certain errors related to program budgets and reporting requirements.

Indiana

Utility Demand Response Program | Utility Managed Charging Program (Docket 46255 - *decided*)

In May 2025, Indiana Michigan Power (IMP) proposed a 2026-2028 DSM plan, which includes DR and conservation voltage reduction (CVR) programs. The plan would largely continue IMP's existing DR programs, while adding a new battery storage program, as well as a commercial peak time rebate and connected energy management system programs. (Few details regarding the residential battery storage and commercial connected energy management system programs are available.) It would also create a financial incentive for IMP based on DR program target attainment and costs incurred. A stipulation and settlement filed in September would approve IMP's proposed DSM plan -- including existing DR programs, the new battery storage program, the new peak time rebate, and the connected energy management system program and IMP's own DR financial incentive -- but with some modifications. Notably, IMP would assemble a DSM Oversight Board (including nonprofits and local and state government entities) charged with reviewing the programs, assessing their cost-effectiveness, and proposing modifications when necessary.

IMP's proposed plan also includes two EV-focused programs: an EV rate and an EV managed charging program. The latter would provide an incentive of $8 per month; participants would either enroll for planned charging time periods or allow direct control of their charging. The Indiana Utility Regulatory Commission approved the settlement in December 2025.

Iowa

Wholesale Market Participation (Docket RMU-2025-0020 - *decided*)

In September 2025, the Iowa Utilities Commission (IUC) opened a new rulemaking docket to consider changes to the treatment of third-party aggregators of retail customers (ARCs). Federal Energy Regulatory Commission (FERC) Order 719 required all RTOs and ISOs to allow third-party ARCs to bid DR on behalf of retail customers into RTO/ISO markets. Order 719 also allowed relevant electric retail regulatory authorities to prohibit ARCs from operating DR programs within their jurisdiction, which the IUC allowed on a temporary basis in 2010 and a permanent basis in 2013. FERC Order 2222 directed RTOs and ISOs to allow ARCs of other DERs to access RTO/ISO markets without the option for regulatory authorities to opt out. In December 2025, the IUC issued an order that immediately lifted the prohibition against ARCs and allowed ARCs to offer DR aggregation services.

Kansas

State Rules (H.B. 2149 - *enacted*)

In April 2025, Kansas enacted legislation (H.B. 2149) specifying that neither cooperative utilities nor municipal utilities are required to participate in any DR or DER aggregation programs.

Utility Managed Charging Program (Docket 25-EKCE-169-TAR - *decided*)

In September 2024, Evergy Kansas Metro and Evergy Kansas Central proposed a Phase 2 Transportation Electrification Portfolio, including a new residential managed charging pilot and a fleet advisory services program. The proposed residential-managed charging pilot is split into two sub-programs: an opt-out passive program and an opt-in active program. The passive program would provide communications to encourage customers to shift their charging to off-peak times. There is no direct incentive available via the passive program, but TOU customers may see lower bills as they shift charging habits. The active program would provide an enrollment incentive and a monthly participation incentive, and would allow Evergy to control participants' chargers. Participants must charge at home at least once monthly and may not override Evergy's schedule more than twice monthly. In February 2025, multiple parties filed a settlement agreement that would raise the number of monthly charging days from one to two. In March 2025, the KCC approved the settlement agreement in full.

Louisiana

Utility Demand Response Program | Utility Storage or Multi-Technology Program (Docket U-37595 - *pending*)

In May 2025, Entergy Louisiana proposed a suite of DR programs, with a proposed budget of $81 million from 2026-30. The proposed residential programs are modeled on similar programs offered by Entergy New Orleans. They include:

- A smart thermostat program offering enrollment and annual participation incentives
- A BTM battery storage program offering incentives of $75 per installed kWh (up to $1,000) for enrollment and $125/average kW of load reduction (up to $600 per year). Entergy may access and utilize up to 80% of the stored energy from a participating system on peak demand days for three-hour events, up to 120 hours per year. Participants could opt out of events, but the participation incentive would be lower.

- A behavioral EV-charging program

For C&I customers, Entergy proposed a new aggregated capacity DR program, offering seasonal incentives to customers that reduce their load during certain events. Customers could use direct load control, manual response, or eligible BTM assets to participate; resources must be dispatchable. Incentives are based on the average kW of load reduction, varying by season. Entergy also proposed an irrigation load-control program, providing monthly incentives to participating agricultural customers.

In addition, Entergy proposed a performance incentive mechanism (PIM) for these DR programs, with annual targets rising to 155 MW in the fifth year. Entergy's proposed PIM is structured as follows:

- For meeting less than 80% of its stated DR target in a given year, it would receive no incentive.
- For meeting 80% to 90% of its stated target, it would receive 2% of DR portfolio costs for the program year.
- For meeting 90% to 105% of its stated target, it would receive 4% of DR portfolio costs for the program year.
- For meeting 105% to 120% of its stated target, it would receive 6% of DR portfolio costs for the program year.
- For meeting more than 120% of its stated target, it would receive 8% of DR portfolio costs for the program year.

Utility Demand Response Program | Utility Storage or Multi-Technology Program (City Council Docket UD-23-01 - *decided*)

In June 2025, Entergy New Orleans, which is regulated by the New Orleans City Council, filed a proposed Energy Smart Program (Years 16-18), which includes three new residential DR programs and one new commercial DR program. The proposed residential programs include:

- A Bring-Your-Own-Thermostat Demand Response Program, which provides an enrollment incentive and seasonal participation incentives
- A Battery Demand Response Program, which provides a $125/kW participation incentive (up to $600/year)
- A behavioral EV-charging program

The Large Commercial Automated Demand Response Program would procure 10.5 MW of new DR, remotely controlled by a third-party program administrator. The City Council approved the Energy Smart Program Years 16-18 in December 2025.

Utility Storage or Multi-Technology Program (City Council Docket UD-24-02 - *decided*)

In November 2024, the New Orleans City Council, which regulates Entergy New Orleans (ENO), opened a proceeding to evaluate methods to expand DER availability in light of increasing frequency and intensity of severe weather events, rapidly changing climate conditions, and rising grid demand. This proceeding is designed to examine related policies and funding mechanisms, and to establish a vendor-neutral program to facilitate broader DER deployment.

In July 2025, advisors to the City Council submitted a report regarding proposed DER programs and policies, including separate VPP programs proposed by Together New Orleans/Alliance for Affordable Energy (TNO/AAE) and ENO. The report summarized comments, recommended changes to existing policies, analyzed proposed funding mechanisms, and provided additional guidance. The advisors' report concluded that the proposed VPP programs merit further consideration and development, noting that both proposals likely would cost around $30 million over a 10-year period. The report recommended taking a measured approach, by expanding ENO's existing DER pilot to include the following features: (1) upfront and ongoing incentive levels that satisfy both major proposals and ensure long-term participation; (2) data-driven incentives or allocated funds for LMI customers, to ensure significant LMI participation; (3) a vendor-neutral approach; (4) an efficient, objective, and straightforward pre-approval process for third-party vendors; (5) leveraging Entergy's existing battery storage pilot program and vendors; (6) an identified funding source; (7) cost-effectiveness; (8) minimal ratepayer bill impacts; and (9) sufficient reporting and data gathering to help develop a permanent VPP tariff.

In December 2025, the City Council adopted the resolution establishing a DER program and directed ENO to file a proposal by March 1, 2026. The program will last for three years, operated as Phase 3 of ENO's battery storage pilot, and will include the following provisions:

- Participating systems could be customer- or third-party-owned.
- The upfront incentive is $400/kWh installed for non-LMI residential and commercial customers and $480/kWh installed for LMI residential customers, up to $10,000/residential customer and $100,000/commercial customer, with a three-year budget of $28 million.
- Half of the incentives should be dedicated to residential customers, and half to commercial customers; 40% of the residential portion should be reserved for LMI customers.
- Customers who receive an upfront incentive must participate for seven years. The residential participation incentive is $125/average kW delivered across all events, up to $600/year; the commercial participation incentive is $250/average kW delivered across all events, up to $1,800/year.
- If a customer does not participate in called events, they will be subject to a to-be-valued clawback of the upfront incentive. ENO could call up to 30 events per year.
- FERC settlement money could be used as bill credits to mitigate any incremental rate impact on customer bills resulting from cost recovery.

Maine

Investigation (Docket 2025-00343 - *pending*)

In November 2025, the Maine Public Utilities Commission issued a request for information (RFI) focused on enhancing grid resiliency, addressing rising storm-related costs, and improving overall reliability. The RFI seeks input from utilities and third parties on several key areas, including identifying innovative opportunities to improve reliability and resiliency by maximizing the value of past utility investments, exploring options to better utilize existing demand response programs and DERs, assessing the potential for using VPPs to support grid operations at the distribution level during peak demand events, and determining the criteria other utilities use to evaluate whether utility-owned energy storage can enhance reliability and resiliency. Comments were due in December 2025.

State Managed Charging Program | State Storage or Multi-Technology Program (Docket 2024-00310 - *decided*)

In November 2024, Efficiency Maine filed a draft Triennial Plan VI for FY 2026-28, which aims to deliver 137 MW of summer peak-load reductions by 2028. Under the plan, Efficiency Maine would expand its existing DER initiative by offering new participation pathways for DERs, including EV charging. The proposed plan includes:

- A new $300 incentive for networked chargers that are pre-set to shift charging away from peak demand periods; customers may opt out on any day. This incentive is designed to offset the incremental cost of a smart charger at the point of purchase, to encourage residential customers to pair the purchase of a new or used EV with internet-connected home charging.
- A managed charging incentive ($50 for enrollment plus $50 for annual participation) for residential customers with an existing networked charger or telematic EV.
- An incentive – deemed the Renewable Reliability measure – for small batteries used for emergency backup power, inspired by a similar program implemented by Green Mountain Power in Vermont. Aggregators (original equipment manufacturers, third-party owners, and third-party electric load aggregators) would work out payment arrangements with customers (residential and small commercial), with compensation based on performance. Initially, approved aggregators would receive $200/kW per year.
- A $100/kW incentive – deemed the Open Access Battery Incentive – for customers with existing batteries who enroll via a DERMS platform. This measure is a continuation of an incentive from the previous plan (Triennial Plan V) that was created for residential and small commercial customers with a storage capacity of up to 20 kW.

In April 2025, the Maine Public Utilities Commission approved Efficiency Maine's Triennial Plan VI, including its $528.4 million budget.

Maryland

State Rules (Case 9778 - *pending*)

In February 2025, the Maryland Public Service Commission (PSC) launched a proceeding for the Public Conference 44 Interconnection Work Group to track activities and filings concerning implementation of VPP and vehicle-to-grid services in Maryland. These developments support FERC Order 2222, regarding VPPs, as well as goals of the Distributed Renewable Integration and Vehicle Electrification (DRIVE) Act. In April 2025, the PSC issued an order on VPP implementation, directing Baltimore Gas & Electric (BGE), Pepco, Delmarva Power & Light, Potomac Edison, and Southern Maryland Electric Cooperative (SMECO) to file within six months reports addressing DERMS plans, conceptual reports on DER registration, and data protocols. The order also directed Potomac Edison to file a conceptual report on non-AMI VPPs. The Interconnection Work Group must make recommendations on program development and design to support VPPs.

In October 2025, the Interconnection Work Group filed a status report, explaining that it had reviewed six versions of VPP regulations and identifying significant non-consensus issues of VPP classification system definitions, injectable resources vs. DR in the DER registry, device-level metering and submetering, dispatchable range, utility review of VPPs, double counting, utility code of conduct regulations, and information-sharing requirements. The utilities also filed their reports, as summarized below:

- SMECO plans to implement an ADMS to eventually enable DERMS capabilities for active control of DERs within the ADMS by 2030, with an estimated cost of $5 million. For DER registration, SMECO plans to establish a Secure File Transfer Protocol (SFTP) site. For device-level metering, SMECO states that its AMI communications bandwidth is saturated and does not have sufficient connectivity to achieve a VPP, so modeling and assumptions will be used. For customer data sharing, SMECO supports use of Green Button Connect and is receptive to a unified data access platform.
- Delmarva, BGE, and Pepco reported that BGE's DERMS implementation Project 1 aimed to go live toward the end of 2025, with Project 2 set for early 2026. Delmarva and Pepco's DERMS platform is targeting early 2027. Regarding DER registration, the utilities proposed a "maintain and observe" approach to their strategy, adding new data fields from Maryland's draft VPP regulations, and reporting monthly DER registration data. Regarding device-level metering, they proposed continued partnerships with third-party Grid Edge DERMS vendors for such device-level data, subject to change as VPP programs expand and DER technology evolves. Regarding information-sharing, they recommended further analysis and creating a relevant Work Group and acknowledge Green Button Connect.
- Potomac Edison asked the PSC to provide further direction such that long-term programs (including VPPs) allow utilities to plan for needed investment in DERMS. Regarding a DER registry, it recommended utilizing its internal database, which would remain confidential, and filing annual reports. Regarding device-level metering, it recommended operating as-is and awaiting DSSS results. In terms of customer data and third-party access, it recommended a staged approach and would seek to develop a third-party data access tariff. The report also addresses communications protocols, and Potomac Edison does not believe AMI is necessary to implement VPPs.

In addition, Maryland's Office of Cybersecurity (OC) submitted a status update on DERs and DER aggregators. The report acknowledged non-consensus issues, while offering several recommendations: (1) improving the DER aggregator licensing process via a revised license to operate application; (2) revising state regulations to reflect cybersecurity baselines established by the National Association of Regulatory Utility Commissioners (NARUC) and the U.S. Department of Energy, OC's proposed enforcement mechanisms, and OC's proposed language addressing critical security controls; (3) delegating compliance to the utilities with willingness from the PSC; (4) further study of DER and VPP cybersecurity investigation by the PSC; and (5) considering regulating DERAs as public service companies and formally classifying them as critical infrastructure.

The PSC discussed the conceptual reports at a technical conference in December 2025.

State Rules | Utility Storage or Multi-Technology Program (Case 9761 - *pending*)

In July 2024, the Maryland Public Service Commission (PSC) launched a proceeding to implement Maryland's DRIVE Act, inviting comments on incentives or amendments needed to expand integration of distributed renewables. In October 2024, the PSC issued an order allowing (but not requiring) utilities to offer incentives for distributed renewable assets that specifically include support for income-qualified households. The PSC also directed Staff to propose amending curtailment service provider regulations to include distributed renewable assets to facilitate market participation in PJM Interconnection, as described in FERC Order 2222.

In January 2025, the PSC clarified that incentives for any technology (i.e., not only solar and energy storage) beneficial to VPPs may be included in utility proposals, and that regulatory assets may not be used for incentive programs. In April 2025, the PSC directed Staff to consult with stakeholders to further develop a DER license proposal that meets the needs of the DRIVE Act and other DER aggregations in Maryland, and to recommend a code of conduct for DER aggregators. The PSC approved the license and application two months later.

In July 2025, BGE, Potomac Edison, and Delmarva and Pepco (jointly) filed proposals for VPP programs:

- BGE's proposed VPP pilot would target and enroll existing and new residential BTM DERs, with a specific focus on stationary energy storage devices and customer EVs with bidirectional capability. Solar-plus-storage installations would receive a higher incentive payment to comply with the intent of the DRIVE Act.
- Delmarva's and Pepco's (jointly) proposed Distribution System Support Services (DSSS) pilot program (essentially a VPP program) would offer connectivity and performance-based incentives for EVs with bidirectional charging capability and stationary battery storage devices, to provide grid services.
- Potomac Edison's proposed pilot targets existing and new bidirectional-capable residential EVs and battery storage. It would provide an annual participation incentive and a performance-based incentive of up to $300/kW-year.

In October 2025, the PSC denied the utilities' VPP proposals, directing each utility to file a revised proposal that incorporates the following directives:

- Increase the scale of the VPP pilots beyond the minimum requirements; if prerequisite technology like DERMS is necessary for scaling, then the utility must explain why a lack of these technologies would limit the scale.
- Allow third-party aggregators and C&I customers to participate, while expanding eligible technologies by providing a DR pathway, particularly for non-residential customers and aggregators.
- Allow customers to use device-level metering, including inverters, EV chargers, or battery management systems.
- Allow systems, including EVs, to inject into the grid, and include a pathway for vehicle-to-grid demonstrations.
- Include locational value in compensation.
- Limit pilots to two years (instead of three), with an extension possible, while establishing a pathway to transition to a permanent program.

The PSC stated that it will consider utility-owned devices only in the specific use case of non-wires solutions that cannot be provided by a third party or to promote equitable participation.

Utility Managed Charging Program (Case 9478 - *pending*)

In July 2025, the Maryland Public Service Commission (PSC) allowed Potomac Edison to extend two of its existing Phase I EV programs until the utility’s Phase II proposal is approved or until December 31, 2025, whichever is earlier. In August 2025, the PSC allowed BGE, Pepco, and Delmarva to continue operating certain Phase II EV programs while awaiting the outcome of proposed Phase II EV programs. Utilities subsequently requested additional extensions of Phase I EV programs, including Pepco’s Smart Charge Management (SCM) pilot.

In October 2025, the EV Workgroup submitted a report on the efficacy and appropriateness of different EV load-management options and incentive structures. Parties supported the continuation of both the SCM and TOU programs. The OPC recommended lower SCM incentive credits for customers who use both TOU and SCM. Staff and utilities oppose limiting a customer's incentive based on the utilization of a TOU rate. Parties support the development of a data collection and cost benefit analysis at the midpoint and conclusion of the Phase II programs, if SCM and TOU are approved. In December 2025, the PSC decided that for any Phase I pilot programs whose authorizations expire on December 31, 2025, authorization is extended until January 31, 2026, or until the PSC issues an order on Phase II proposals.

Massachusetts

Investigation (Grid Services Study - *completed*)

In 2024, the Massachusetts Clean Energy Center recruited a consultant (E3) to develop a state-specific, statewide compensation mechanism for DERs that provide services to the state's grid, and to develop an implementation roadmap to maximize long-term DER adoption and participation. E3 completed the roadmap report, “DER-riving Local Value," in September 2025. The report defines "grid services" as the use of organically deployed DERs to reduce distribution system costs relative to traditional solutions. DERs could provide grid services by deferring infrastructure investments and providing flexible capacity to mitigate local reliability risks that cannot be resolved through traditional infrastructure solutions. The report includes 10 key findings:

- Distribution grid services require location-specific mechanisms that focus on the bulk system value.
- Infrastructure deferral can deliver benefits via quantifiable savings for customers and hard-to-quantify benefits for impacted communities.
- DERs can offer bridge-to-wires support where infrastructure upgrades are delayed, and need is immediate.
- DERs’ benefits should be categorized by impact on utility revenue requirement and rates.
- Compensation should be capped by the net reduction in revenue requirement that the grid services provide.
- Encouraging DER participation requires compensation to exceed the opportunity cost for forgoing other revenue opportunities.
- Dispatch signals across all DER programs should be coordinated.
- Offerings should utilize a comprehensive approach to support equity and environmental justice.

- Offerings will be most effective without a one-size-fits-all approach.
- The long-term value will be maximized by iterative information improvement and "learning by doing" in the near-term.

The report's evaluation framework uses three criteria to determine the value of a grid service: (1) a capacity constraint scenario, (2) a rate impact value stream, and (3) a non-rate impact value stream. Under the first criterion, the two options are deferring infrastructure investments and bridges-to-wires. "Other" impact value streams may be assessed in the future, when better data and quantification methods are available; examples include optionality, accelerated interconnections, or avoided construction-related impacts.

Utility Managed Charging Program (Docket 24-195 - *decided*)

In December 2024, Eversource filed modifications to its EV Infrastructure Program, including a new managed charging incentive. The residential managed charging program would provide an off-peak passive reward and enrollment incentive for participating customers, in addition to scheduled active managed charging offered by invitation only as a complimentary service to those who routinely miss the off-peak target. The utility will offer an off-peak rewards program through which customers will receive $10/month for participating if 90% of the charging occurs outside the peak demand periods. Customers would also receive a $50 enrollment incentive. The Massachusetts Department of Public Utilities filed an order in October 2025, approving the program.

Minnesota 

Planning & Procurement (Docket 24-67 - *decided*)

In February 2024, Xcel Energy filed its 2024-2040 Upper Midwest Resource Plan for its service territories in Minnesota, Wisconsin, Michigan, South Dakota, and North Dakota. Within the plan, Xcel included a proposed Distributed Capacity Procurement (DCP) process – in essence, a utility-owned, utility-operated VPP – to integrate DERs into its resource plan. The DCP initiative could procure 400 MW to more than 1 GW of DERs, depending on system needs. With a theoretical target of 400 MW storage and 440 MW solar, the DCP could launch within nine to 12 months and deploy within 36 months.

Under a joint settlement agreement filed in October 2024, Xcel committed to propose its DCP initiative in 2025. The Minnesota Public Utilities Commission approved the settlement in April 2025.

Planning & Procurement (Docket 25-378 - *pending*)

In October 2025, Xcel Energy proposed Phase 2 of its DCP initiative (see Docket 24-67), deemed Capacity*Connect (C*C); Phase 1 focused on research and development. C*C would deploy approximately 50 MW to 200 MW of utility-owned, utility-operated FTM battery storage by the end of 2028. Xcel would also implement a limited deployment of DERMS to support C*C. Its stated objective is to provide capacity and energy benefits to customers without requiring major interconnection, upgrades, and investment in the bulk system. Xcel would identify eligible feeders via a multi-step analysis. The proposed program budget ranges from $152 million (for 50 MW) to $430 million (for 200 MW) through 2028, with costs recovered via Xcel's Renewable Energy Standard Rider.

Utility Managed Charging Program (Docket 25-377 - *pending*)

In October 2025, Otter Tail Power proposed a new EV Credit Rider and corresponding tariff. The rider would offer an additional option to EV customers interested in participating in the utility's demand control program. It would be available to customers on the Standard Residential Rate or Farm Rate, and with a hardwired Level 2 EV charger installed at their residence, connected to a whole-home meter instead of a secondary EV-only meter. Otter Tail would then connect a load control switch to the EV charger, so it could remotely control charging. Participants must agree to up to 12 hours of controlled service within a 24-hour period, with most periods lasting one to three hours (or longer periods under MISO emergency conditions). Due to technical limitations, participants could not opt out of events. Participants would receive a monthly credit of $9 for a single charger and $13 for multiple chargers.

Missouri

Utility Demand Response Program (Docket EO-2025-0124 - *decided*)

In January 2025, Liberty Utilities filed its Missouri Energy Efficiency Investment Act (MEEIA) proposal, which includes a residential DR program making use of smart thermostats (available to all customers with direct control of their HVAC system) and a C&I DR program. These new programs would replace the utility's existing programs. A stipulation filed in March 2025 supported the residential and commercial programs as proposed, but subsequent concerns regarding the stipulation led Liberty to withdraw its proposal.

Nevada

Utility Demand Response Program | Utility Storage or Multi-Technology Program (Docket 25-10012 - *pending*)

In October 2025, Nevada Power proposed to update its Optional Load Management and Automation Services Rider (Schedule OLM-AS), and to establish a new Energy Grid Services Rider (Schedule GSR-E) and Capacity Grid Services Rider (Schedule GSR-C), to support DR programs and broader load-flexibility programs approved in Docket No. 24-05041. Originally approved in 2011, Schedule OLM-AS provides the contractual backing for DR and load management communication device lending by Nevada Power. The proposed revisions to Schedule OLM-AS incorporate the new Schedule GSR-E and Schedule GSR-C programs.

Schedule GSR-E would provide an energy credit (based on the avoided cost of energy) to customers during load flexibility events. The calculation used a customer-specific baseline to determine a "counterfactual," referring to what the energy consumption profile of the customer most likely would have been in the absence of an event. This baseline profile is compared to actual usage during an event, to determine the difference in energy utilization, deemed "event energy." This "event energy" is multiplied by an adjusted market rate based on wholesale energy costs, plus a locational distribution adder. Schedule GSR-E is technology-agnostic; it could support multiple customer classes and DER types.

Schedule GSR-C would provide a capacity credit equivalent to the capacity avoided (or provided from an energy storage device) during load flexibility events. Credits are calculated considering performance across multiple load flexibility events. Schedule GSR-C also uses a customer-specific baseline and measured energy to determine changes in the customer's energy utilization profile. This method is used to determine "event capacity" for specific events and to determine "annually qualified capacity," which represents performance across all events.

Utility Demand Response Program | Utility Storage or Multi-Technology Program
(Docket 25-10013 - *pending*)

In October 2025, Sierra Pacific Power proposed to update its Optional Load Management and Automation Services Rider (Schedule OLM-AS), and to establish a new Energy Grid Services Rider (Schedule GSR-E) and Capacity Grid Services Rider (Schedule GSR-C), to support DR programs and broader load-flexibility programs approved in Docket No. 24-05041. Originally approved in 2011, Schedule OLM-AS provides the contractual backing for DR and load management communication device lending by Sierra Pacific Power. The proposed revisions to Schedule OLM-AS incorporate the new Schedule GSR-E and Schedule GSR-C programs.

Schedule GSR-E would provide an energy credit (based on the avoided cost of energy) to customers during load flexibility events. The calculation used a customer-specific baseline to determine a "counterfactual," referring to what the energy consumption profile of the customer most likely would have been in the absence of an event. This baseline profile is compared to actual usage during an event to determine the difference in energy utilization, deemed "event energy." This "event energy" is multiplied by an adjusted market rate based on wholesale energy costs, plus a locational distribution adder.

Schedule GSR-C would provide a capacity credit equivalent to the capacity avoided (or provided from an energy storage device) during load flexibility events. Credits are calculated considering performance across multiple load flexibility events. Schedule GSR-C also uses a customer-specific baseline and measured energy to determine the change in the energy utilization profile of the customer. This method is used to determine "event capacity" for specific events and to determine "annually qualified capacity," which represents performance across all events.

New Hampshire

Utility Storage or Multi-Technology Program (Docket DE 23-039 - *decided*)

In March 2025, the New Hampshire Public Utilities Commission approved a settlement agreement filed in Liberty Utilities' 2023-26 general rate case, initiated in 2023. Although Liberty Utilities proposed expanding its existing battery storage programs and creating a new BYOD program, the settlement does not specifically address the proposed BYOD program. However, as specified in the settlement, Liberty will continue to use its existing TOU model to establish rates for its battery storage program.

New Jersey

Investigation (Docket EO24020116 - *pending*)

In March 2024, the New Jersey Board of Public Utilities (BPU) requested information from utilities and other stakeholders interested in wholesale market participation of DERAs under FERC Order 2222. Questions posed to utilities addressed how they are preparing for DERA, including specific processes under development, concerns about grid reliability for DERA not addressed thus far by PJM or the BPU, what processes utilities use to account for or support new DER technologies, cybersecurity or telemetry concerns, and pilot program plans. Questions posted to other stakeholders addressed concerns about dispute resolution, technical support needs, pilot program information, and performance tracking and monitoring. The BPU held a related technical conference in January 2025.

State Rules (Docket QO25050300 - *pending*)

The New Jersey Clean Energy Act of 2018 established a redesign of the state's energy efficiency and peak demand reduction (EE and PDR) programs, arising from state-level EE and PDR goals. The EE and PDR programs are updated on a three-year cycle. In November 2025, the New Jersey Board of Public Utilities issued a straw proposal for a regulatory framework, to which each electric and gas utility will propose EE and PDR programs for the third three-year cycle of programs (Triennium 3).

The third focus area in Triennium 3 is to advance DR programs beyond direct load control (DLC) programs offered in Triennium 2, and to deploy infrastructure to allow scaling DR growth. The near-term DR goal of Triennium 3 is to transition from the closed DLC and pilot programs of Triennium 2 to an initially closed wholesale and retail market of DR (e.g., connected devices and contracts with third parties) supported by a third-party ecosystem.

Furthermore, the DR programs in Triennium 3 would leverage AMI investments to capture peak reductions from DERs, support development of grid services by deploying DR resources, develop data systems that would lay a foundation for tracking and coordinating DER aggregations in PJM wholesale markets, and support DR goals through performance-based contracts with third-party providers using participant incentives. The regulatory framework includes a DR roadmap and requirements for each utility's proposed DR program narrative, program implementation and metrics, a narrative detailing plans to leverage time-varying rates and AMI, and a narrative describing the approach to developing and utilizing a third-party DR ecosystem.

New Mexico

Wholesale Market Participation (Docket 24-00259-UT - *decided*)

In October 2024, Xcel Energy proposed a Southwest Power Pool Integrated Marketplace (SPP IM) Demand Response Option Tariff, having proposed a similar tariff in Texas two months earlier (Docket 56921). Anticipating a capacity shortfall in 2027, Xcel proposed to counter it with near-term voluntary DR options via SPP participation. The proposed tariff and corresponding standard customer agreement would offer a new pilot interruptible program for large general transmission customers. Participants could bid their load into the SPP IM as a DR resource; if chosen, the participant must interrupt the load when requested by SPP.

In February 2025, Xcel filed a stipulation that would approve its proposed SPP IM tariff, with modifications. Key revisions include: (1) Xcel would allow customers to segregate interruptible load through the use of additional meters; and (2) participating customers would be credited 75% of the net revenue, with the remaining 25% allocated to Xcel for administration costs. The New Mexico Public Regulation Commission approved the stipulation in June.

State Rules (H.B. 13 - *failed to pass*)

H.B. 13 passed New Mexico's House but died in the state's Senate. H.B. 13 would have required utilities to file triennially with the New Mexico Public Regulation Commission (PRC) distribution system plans that include:

- Detailed mapping of distribution hosting capacity, available load capacity, and underlying data;
- Proposed reasonable average and maximum target energization time periods, along with a record of recent energization time periods for various customer rate classifications and voltage service levels;
- A proposed per-kW interconnection fee for new residential distributed generation customers;
- Optional flexible interconnection or energization tariffs;
- A plan to use DERs to avoid or minimize the need for traditional distribution system upgrades; and
- A 10-year planning horizon with a five-year budget.

H.B. 13 also would have required the PRC to adopt rules for a VPP program, with eligible DERs specified. The bill directed the PRC to:

- Establish annual cost-effective capacity procurement and performance targets;
- Consider how a VPP program would interact or complement other programs;
- Require a tariff establishing performance requirements and performance-based compensation for VPP program that vary by DER, and allow customers to opt out of events that exceed participation requirements;
- Prescribe method(s) for setting performance-based compensation that reflect the full value of grid services;
- Allow both third parties and utilities to serve as DER aggregators, while ensuring that utilities do not have a competitive edge over third parties;

- Ensure potential participants are not disqualified if they receive other incentives distinct from the VPP program; and
- Consider operational, reliability, or market guidelines and requirements established by FERC and the New Mexico Renewable Energy Transmission Authority.

New York

Investigation (Docket 24-E-0165 - *pending*)

The New York Public Service Commission (PSC) launched the "Grid of the Future" proceeding in 2024 to help achieve the state's renewable energy goals through flexible resources. The first phase of this initiative involved a grid flexibility study, which: (1) assesses current and future potential capabilities of flexible resources across the state's grid; (2) identifies near-term actions to increase the deployment and use of flexible resources, while improving the integration of these resources into planning and grid operations; and (3) serves as a foundation for the New York Grid of the Future Plan.

In January 2025, the New York Department of Public Service (DPS) completed the Grid Flexibility Study Phase 1 report, finding that: (1) the state's 2040 grid flexibility potential is more than six times its current capacity, amounting to more than 8 GW; (2) all modeled grid flexible options are cost-effective in 2040; (3) by 2040, grid flexibility could avoid nearly $3 billion per year in power system costs; and (4) a lack of performance data and advanced software/forecasting capabilities make it difficult for planners to estimate whether there is enough flexibility potential in specific locations that would be suitable for near-term grid needs.

In March 2025, the DPS completed the first iteration of the Grid of the Future Plan. The Plan uses insights from the Grid Flexibility Study to guide the development of a more expansive distributed system implementation plan (DSIP) aligned with the goals of the proceeding. (DSIPs are biannual filings by utilities reporting on the implementation of a distributed system platform.) The Plan includes recommendations to better align DSIP guidance with the state's climate goals, including: (1) clarifying recommended guidance to elicit more consistent and clear responses; (2) standardizing the format of prompts; (3) reorganizing and streamlining technical topic areas to better reflect the needs of a distribution system platform; and (4) ensuring that future DSIPs focus on the value of processes and activities and specific metrics to track progress towards achieving a fully functioning distributed system plan. The Plan also proposes developing utility-specific priorities to encourage the development of various capabilities.

State Storage or Multi-Technology Program (Docket 18-E-0130 - *decided*)

In 2018, the New York Public Service Commission (PSC) adopted an energy storage target and roadmap for deploying 1.5 GW of storage by 2025 and 2 GW by 2030. In 2024, the PSC approved a framework to achieve an expanded 2030 target of 6 GW. In January 2025, NYSEG and RG&E issued RFPs for vendors with the capability to deliver dynamic load management (DLM), including load-relief solutions.

In February 2025, the PSC approved NYSERDA's 2024-2030 Residential and Retail Storage Implementation Plan, with modifications. The original plan describes NYSERDA programs that will help procure 200 MW of residential storage and 1.5 GW of commercial storage by 2030, as a part of New York's 2030 goal. The MWh Block program will continue, with additional residential and retail capacity. The plan outlines one new block for each sector and region, while leaving room for future blocks. The modifications include a requirement for residential storage projects that receive a program incentive to participate in the relevant DLM program for the project's location (if such a program is available), and clarification that NYISO DER Aggregation program participants may participate in the retail storage program. NYSERDA filed a revised implementation plan in April 2025.

Utility Managed Charging Program (Docket 22-E-0236 - *pending*)

The New York Public Service Commission (PSC) opened this proceeding in 2022 to establish alternatives to traditional demand-based rate structures for commercial EV charging. In August 2024, the PSC approved, with modifications, a new incentive program – the Load Management Technology Incentive Program (LMTIP) – proposed jointly by New York's investor-owned utilities. The PSC directed the utilities to collaborate on deployment and implementation, using consistent technology eligibility statewide and establishing a shared program webpage. Demand Charge Rebate, Commercial Managed Charging Program (CMCP), Phase-In EV Rate, Light-Duty Make-Ready, and Medium- and Heavy-Duty Pilot customers may participate in the LMTIP. In July 2025, the utilities filed a revised LMTIP in accordance with the PSC's August 2024 order.

In September 2025, upstate utilities requested revisions to a proposed CMCP they previously submitted. These revisions include a revised calculation of the peak avoidance incentive, the elimination of an off-peak charging incentive (in order to improve the program's administration and avoid negative volumetric rates), and the use of a phased enrollment strategy.

Utility Storage or Multi-Technology Program (Docket 17-E-0104 - *pending*)

In 2024, the New York Public Service Commission (PSC) ordered utilities to propose a residential Bring Your Own Battery (BYOB) program, allowing for the inclusion of energy storage in their direct load control (DLC) programs, within their annual DR filings. National Grid, New York State Electric & Gas (NYSEG), Rochester Gas & Electric (RG&E), and Orange & Rockland (O&R) proposed to extend their DLC programs to include BYOB programs. Consolidated Edison (ConEd) did not propose a program, while Central Hudson Gas & Electric indicated that further analysis was required. In January 2025, NYSEG and RG&E issued RFPs for vendors with the capability to deliver Dynamic Load Management (DLM), including load relief solutions commencing in the 2026 capability period. In April 2025, the PSC approved 2024 proposals by National Grid, NYSEG, RG&E, and O&R to implement a DLC energy storage program, while directing ConEd and Central Hudson to submit proposals for such programs.

North Carolina

Utility Demand Response Program | Utility Storage or Multi-Technology Program (Dockets E-7 Sub 1032, E-2 Sub 931 - *pending*)

In September 2025, Duke Energy Carolinas and Duke Energy Progress proposed a new Non-Residential Storage Demand Response Program, as required by a 2024 North Carolina Utilities

Commission (NCUC) order approving the utilities' residential PowerPair program. Similar to PowerPair, the new program would:

- Provide incentives to non-residential customers who dispatch their systems during called events, with participants agreeing to a minimum dispatch amount within their contract.
- Events would last four hours, with advance notification; approximately 30 to 36 events would be called annually (in both summer and winter).
- Participants would receive a one-time $120/kW enrollment incentive; systems that are charged at least 25% by a connected PV system would receive an additional $30/kW.
- Participants would receive a monthly $3.50/kW capacity credit (adjusted by a capability factor) during enrollment; during months with called events, they would also receive an energy credit of $0.10/kWh dispatched.
- Customers could opt out of up to four events per year (two in summer, two in winter). If a customer does not meet the minimum contracted dispatch, there is no penalty, but repeated failures can trigger an administrative review and result in forfeiture or clawback of incentives or removal from the program.
- If a customer leaves the program before three years of participation, the customer would forfeit the capacity credits for the remainder of that year, and they may forfeit 33% of the enrollment incentive for the remaining years.

In November 2025, Public Staff recommended approving the application.

Within these proceedings, Duke Energy Carolinas and Duke Energy Progress also proposed to modify their existing non-residential DR program, PowerShare. The utilities proposed the addition of 10- and 120-minute notification windows to the program's Mandatory Curtailment option (in addition to the existing 30-minute notification window). They also proposed allowing participants to automate their load curtailment through a utility-supplied controller. At the time, program participation relied on customers to modify their operations in order to comply. The NCUC approved the modifications to the PowerShare program in November 2025.

Ohio

Utility Demand Response Program (Docket 24-0046-EL-ATA - *withdrawn*)

In January 2024, Duke Energy Ohio proposed its 2024-2026 energy efficiency and DSM portfolio. The proposed programs include a residential load-control program that would utilize residential air conditioners during peak-demand periods. Duke Energy subsequently withdrew its application; the Public Utilities Commission of Ohio granted the withdrawal in October 2025.

Oregon

Planning & Procurement (Docket UM 2362 - *decided*)

In December 2024, Portland General Electric (PGE) filed its 2024 Distribution System Plan (DSP), which includes planned investments into traditional infrastructure, grid modernization, and VPP resources over the next two to four years. The VPP investments would focus on flexible load, solar-plus-storage, and distributed thermal, amounting to 1,021 MW and 937 MW for summer and winter, respectively, in 2029. The Oregon Public Utility Commission approved PGE's DSP in October 2025.

Utility Demand Response Program ([Docket ADV 1659]() - *decided*)

In October 2024, Idaho Power proposed modifications to two of its DR programs, Irrigation Peak Rewards (Schedule 23) and Flex Peak Program (Schedule 76). It filed similar modifications in Idaho in late September 2024 (see Docket IPC-E-24-37). The proposed modifications to Schedule 23 would:

- Add an early-interruption option, under which events last no later than 9 p.m.
- Permit participants to utilize the manual dispatch option to allow time between when service locations are dispatched.
- Add clarifying language around emergency dispatch to the uniform irrigation peak rewards service application.

The proposed modifications to Schedule 76 would:

- Reimburse participants who choose to automate their systems with load-control devices;
- Update how adjusted baseline caps are calculated on event days;
- Allow day-of-adjustment modifications for instances where a participant initiates a partial or complete shutdown of their facility site during the day of a load control event; and
- Add flexibility to the nomination process.

Idaho Power also proposed to revise the threshold for the variable incentive payment for both programs (i.e., from beginning on the fifth event to beginning on the fourth event). The Oregon Public Utility Commission approved the proposed revisions in January 2025.

Utility Demand Response Program ([Docket ADV 1708]() - *decided*)

In February 2025, Pacific Power proposed a new DR program, the Cool Keeper Program, using the provisions of its existing DR programs (Schedule 106). Under the new program, Pacific Power would install load-control switches on the compressor unit of residential and small commercial air-conditioning and heat pump systems to enable aggregated use of this load for grid management. For allowing periodic curtailment of power for a maximum of four hours per day, from May to September (for up to 100 hours per year), participating customers would receive a monthly bill credit. All dispatches will be instantaneous, without customer notification; however, the customer's thermostat and air conditioner fan will continue to operate during a dispatch. The Oregon Public Utility Commission approved the program in May.

Utility Demand Response Program ([Docket ADV 1719]() - *decided*)

In April 2025, Portland General Electric (PGE) proposed revisions to several of its DR tariffs, including: Multifamily Residential Demand Response Water Heater Pilot Rider (Schedule 4); Direct Load Control Pilot Rider - Residential Smart Thermostats (Schedule 5); Residential Service - Peak Time Rebates (Schedule 7); Nonresidential Direct Load Control Pilot - Energy Partner Thermostats (Schedule 25); and Nonresidential Demand Response Program (Schedule

26). PGE's request would:

- Align programmatic language around holidays and add flexibility to event dispatching requirements for all schedules;
- Extend the duration of the pilot terms for Schedules 4 and 25, while removing the pilot status from Schedules 5 and 7;
- Allow PGE to call events outside of defined seasons or holidays;
- Extend the expiration date for Schedules 4 and 25 pilots to December 31, 2027;
- Allow Schedule 5's pilot to expire June 30, 2025; and
- Eliminate the pilot status of Schedule 5 and 7 (which PGE has deemed mature and cost-effective).

The Oregon Public Utility Commission approved PGE's requested revisions in May 2025.

Utility Demand Response Program (Docket ADV 1776 - *decided*)

In August 2025, Portland General Electric (PGE) filed a proposal to modify its BYOT Program. Specifically, PGE requested permission to administer an additional one-time enrollment incentive of $25. PGE proposed these revisions because certain smart thermostats will no longer be supported by their manufacturer, and PGE would no longer be able to communicate with such devices for DR events. This proposal will allow an additional one-time enrollment incentive for customers impacted by these changes and encourage customers to purchase a new qualifying thermostat and re-enroll in the program. The Oregon Public Utility Commission approved the revisions in September 2025.

Utility Demand Response Program (Docket ADV 1792 - *decided*)

In October 2025, Portland General Electric (PGE) filed a request to modify its Multifamily Residential Demand Response Water Heater Pilot. PGE requested to reopen the pilot to new enrollment and to extend the pilot period. The existing program closed to new participants after July 2023, while the pilot would continue until December 31, 2027. The modifications would allow the pilot to remain open to new participants after November 14, 2025, with no clear enrollment period or pilot end date. In November 2025, the Oregon Public Utility Commission approved the modifications.

Utility Managed Charging Program (Docket ADV 1720 - *decided*)

In April 2025, Portland General Electric (PGE) requested revisions to its Residential EV Charging Pilot (Schedule 8) in order to extend the end date for enrollment (through the end of 2025), to remove the prescriptive event dispatch group strategy and composition, and to align the holiday schedule with PGE's DR tariffs. The Oregon Public Utility Commission approved PGE's requested revisions in May 2025.

Utility Managed Charging Program (Docket ADV 1723 - *decided*)

In April 2025, Pacific Power proposed a new Transportation Electrification Managed Charging Pilot (Schedule 120), following the Oregon Public Utility Commission's (PUC) approval (in 2023) of the initial proposal and outline for Schedule 120 within the utility's 2023 Transportation Electrification Plan. The three-year pilot would offer participants an incentive based on the length of enrollment and the number of managed charging events they opt out of, in addition to a potential one-time enrollment credit. The PUC approved Pacific Power's program in May 2025.

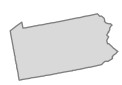
Utility Storage or Multi-Technology Program (Docket ADV 1691 - *decided*)

In December 2024, Pacific Power proposed to create a new program – Wattsmart Battery – under the provisions of its existing DR programs (Schedule 106). (PacifiCorp utilities in other U.S. states have operated similar programs since 2020.) The program would incentivize the installation of new batteries for residential and commercial customers. Participants would receive an enrollment payment of $150/kW multiplied by the commitment term (up to four years). This incentive would be capped at 70% of battery equipment costs. Participants would also receive an annual $15/kW incentive during the commitment term and an annual $50/kW if they continue to participate beyond the four-year commitment term. Pacific Power could dispatch batteries (by up to 90%) without advanced notice. The Oregon Public Utility Commission approved Pacific Power's program in February 2025.

Utility Storage or Multi-Technology Program (Docket ADV 1797 - *decided*)

In October 2025, Portland General Electric (PGE) requested to extend (again) the expiration date of its existing Battery Energy Storage Pilot (Schedule 14) by one year – to December 31, 2026 – so that PGE may continue to pursue and understand advanced grid services under the pilot, prior to proposing a new program in September 2026. (This pilot was previously scheduled to expire on July 31, 2025.) In December 2025, the Oregon Public Utility Commission approved the extension.

Pennsylvania



Utility Storage or Multi-Technology Program (Docket P-2024-3049223 - *pending*)

In May 2024, PPL Electric filed its second Distributed Energy Resources Management Plan. Among other things, PPL's proposed plan includes converting an existing pilot for utility management of customer DER assets into a permanent program, while expanding the program's scope to include devices installed before the pilot began (in January 2021) and other inverter-based DERs with no management devices presently installed. PPL's petition also contains proposed tariff updates with smart inverter settings and requirements, as well as specifications for DER management devices. In June 2025, an administrative law judge (ALJ) concluded that the utility had not met its burden of proof and recommended that the Pennsylvania Public Utility Commission (PUC) deny PPL's petition.

In December 2025, the PUC issued an order granting in part and denying in part exceptions filed by PPL in response to the ALJ's ruling. Overall, the PUC declined to adopt the ALJ's recommendation in full and instead approved the plan, with modifications:

- The PUC granted PPL's Exception No. 1, which contends that the ALJ erred in finding that PPL did not demonstrate why the scope of its proposed active monitoring and control of DER devices is reasonable or necessary. Further, it stated that utilities and

regulators should consider the opportunity to utilize certain functions before achieving higher penetration of DERs, and that the continued and unmonitored deployment of DERs presents grid and distribution system challenges.
- PPL's Exception No. 2 contended that the ALJ improperly found that PPL's requirements for interconnecting DERs have resulted in credible harm to the Joint Solar Parties (JSPs). The PUC found that Exception No. 2 should be granted with the modification that PPL is directed to conduct an RFP for third-party aggregators to ensure that PPL's plan does not result in blocked or limited market entry for third-party aggregation for DERs.
- PPL's Exception No. 3 objected to the ALJ's conclusion that the utility's cost-benefit analyses do not support the plan. The PUC found that Exception No. 3 should be granted because PPL's cost-benefit analysis met the burden of proof and showed a reduced revenue requirement that could apply downward pressure on customer rates.
- PPL's Exception No. 4 requested that the PUC direct reasonable modifications to the plan rather than outright reject it. The PUC found that Exception No. 4 should be granted in part, with the requirement that PPL file a DER orchestration plan and an evaluation of three different flexible interconnection approaches.

Later in December 2025, multiple parties filed petitions for reconsideration or clarification:

- The Office of the Consumer Advocate (OCA) requested that the PUC reconsider and/or clarify its final determination in its order. The PUC approved the OCA's request to direct PPL to file an orchestration plan, but it did not address OCA's request that devices under 200 kW be excluded.
- The JSPs requested that the PUC stay its final order pending an appeal filed by the JSPs, and to bar PPL from conditioning DER interconnection on PPL testing to ensure customer-owned DERs are compatible with PPL-owned DER management devices if its petition is ultimately denied. The JSPs also requested that the PUC clarify that the DER orchestration plan and RFP for third-party aggregation are required before submitting a revised petition for approval of a Second DER Management Plan.

The PUC subsequently issued a "tolling order" granting these petitions, pending further review and consideration of the merits.

Wholesale Market Participation (Docket L-2023-3044115 - *pending*)

In February 2024, the Pennsylvania Public Utility Commission (PUC) solicited stakeholder comments on actions, additions, or amendments to rules and regulations to support the implementation of FERC Order 2222 (which thus far has occurred largely via PJM's FERC tariff filings, with processes to be executed by utilities). The PUC is considering input on DERAs (i.e., VPPs) as a potential mechanism to increase efficiency, improve service, and lower costs. It is also considering revisions to DER interconnection rules, metering requirements, interconnection cost allocation, distribution utility responsibility and DER management, small utility opt-in procedures, cybersecurity concerns, VPP benefits, billing issues, and equity concerns.

In December 2025, the PUC voted to advance proposed rules for the participation of DERAs in PJM (with an order formally filed in January 2026). The proposed rules outline regulations to apply to DER operators, DERAs, and utilities related to DERA participation in PJM markets. They would require larger utilities to allow DERA resource participation within their service territories under the conditions that: (1) customer-generators receiving service under a net metering tariff are precluded from participating as a DER aggregator resource in PJM capacity and energy markets, and (2) the component DER was granted relevant approvals by the utility to participate in PJM markets. Smaller utilities could allow DERA resource participation upon PUC approval. Utilities allowing DERA resource participation would be required to file a corresponding tariff with the PUC. The proposed rules would also set requirements for the review of component DER applications, including completion within 60 days and the possibility of establishing a fee. Finally, they would establish conditions for component DER operations, including data access rules and utility dispatch override conditions, as well as interconnection disputes.

Rhode Island

Utility Demand Response Program | **Utility Managed Charging Program** | **Utility Storage or Multi-Technology Program** (Docket 24-06-EE - *decided*)

In 2024, Rhode Island Energy filed its 2024-2026 System Reliability Procurement Investment Proposal, which includes a ConnectedSolutions DR program and three-year program budget. Existing participation pathways -- residential and small business BYOT, residential and small business battery, C&I targeted dispatch, and C&I daily dispatch -- would continue, with modified incentive levels. BYOT incentive levels would double; all other incentive levels would be lower.

Rhode Island Energy proposed a new residential and small business participation pathway (including incentives) for DR via active EV managed charging, as well as a PIM equaling 20% of total net avoided electric bill costs. Funds accrued via the PIM would support grid investments.

In March 2025, the Rhode Island Public Utilities Commission (PUC) posted an open meeting order (from July 2024) approving the implementation budget and PIM, but declining to rule on the program design or implementation details, instead leaving decisions to Rhode Island Energy. In April 2025, the PUC issued a formal order that upheld and clarified its open meeting order, while capping the program budget (due to concerns that the program might not provide a positive return on investment to participants) and revising the PIM formula.

South Carolina

State Rules (H.B. 3309 - *enacted*)

South Carolina enacted sweeping energy legislation (H.B. 3309) in May 2025, which, among other things authorizes utilities to propose programs and incentives to encourage the use of a wide variety of customer-sited DERs, to reduce consumption or demand, or to beneficially shape consumption or demand to reduce the utility's system or local coincidental peak demand, or reduce future utility system costs to serve its customers.

Utility Demand Response Program | **Utility Storage or Multi-Technology Program** (Docket 2024-303-E - *decided*)

In November 2024, Duke Energy Carolinas and Duke Energy Progress jointly proposed numerous revisions to their DSM programs. First, the utilities would modify their Equipment Control Rider – which provides incentives for customers to allow Duke to remotely control their HVAC systems, smart thermostats, and battery storage systems – by raising incentive levels for individual technologies and adding a new upfront incentive for new participants in the HVAC program. They also proposed creating a water heater control option and updating the months included within the different seasonal participation periods. Second, the utilities would modify their EnergyWise for Business Program (a DR program) by raising incentive levels and adjusting the months included within the seasonal participation periods. Third, they would revise their PowerShare Nonresidential Load Curtailment Program – which targets individually metered non-residential customers who can provide a minimum of 100 kW of load reduction – by raising incentive levels and creating a new curtailment option (Mandatory 50) targeting customers who can provide a minimum of 100 kW load reduction for up to 50 hours annually. The South Carolina Public Service Commission approved Duke Energy's proposed revisions in July 2025.

Texas

Wholesale Market Participation (Docket 53911 - *decided*)

In 2022, the Public Utilities Commission of Texas and ERCOT approved an Aggregate Distributed Energy Resource (ADER) Pilot, as proposed by the ADER Task Force. Under Phase 1 of the pilot, ADERs are treated as aggregate load resources under ERCOT's protocols, participating as security-constrained economic dispatch-dispatchable controllable load resources. (Phase 1 is limited to 80 MW, with no more than 40 MW providing non-spinning reserve services, along with limits for each load zone within ERCOT.) In 2024, ERCOT issued a revised governing document for Phase 2 of the program. Revisions include updated validation processes and allowing ancillary service ADERs to participate in ERCOT's Contingency Reserve Service (CRS). In June 2025, ERCOT issued a final Phase 3 governing document, which allows ADERs to provide ancillary services (including CRS and non-spin) using non-controllable load resources. It also raised the program capacity to 160 MW for energy, and to 80 MW for CRS and non-spin. In October 2025, ERCOT again raised the program caps to 200 MW and 100 MW, respectively.

Wholesale Market Participation (Docket 56921 - *decided*)

In 2024, Xcel Energy, anticipating a capacity shortfall in 2027, proposed a DR tariff for participation in the Southwest Power Pool (SPP). The new SPP Integrated Marketplace Demand Response Option (SPP IM) Tariff and corresponding standard customer agreement would offer a pilot interruptible program for large general transmission customers, under which participants could bid their load into the SPP IM as a DR resource. Xcel also proposed to amend its Interruptible Credit Option (ICO) tariff by removing the 200-MW cap on customer enrollment, clarifying that customers cannot dual-participate in ICO and other interruptible load programs, clarifying that participants bear the costs of metering upgrades, and introducing a standard tariff customer agreement. Xcel also proposed amending its general service tariffs to add a new Off-Peak Alternate Rider and corresponding standard customer agreement. Rider participants would allow Xcel to interrupt their power use during peak hours, in return for a discounted generation capacity charge.

In October 2025, the Public Utilities Commission of Texas (PUCT) approved a settlement that incorporates several key revisions to the ICO tariff: (1) the tariff will allow customers to segregate their load via submetering equipment; (2) contracts must be for at least one year, with automatic renewals; and (3) the winter/summer monthly credit rates are replaced with a year-round monthly credit rate.

The PUCT approved the new Off-Peak Alternate Rider as proposed, while approving and modifying the SPP IM tariff as follows: (1) the tariff will allow customers to segregate their load via submetering equipment; (2) customers may modify their bid parameters with 30 days prior notice to Xcel; and (3) customers will be credited for 75% of the net revenue received for market participation; Xcel will receive the remaining 25% (for program administration costs).

Vermont

Utility Storage or Multi-Technology Program (Docket 25-0719-TF - *withdrawn*)

In April 2025, Green Mountain Power (GMP) proposed a new Energy Storage Program for residential and small business customers in Zone 4 (one of GMP's four broad circuit zones), with initial deployment available until September 30, 2026. Participants would receive a customer-sited, GMP-owned energy storage system that could provide whole-home backup power, and would allow GMP to access and control the system in order to reduce power costs. Non-TOU customers would receive a credit for all metered kWh losses related to GMP's dispatch of the system. GMP requested authorization for up to $30 million for the program.

GMP withdrew its proposal in September 2025. The Vermont Public Utility Commission approved the withdrawal the following month.

Utility Storage or Multi-Technology Program (Docket 25-0948-PET - *decided*)

In May 2025, Green Mountain Power (GMP) proposed to invest an additional $32 million in support of its Energy Storage System Tariff (ESS program) in order to meet strong customer demand. Originally approved in 2020 and extended in 2022, the program is authorized through September 2026. The program allows residential and general service customers to lease energy storage equipment, provided they allow GMP to control the system. In August, the Vermont Department of Public Service (DPS) recommended limiting to $16 million GMP's request to support the program's continued growth, avoiding reimposing a cap on program enrollment, and ensuring that any further spending is reviewed with the benefit of updated information. In November 2025, the Vermont Public Utility Commission adopted the DPS's recommendations.

Virginia

State Rules (H.B. 2346 / S.B. 1100 - *enacted*)

Enacted in May 2025, H.B. 2346 and S.B. 1100 (both identical) required Dominion Energy Virginia to propose, by December 1, 2025, a pilot program that:

- Evaluates methods to optimize demand through various technology applications, including the establishment of VPPs
- Evaluates capacity needs and the ability of VPPs to provide grid services during peak demand
- Consists of aggregations of DERs totaling up to 450 MW, including DERs located in multiple geographic regions
- Includes both utility-owned and non-utility-owned DERs
- May utilize any existing or proposed DER programs as part of the pilot

By November 15, 2026, Dominion must propose a program tariff or tariff structure through which residential and non-residential customers may enroll, either directly or through an aggregator. The pilot program must conclude its initial phase by July 1, 2028, at which time the Virginia State Corporation Commission will review the results and evaluate the effectiveness of the pilot in providing grid services during peak demand.

In addition, Dominion must propose a program of at least 15 MW, incentivizing residential customers to purchase battery storage, as well as a broader electric school bus program by December 31, 2027.

Utility Demand Response Program | Utility Storage or Multi-Technology Program (Docket PUR-2024-00222 - *decided*)

In December 2024, Dominion Energy Virginia submitted its 2024 DSM Update for review and approval by the Virginia State Corporation Commission (SCC). The update included three proposed new programs: (1) a Non-Residential Distributed Generation Program, (2) a Non-Residential Curtailment Program, and (3) a Residential Battery Storage Pilot Program. In August 2025, the SCC approved Dominion's proposed Non-Residential Distributed Generation Program and Non-Residential Curtailment Program. However, because a new law – H.B. 2346, enacted in May 2025 (see above) – required Dominion to propose a pilot program to evaluate demand-optimization methods, including VPPs, by December 1, 2025, the SCC rejected the proposed Residential Battery Storage Pilot Program and instead referred it to a stakeholder process. When the stakeholder process concludes, Dominion must file a report alongside its proposed VPP pilot that describes the results of the stakeholder process.

Utility Managed Charging Program (Docket PUR-2025-0159 - *pending*)

In September 2025, Appalachian Power filed its proposed Transportation Electrification Plan, which includes broad details regarding two new programs that the utility plans to pursue in the near term. (Appalachian Power will provide full program details in its next base rate case.) First, the Residential Managed Charging Pilot would offer upfront rebates for the purchase of an EV charger, with higher rebate levels for income-qualified customers. The pilot would allow participants to choose between passive or active managed charging. Both options would provide a monthly incentive. If a passive charging customer charges on-peak three times in a month, the credit for that month would be forfeited. If a customer forfeits the credit three times in a year, the customer could be dismissed from the program. Second, the Commercial Charging Pilot would offer rebates per EV charger port for commercial customers who install Level 2 or direct-current fast charging for public use, fleets, workplaces, or multi-family dwellings in eligible areas. The incentive level varies by the type and location of equipment installed.

Utility Managed Charging Program | Utility Storage or Multi-Technology Program (Docket PUR-2025-00210 - *pending*)

In December 2025, Dominion Energy Virginia proposed its 2025 Demand Side Management Update, which includes a variety of DR and battery storage incentive programs. These programs would also become part of Dominion's VPP Pilot program, proposed in Docket PUR-2025-00211. Dominion's proposal includes:

- A Residential Battery Storage Pilot, which would offer an incentive for customers to discharge their battery system when called during peak demand, as well as at other times when doing so can support grid reliability and services. Participants would receive an enrollment incentive of $1,000 upon registering, plus a performance-based incentive of $50 per average kW across all events for ongoing use of their device during called events. Incentives – based on average performance across all events in each season – would be paid twice annually.
- A Residential Income- and Age-Qualified Battery Storage Battery Purchase Pilot would provide qualifying customers with a no-cost battery storage system.
- A Residential Income- and Age-Qualified Battery Storage Pilot Demand Response Pilot would provide a performance-based incentive of $50 per average kW across all events for ongoing use of their device during called events. Incentives – based on average performance across all events in each season – would be paid twice annually.
- A BYOD Aggregator Access Pilot would allow qualified aggregators to enroll residential, commercial, and industrial customers with eligible DER technologies, including EV chargers, smart thermostats, and water heaters, across the utility's customer segments. There are different incentive structures depending on who manages the devices.
- A Residential EV Managed Charging Pilot Program for both TOU and non-TOU customers would support charging-optimization strategies that consist of daily optimization, event-based optimization, and distributed optimization. The proposed design incorporates an optimization engine that will enable device-level load management by ingesting user preferences, program requirements, grid events, and device telemetry to develop optimized charging plans for every participant, balancing the needs of both the utility and customers.

Utility Storage or Multi-Technology Program (Docket PUR-2025-00211 - *pending*)

In December 2025, Dominion Energy Virginia proposed a VPP pilot program, as required by H.B. 2346 of 2025. The proposed pilot would aggregate DR and DSM programs for eligible customers via a DERMS that enables real-time visibility, communication, and control of DERs at scale. The pilot would enable third-party aggregators to participate through the programs Dominion has proposed in its 2025 Demand Side Management Update in Docket PUR-2025-2010 (see above), as well as Dominion's existing DR programs. The pilot phase would last 18 months, beginning in early 2027.

State Rules (H.B. 2413 - *failed to pass)*

H.B. 2413 passed both state houses but died after a gubernatorial veto in March 2025. H.B. 2413 would have revised the utility IRP process by, among other things, requiring IRPs to: (1) reduce load growth and peak demand growth through cost-effective DR programs that include the incorporation of such programs into VPP aggregation; and (2) include modeling scenarios that support dynamic pricing to shift energy use to off-peak, battery storage (both utility and distributed), VPPs that utilize aggregated DR or energy storage, and managed EV charging and vehicle-to-grid power. Furthermore, H.B. 2413 would have required utilities, when preparing an IRP, to systematically evaluate and potentially propose long-term distribution and transmission grid planning and grid transformation projects, including VPPs, DERMS, non-wire solutions, and battery storage systems.

Washington

Planning & Procurement (Docket UE-250731 - *pending*)

In September 2025, Puget Sound Energy (PSE) issued an RFP for distributed solar and storage. Regarding energy storage, PSE is seeking only battery systems (200 kW to 6 MW) that are either standalone or paired with solar. PSE will have direct control over the battery systems through its energy management system or via VPPs. Systems must be interconnected to PSE's distribution systems and commercially operable by the end of 2028. PSE will consider both power purchase agreements (PPAs) and ownership proposals. The RFP is designed to help PSE meet its goal of acquiring up to 61 MW of cost-effective battery storage by the end of 2028.

Planning & Procurement (Docket U-240281 - *decided*)

In 2024, Washington enacted legislation (H.B. 1589) requiring large combination gas and electric utilities to achieve annual DR and demand flexibility equal to at least 10% of winter and summer peak electric demand by January 1, 2027. The Washington Utilities and Transportation Commission (UTC) may require a higher target if it is deemed cost-effective, and it may accept lower-level achievement if the requirement is deemed neither technically nor commercially feasible during the applicable emissions reduction period. H.B. 1589 required the UTC to adopt rules to implement consolidated planning requirements that allow for an integrated system plan, as well as a cost test for emissions reduction measures achieved by large combination utilities.

In September 2025, the UTC adopted rules addressing integrated system plans, including requirements for utilities to achieve annual DR and demand flexibility, a cost test for the purpose of determining the lowest reasonable cost of electrification measures, assessment of DERs and electrification, and interim implementation targets.

Wisconsin

Investigation (Docket 5-EI-163 - *pending*)

In September 2024, the Wisconsin Public Service Commission (PSC) launched a review of distributed aggregation of retail customer resources, inviting comments addressing: (1) whether the PSC should take any measures related to the aggregation of retail customers while this investigation is pending, (2) the pros and cons of allowing aggregation of retail customers, (3) how the aggregation of retail customers should be structured, (4) how aggregated retail customers would be compensated, (5) steps the PSC should take to ensure that any new processes align with state law and MISO rules, including FERC Order 2222 compliance. In July 2025, the PSC invited comments on a memo it issued. The memo suggests that while aggregators have not posed major problems for utilities thus far, utilities might file tariffs to address the added administrative costs imposed by aggregators. It also states that the PSC may consider requiring utilities to provide descriptions of the communication method between the utility and aggregators. The PSC may also consider requiring aggregator tariffs to include customer data sharing safeguards, as well as aggregator registration requirements and a streamlined data-sharing process.

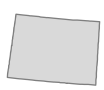
Utility Managed Charging Program (Docket 3270-TE-121 - *decided*)

In March 2025, Madison Gas & Electric (MGE) proposed to extend its Electric Vehicle Managed Charging Rewards (Charge Ahead) program – which was scheduled to expire in June 2025 – to January 1, 2026. (MGE plans to request a further extension and modifications to the program in a future rate case.) This program uses an app to connect to an EV to modify when the vehicle charges. Participants receive either a monthly incentive payment or benefits via a TOU rate. The Wisconsin Public Service Commission approved the extension in June 2025.

Wholesale Market Participation (Docket 4220-UR-127 - *decided*)

In March 2025, as part of a general rate case, Xcel Energy proposed adding to its DR tariffs language that would prohibit customers from participating in such programs if they participate in wholesale markets through an aggregator. In August 2025, the utility withdrew this aspect of the proposal from the request.

Wyoming



Utility Demand Response Program (Docket 17625 - *decided*)

In July 2024, Rocky Mountain Power (RMP) proposed a Demand Response Pilot Program (Schedule 114) for C&I customers for calendar years 2025-2029. Schedule 114 would be available to customers with loads greater than 500 kW that can be curtailed with no or limited advance notice. RMP would develop a custom site-specific DR strategy for each of the participating customers and their facilities. The program would run year-round, and events may be called at any time on any day of the week. Customers enrolled in either the real-time option or the advance notice option would receive \$100/kW to \$125/kW, while customers enrolled in both options could receive \$175/kW to \$190/kW, adjusted for capacity factor and event performance percentage. Event participation is voluntary, with no penalty for opting out. In May 2025, the Wyoming Public Service Commission approved a settlement agreement that established a four-year pilot period for Schedule 114.

Conclusion

VPPs offer opportunities for states and numerous stakeholders, including utilities, utility partners, DER aggregators, and utility customers. By providing this comprehensive annual report on the wide variety of approaches that states and utilities are pursuing to support VPP deployment, we hope that industry stakeholders will gain a better understanding of the possibilities, lessons, challenges, trends, and opportunities before them – and will be better positioned to develop their own policies and programs, if they choose to do so.

The primary authors of this report, Autumn Proudlove (afproudl@ncsu.edu) and Rusty Haynes (rhaynes@sepapower.org), welcome feedback on this publication and suggestions for future editions. SEPA and NCCETC plan to continue co-publishing quarterly blogs addressing state-level VPP developments.

NCCETC also publishes additional policy tracking reports through its DSIRE Insight platform; executive summaries of these reports are available here. SEPA frequently publishes research related to its primary focus areas, including VPPs and DERs; these public resources are available in SEPA's Knowledge Center.