NARUC
National Association of Regulatory Utility Commissioners

NASEO
National Association of State Energy Officials

Aggregated Distributed Energy Resources in 2024: The Fundamentals

RMI

July 2024

Acknowledgments

This document was prepared by RMI under contract with NARUC as part of the DER Integration and Compensation Initiative. It is based on work supported by the U.S. Department of Energy under Award Numbers DE-OE0000924 and DE-OE0000925.

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Executive Summary

The current and anticipated growth of distributed energy resources (DERs) is changing the energy landscape. Unmanaged, DERs have the potential to disrupt grid operations and require additional infrastructure build out. However, when managed and incentivized appropriately, DERs—especially when aggregated—can provide tremendous value to the grid and reduce unnecessary system costs.

State-level policymakers and regulators have the opportunity to establish rules and requirements for aggregated DERs (ADERs) and enable policies and programs to bring these resources online safely and effectively. However, as ADERs continue to evolve, there are a myriad of technical and economic challenges policymakers will have to overcome. Establishing the successful and sustainable use of ADERs to support the grid will likely require iterative approaches as the industry changes, state priorities evolve, national standards are set, and new tools emerge.

This report is part of the National Association of Regulatory Utility Commissioners (NARUC)-National Association of State Energy Officials (NASEO) *DER Integration and Compensation Initiative*.[1] It is designed to be an accessible guide for understanding the fundamentals of ADERs so policymakers can make informed decisions that fit their state context and needs.

This report builds upon existing literature and leading examples of ADER pricing and programs in practice to equip commissioners and staff at Public Utilities Commissions (PUCs) and State Energy Offices with the fundamentals of ADER grid services, valuation options, and approaches to compensation. Examples, active debates, and opportunities for further reading are highlighted throughout the document for readers to explore. This report does not seek to outline a specific objective for ADERs in the electricity system nor does it recommend any specific policies for ADERs—it seeks to provide helpful information to inform policymakers' own ADER strategies and priorities.

Navigating This Report

This report consists of six key sections:

1. **Introduction—ADERs and Policymaking:** The introduction describes the evolution of DERs in the energy system and why DERs are becoming increasingly important in policymaking.
2. **How ADERs Provide Grid Services:** This section provides background context on how ADERs provide different services to the grid.
3. **ADER Grid Services:** The grid services section establishes a baseline understanding of the grid services ADERs can feasibly provide and which of these services ADERs are currently providing in the United States today. It covers grid services at the bulk power system, distribution, and "grid edge" (or customer) levels.
4. **ADER Valuation:** The valuation section explores different approaches to valuing grid services for customers, utilities, and grid operators. The valuation section also covers how to quantify non-energy benefits provided by ADERs, such as reducing greenhouse gas (GHG) emissions.
5. **ADER Compensation:** The compensation section provides an overview of the various approaches to compensating ADER managers and ADER participants, including both customers and program implementers, such as utilities or aggregators. The section covers two key compensation approaches: prices and programs.

1 NARUC, "NARUC-NASEO Distributed Energy Resource Integration and Compensation," https://www.naruc.org/core-sectors/energy-resources-and-the-environment/energy-distribution/der-integration-compensation/.

6. **Case Studies:** The report concludes with three case studies, which detail ADER policies and programs implemented in three different state and market contexts. The case studies highlight each case's enabling context, program details, and lessons learned.

The core of the report—the Grid Services, Valuation, and Compensation sections—all include a short overview of the topic followed by a section that captures fundamental questions policymakers are asking as they design programs and policies to utilize ADERs.

Throughout, text boxes highlight specific information for readers: "Focus area" (blue boxes) provide further information beyond the main body of text, and "Industry developments explainer" (green boxes) provide insight into new industry developments not yet incorporated into current practices.

Terms

In this report, we use the following definitions:[2, 3, 4, 5, 6]

Distributed energy resources (DERs) are devices or technologies that interface with the electricity system (i.e., consume, store, or inject power) at the distribution level, either by directly connecting to the distribution utility's wires or on an end-use customer's system.[7, 8] DERs include distribution-connected renewable resources, energy efficiency, energy storage, electric vehicles, and demand response.

Aggregated distributed energy resources (ADERs) are groups of DERs capable of providing one or more services to the electric grid through dispatch or control. ADERs can be managed and orchestrated by software that controls their operations. Where hardware is incapable of receiving software signals or where the customer prefers direct control, manual operation can also be used to control individual DER operations as part of a DER aggregation. ADERs can consist solely of one technology (e.g., thermostats) or multiple technologies (e.g., batteries, solar photovoltaic (PV) systems, smart water heaters, etc.). The term is used in this report interchangeably with virtual power plants (VPPs).

In this report, ADERs only include DERs that can be dispatched or controlled. This definition does not include energy efficiency, which cannot be controlled to provide grid services. This report uses the DER taxonomy presented by the U.S. Department of Energy (DOE) in *Pathways to Commercial Liftoff for Virtual Power Plants* when describing the grid services that ADERs can provide.[9] These are: demand DERs, generation DERs, and storage DERs.

	Examples of Technologies that Can Be Aggregated into ADERs or VPPs
Demand DERs	Electric vehicle (EV) chargers, smart thermostats paired with electric building technologies such as heat pumps, electric water heaters, and commercial and industrial (C&I) equipment
Generation DERs	Distributed solar, fuel-based generators
Storage DERs	Behind-the-meter (BTM) battery storage systems (whether connected to distributed generation or not) and EV batteries

2 These definitions are derived from the following resources: Jingjing Liu et al., *State of Common Grid Services Definitions*, Lawrence Berkeley National Laboratory (LBL), 2022, https://eta-publications.lbl.gov/sites/default/files/gmlc_state_of_grid_services_report.12.12.22.pdf.

3 North American Electric Reliability Corporation (NERC), *Essential Reliability Services Task Force: A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability*, 2014, https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Concept%20Paper.pdf.

4 Electric Power Resource Institute, *Grid Services in the Distribution and Bulk Power Systems: A Guideline for Contemporary and Evolving Service Opportunities for Distributed Energy Resources*, 2021, https://www.epri.com/research/products/000000003002022405.

5 NERC Inverter-Based Resource Performance Task Force (IRPTF), *Fast Frequency Response Concepts and Bulk Power System Reliability Needs White Paper*, March 2020, https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf.

6 U.S. Department of Energy (DOE), Office of Electricity, *Bulk Power, Distribution, and Grid Edge Services Definitions*, 2023, https://www.energy.gov/sites/default/files/2023-11/2023-11-01%20Grid%20Services%20Definitions%20nov%202023_optimized_0.pdf.

7 Docket No. 22-OII-01 in Order No. 22-0309-8, "In the Matter Of: Distributed Energy Resources in California's Energy Future," California Energy Commission (CEC), March 9, 2022, https://www.energy.ca.gov/filebrowser/download/4010; in their 2016 paper, Distributed Energy Resources Rate Design and Compensation, p. 41, https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

8 Staff Subcommittee on Rate Design, *NARUC Manual on Distributed Energy Resources Rate Design and Compensation*, NARUC, 2016, https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

9 Jennifer Downing et al., *Pathways to Commercial Liftoff: Virtual Power Plants*, 2023, http://liftoff.energy.gov/wp-content/uploads/2023/10/LIFTOFF_DOE_VVP_10062023_v4.pdf.

Grid edge is used to describe electric grid locations that are beyond either distribution grid metered connections or microgrid islanding points. This means that the electricity beyond these points can be managed independently of the wider electric grid to support customers' requirements.

Grid requirements are the physics-based needs of the electric grid to maintain safe and reliable electric service.

Grid services are a set of parameters that describe changes to active and/or reactive power characteristics that grid operators and/or utilities can procure or request from generation, demand, and storage resources. They include, for example, frequency control, capacity, and reserves.

ADER grid services are specific, distinguishable benefits that an intentional use of many individual DERs can provide to maintain a reliable and stable electric grid.

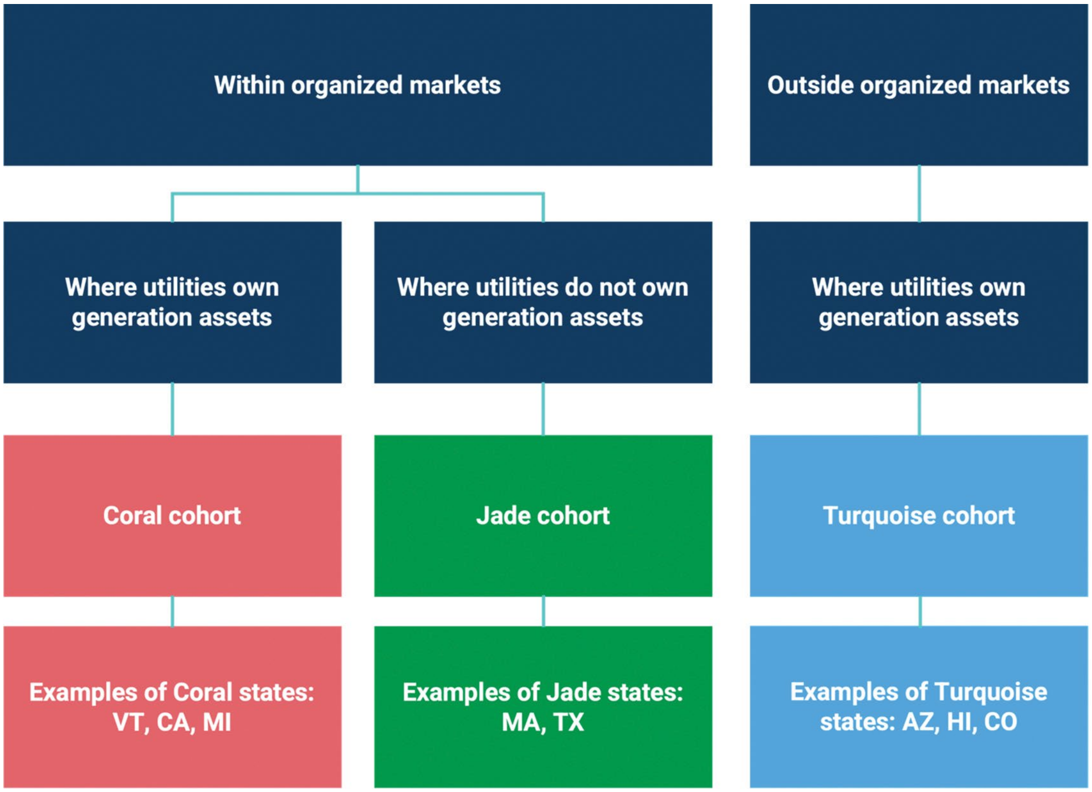
Grid edge services are the specific active and reactive power changes that support customers or microgrids beyond metered connections or islanding points to maintain reliable electric service.

Policymakers refers to commissioners, directors, and staff at PUCs and State Energy Offices.

Prices and programs are means of sending signals to customers to modulate their active and/or reactive power to provide a grid service.

Finally, as elements of ADER grid services, valuation, and compensation may look different across regulated and deregulated contexts, this report leverages the cohort model introduced in the NARUC-NASEO *Task Force on Comprehensive Electricity Planning*.[10] The different cohorts are summarized in **Figure 1**.

Figure 1: Overview of State Cohorts



10 NARUC, "Task Force on Comprehensive Electricity Planning," https://www.naruc.org/committees/task-forces-working-groups/retired-task-forces/task-force-on-comprehensive-electricity-planning/home/.

Introduction

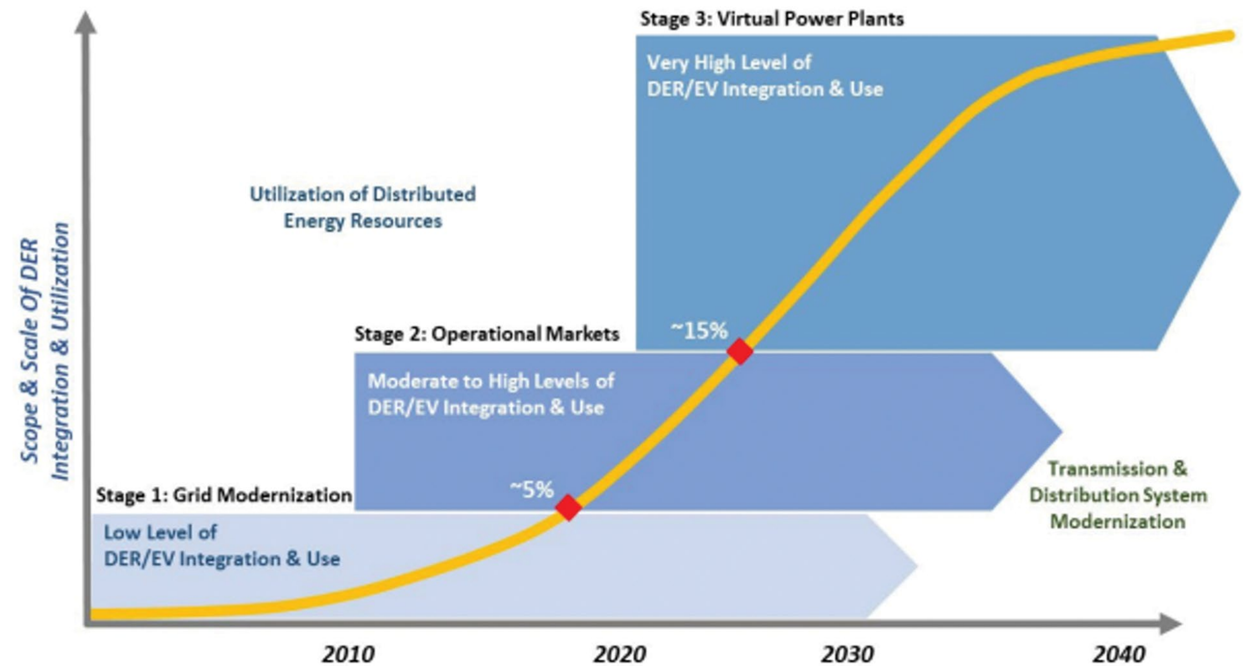
The Evolution of DERs in the Energy System and the Role of Energy Policy

DERs are coming online at increasing rates, with the total U.S. market for DERs expected to double between 2023 and 2027.[11] The impact that these resources will have on the electricity system will be determined, in part, by the decisions of state policymakers.

Individual DERs have been providing grid services for nearly three decades. Early DER programs mostly took the form of net energy metering (NEM), where utility customers installed DERs and received the retail rate for the electricity they exported to the grid.[12] Several notable trends over recent years, including increasing levels of renewable penetration and end use electrification, are expanding the focus of DER policies to include how to best utilize aggregations of DERs, or ADERs, to deliver a range of benefits to the electric grid.

The 2023 DOE paper, *Distribution System Evolution*, offers a compelling structure for understanding changes in how DERs interact with the electric grid, charting the stages of evolution.[13]

Figure 2: Distribution System Evolution



As illustrated in **Figure 2**, in the initial stage titled "Grid Modernization," DER penetrations are low and can be accommodated in existing distribution systems with minimal material changes to planning, infrastructure, and operations. Grid modernization investments are required to improve reliability and resilience and accommodate expected DER adoption. In the next stage, "Operational Markets," DER penetrations reach 5–15% of distribution system peak, and DERs are increasingly used for load modification and generation across non-wires solutions (NWS) and wholesale capacity and ancillary services. In the final stage, "Virtual Power Plants," DER penetrations exceed 15% of peak load, and ADERs are orchestrated to manage a suite of grid services on both distribution and transmission systems.

11 Sonia Kerr et al., "U.S. Distributed Energy Resource market to almost double by 2027," Wood Mackenzie, June 20, 2023, https://www.woodmac.com/press-releases/us-distributed-energy-resource-market-to-almost-double-by-2027/.

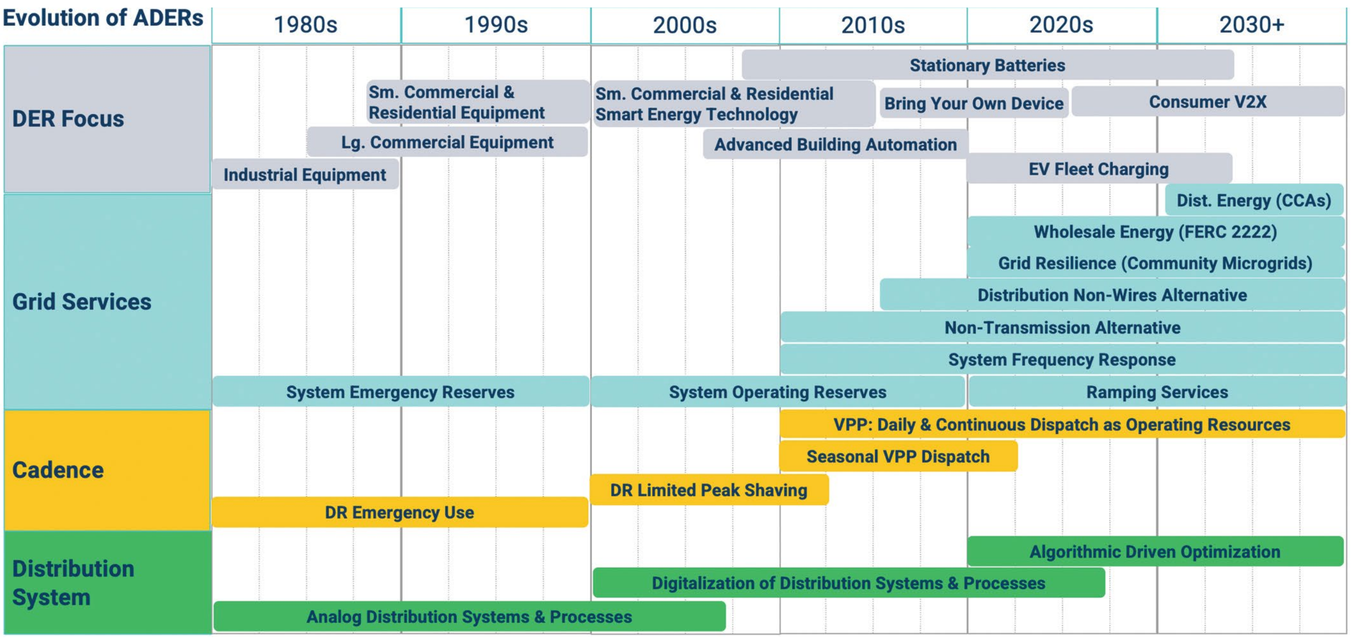
12 Ashley J. Lawson, *Net Metering: In Brief,* Congressional Research Service, 2019, https://crsreports.congress.gov/product/pdf/R/R46010.

13 U.S. DOE, Office of Electricity, *Distribution System Evolution*, 2023, https://www.energy.gov/sites/default/files/2023-11/2023-11-01%20Distributed%20System%20Evolution%20nov%202023%20r1_optimized.pdf.

Importantly, states are currently exploring whether they can achieve this final stage of distribution system evolution within existing constructs or whether there is a need for a more significant change to roles and operational approach, such as the introduction of a distribution system operator.

Figure 3 provides a more granular view of the evolution of the distribution system and the grid services DERs can provide. This graphic shows how the industry has moved from the traditional use of individual DERs for limited set of emergency grid needs to a future with continuous ADER optimization for a wide range of grid services on transmission and distribution systems.

Figure 3: Evolution of ADERs



While there are multiple factors that impact this evolution and what becomes possible in the next few decades, there are a number of trends underway across the United States that are moving the industry toward this vision.

Customers are installing DERs at increasing rates: NEM tariffs and other technology-specific incentives have encouraged DER adoption at a growing rate over the last few decades. With a range of new federal incentives for DERs now available, adoption rates are expected to increase significantly over the next 5 to 10 years.[14, 15] While customers usually purchase DER technologies as consumer goods, not as grid-enabled energy resources—for example, EVs are bought for transport and heat pumps for comfort at home—there are emerging opportunities to shorten customer payback timelines by compensating them for the range of grid services their technologies can provide.

The grid services DERs provide are expanding: DERs have historically been compensated for direct export of power and for demand response for resource adequacy, including emergency and operating reserves. Grid operators and utilities are increasingly considering how to utilize a suite of grid services from DERs to manage safe and reliable electric grid operation. Federal Energy Regulatory Commission (FERC) Order 2222, which requires wholesale market operators to develop policies that enable aggregations of DERs to participate in

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14 The Inflation Reduction Act sets a series of incentives and benefits for DER uptake; Scott Minos, "Energy Saver: Inflation Reduction Act of 2022—What It Means for You," U.S. DOE, https://www.energy.gov/energysaver/articles/inflation-reduction-act-2022-what-it-means-you.

15 The International Council on Clean Transportation (ICCT) project that by 2032, the final year of Inflation Reduction Act Funding, EV sales shares will reach 56–67%; Peter Slowik et al., *Analyzing the Impact of the Inflation Reduction Act on Electric Vehicle Uptake in the United States,* International Council on Clean Transportation, 2023, https://theicct.org/publication/ira-impact-evs-us-jan23/.

organized electricity markets and to establish participation models that fit the unique technical and operating characteristics of DERs, will accelerate these efforts.[16, 17]

The cadence of DER dispatch is increasing: DERs have gone from being used for periodic peak management to increasingly being used to manage regularly occurring grid services. This change is in part driven by policymakers' desire to see DERs support policy goals, including reducing GHG emissions, improving customer affordability, supporting social equity, and improving the resilience and reliability of the electric service. Aggregating and orchestrating DERs is essential to manage an increasing cadence of dispatch.

The distribution system itself is evolving: The electric grid is going from analog, centralized systems to a complex, digitalized network of energy flows.[18] New technologies are enabling better visibility, coordination, and utilization of DERs to provide grid services.[19] Designing policies that support ADER grid services can support utilities in planning a cost-efficient and reliable distribution system.

Setting a Direction for ADER Policies

Successful ADER policies are tailored to meet specific public policy goals driven by state priorities and contexts. Setting a direction for what a state wants ADERs to provide is key in defining the right set of policies and programs. There are many ways to approach policy direction setting, and states should leverage previous experiences and lessons learned by relatable states to inform policy development. In places where ADER policies have been successfully implemented, policy direction setting has broadly included the following steps:

1. **Define the problem statement:** Determine what issues need to be addressed. For example, these could include any of the following: reduce GHG emissions, reduce costs, improve customer affordability, support social equity, improve resilience, defer or avoid infrastructure investment, increase efficiency of the distribution system, support service reliability, or empower customers.
2. **Assess available information:** Gather information on the current status of ADERs in the state and review information from other states (e.g., case studies in the appendix of this document) that have implemented ADER policies.
3. **Understand policy feasibility:** Identify the enablers and challenges to changing a jurisdiction's level of ADER support. Determining the feasibility of change will help set a realistic and tangible policy direction.
4. **Set a policy direction:** Articulate what the desired future end state is and how ADERs can support meeting priority policy outcomes. Setting a policy direction for the role of ADERs will help ground policymakers in the process of developing their ADER plans. It also can be helpful to develop a set of ADER principles that support alignment across stakeholders and that document governing basic parameters, methods, and goals.[20]
5. **Prioritize key enablers to deliver policy outcomes:** Determine the highest value actions to start delivering policy outcomes.

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16 Federal Energy Regulatory Commission, "FERC Order No. 2222 Explainer: Facilitating Participation in Electricity Markets by Distributed Energy Resources," last updated June 14, 2023, https://www.ferc.gov/ferc-order-no-2222-explainer-facilitating-participation-electricity-markets-distributed-energy.

17 Brittany Blair et al., *Encyclopedia of DERMS Functionalities*, Smart Electric Power Alliance, 2023, https://sepapower.org/resource/encyclopedia-of-derms-functionalities/.

18 NARUC's paper provides a grounding in the changes taking place to electric grids in the United States; Lynne Kiesling, *Digitalization in Electric Power Systems and Regulation: A Primer, NARUC, 2022,* pubs.naruc.org/pub/17AB6931-1866-DAAC-99FB-8D696CC1944A.

19 National Renewable Energy Laboratory (NREL), "Distributed Energy Resource Management Systems," https://www.nrel.gov/grid/distributed-energy-resource-management-systems.html.

20 RMI's Virtual Power Plant Partnership (VP3), representing 25 VPP technology and service providers, developed a set of policy principles to enable VPPs; Avery McEvoy et al., *VPP Policy Principles, RMI, 2024,* https://rmi.org/insight/vpp-policy-principles/.

Figure 4: Policy Setting for ADER Policies

How Priority Policy Outcomes Impact ADER Policy Development

States may wish to focus on one or several priority policy outcomes when considering ADER policy development. **Table 1** provides a set of potential priority policy outcomes and associated considerations.

Table 1: Priority Policy Outcomes and Considerations for ADER Policy Development

Priority policy outcome	Considerations for ADER policy development
GHG reductions	The value of GHG reductions may need to be explicitly factored into benefit-cost analyses (BCAs) or utility resource planning processes, such as using the social cost of carbon (SCC).[21] Consideration should be given to accurate accounting and whether to include or exclude monetized costs of other GHGs in BCAs or plans. GHG lifecycle analysis may be a useful tool to consider the entire range of economic and societal costs of traditional generation and DERs.
Pollutant emission reductions	The reduction in emissions from non-GHG pollutants also provides environmental and health benefits. These benefits have been quantified by the U.S. Environmental Protection Agency (EPA) and are publicly available.[22] Policymakers should consider whether to include or exclude other emissions benefits in BCAs or plans.
Ratepayer affordability	Utilizing ADERs can lower system costs by avoiding or deferring the need to build new power plants (ADERs serving as VPPs) or to invest in transmission and distribution infrastructure (ADERs serving as NWS). Comprehensive BCAs can be used to establish adequate, yet fair, compensation for ADER managers and participants and ensure cost-effective ADER programs. Further discussion on this can be found in the section titled "ADER Valuation." Policymakers may need to consider current vs. future benefits and costs of enabling ADER grid services and whether there is value in priming markets by over-paying for ADER grid services.
Social equity	The impact of different compensation mechanisms on various customer groups' ability to provide ADER grid services and the associated equity outcomes.
Resilience	How ADER policies can enable microgrid and/or islanding support, as well as grid edge services.

21 The concept of a social cost of carbon (SCC) is designed to include economic, social, and environmental impacts of carbon. Estimates for SCC vary significantly and are discussed in greater detail in the ADER Valuation section. Elijah Asdourian and David Wessel, "What Is the Social Cost of Carbon?," *Brookings,* March 14, 2023, https://www.brookings.edu/articles/what-is-the-social-cost-of-carbon/.

22 U.S. Environmental Protection Agency (EPA), "Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA)," last updated April 24, 2024, https://www.epa.gov/cobra.

Priority policy outcome	Considerations for ADER policy development
Reliability	The purpose of all grid services is to maintain a reliable grid. Grid services provided by ADERs may be more affordable or have other benefits than traditional reliability resources. Policymakers may consider the comparative reliability services of ADERs and traditional generation resources.[23]
Customer empowerment	Consideration may be given to the ability of DER owners to control and monetize value streams from their DERs, and the data required to enable them to do so.

Focus area: Social Equity: Ensuring ADERs Enable More Equitable Outcomes

The challenge

In today's energy system, BIPOC communities are often disproportionately affected by poor air quality resulting from nearby polluting energy infrastructure.[24, 25] Recent efforts to deploy residential solar have demonstrated that without consideration of racial equity, BIPOC communities were excluded from the benefits.[26] At the same time, low-income households spend a disproportionate percentage of their income on energy—up to three times as much as non-low income homes.[27]

ADERs have the potential to advance a more just energy transition

Unlocking the potential for ADERs to provide grid services can reduce some of these social inequities. Using ADERs instead of gas peaker plants to provide capacity, for example, reduces emissions of harmful air pollutants into nearby communities, which disproportionately affect low-income and BIPOC communities today.[28] DER adoption also provides direct benefits to participants, such as reducing costs and improving resilience. Policies that encourage DER adoption in low-income and BIPOC communities and development of ADER programs ensure these communities are able to receive the benefits that ADERs offer participants.

Policy considerations to better support social equity

Policymakers often have a role in ensuring that ADER policies support social equity. For some states, ensuring that ADER policy and programs are equitable is required. Over 40% of states have codified requirements that PUCs must consider equity either broadly or support equity in specific programs.[29]

Three notable considerations for policymakers include:

- **Are there existing infrastructure barriers preventing some communities from accessing DERs?** Policymakers can proactively identify and potentially address infrastructure barriers that many BIPOC communities face (e.g., underinvestment in distribution networks) to ensure all communities can access ADER benefits.

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23 Reliability is considered in further detail in "Part 1 – ADER Grid Services," including the certainty that ADERs can delivery required grid services, and the comparative reliability of traditional generation.

24 BIPOC refers to black, indigenous, and other people of color.

25 "Disparities in the Impact of Air Pollution," *Lung.org*, last updated November 2, 2023, https://www.lung.org/clean-air/outdoors/who-is-at-risk/disparities.

26 Kalimah Redd Knight, "Study: Racial Inequality in the Deployment of Rooftop Solar Energy in the U.S.," *Tufts,* January 10, 2019, https://now.tufts.edu/2019/01/10/study-racial-inequality-deployment-rooftop-solar-energy-us.

27 U.S. DOE, Office of State and Community Energy Programs, "Low-Income Energy Affordability Data (LEAD) Tool and Community Energy Solutions," https://www.energy.gov/scep/slsc/low-income-energy-affordability-data-lead-tool.

28 Seth Mullendore, "Peaker Power Plant Data Show Persistent Economic and Racial Inequities," *Clean Energy Group*, September 7, 2023, https://www.cleanegroup.org/peaker-power-plant-data-show-persistent-economic-and-racial-inequities/.

29 Marguerite Behringer, "Equity at the Public Utility Commissions: Recent Research and Lessons," *Clean Energy Action*, February 22, 2022, https://www.cleanenergyaction.org/blog/equity-research-2021.

- **How do ADER programs and policies enable low-income families to access the benefits of DERs and ADERs?** Policymakers can ensure that ADER programs are designed such that all communities can participate in markets through aggregators or in utility programs. DER owners who are compensated for ADER grid services will see shorter payback periods for their DER investments through upfront incentives and performance payments and, in some cases, savings on energy bills.
- **How can ADERs improve resilience for communities?** ADERs can provide resilience benefits to individuals and communities. Policymakers can ensure that communities with the highest risk of outages due to natural disasters and aging energy infrastructure (e.g., remote, island, and tribal communities) have access to ADERs that improve resilience.

Key Stakeholders in ADER Policy Development

ADERs are innately a cross-cutting topic, requiring coordination and cooperation across numerous organizations. As with many complex topics, policymakers will need to balance views from a diverse set of stakeholders. **Table 2** summarizes the key stakeholders in ADER policy development.

Table 2: Key Stakeholders in ADER Policy Development

Stakeholders	Role	Interests
Advocates (environmental groups, energy justice organizations, etc.)	Advocate policy/decision making in the interest of policy objectives, including broader societal benefits such as environmental protection or social equity	Reduced GHG emissions; customer affordability; reliable and resilient electric service; customer equity; customer empowerment; and expansion of markets for low-carbon technologies
DER customers	Own or manage DERs and participate in ADER grid services	Customer and community health and safety; lower bills; reliable electric service; DER equipment longevity; customer comfort; ease of participation; and payback on investment
Consumer advocates	Represent ratepayer interests	Customer affordability; reliable and resilient electric service; customer equity; and avoided ratepayer infrastructure investment
Independent System Operators (ISOs)/Regional Transmission Organizations (RTOs)	Organize wholesale markets for grid services	Reliable ADER grid services
Public Utilities Commissions (PUCs)	Set and enforce utility regulations	Regulatory governance that aligns with providing customers safe, reliable, and affordable electricity service and, where applicable, advances state policy objectives; increased system efficiency; accommodation of increased load; and avoidance or deferral of ratepayer investment in infrastructure

Stakeholders	Role	Interests
Retailers	In restructured markets, retailers may be responsible for implementing ADER programs.[30]	ADER program design; customer acquisition; and reliable ADER grid services
State Energy Offices and state legislators	Design and implement state energy policies in support of public policy objectives	Policies that minimize risks for constituents, stimulate the local economy, and meet state goals and policy objectives
Utilities	Provide safe and reliable power to customers at reasonable rates	Reliable ADER grid services and business impact of ADERs, including shareholder returns
DER providers/installers/ manufacturers	Provide DER equipment that can then be aggregated to provide grid services (inclusive of all DER technologies)	Increased DER adoption and reduced regulatory hurdles to interconnection
VPP technology or service providers/aggregators (including utilities in some jurisdictions)	Provide the technology that enables the aggregation of DERs to provide grid services and aggregate the DERs, if appropriate Various business models exist among these firms.[31]	Usually for-profit entities seeking to efficiently and economically provide ADER grid services, benefit their customers, and benefit shareholders

The role of aggregators will be especially important to consider in ADER policy development. Aggregators are responsible for the coordination of DERs under their portfolio to meet grid service requirements. While this can be the utility, separate for-profit or non-profit third-party organizations also can manage ADERs that deliver grid services to both distribution and bulk power systems.[32] Moreover, utilities and third parties can form partnerships to deliver ADER programs. Aggregators can provide services such as customer enrollment and support, device management and dispatch, a single point of settlement for the utility or program administrator, de-risking underperformance by relying on services provided by a fleet of DERs, and/or program administration. Aggregators also can assume risks on behalf of their customers to shield them from price volatility and help share information and analyses to enhance DER forecasting capabilities.

There have historically been few nationwide standards for the role of aggregators, leaving individual utilities, states, and Regional Transmission Organizations (RTOs)/ Independent System Operators (ISOs), where applicable, to define their own rules and standards for contracting, agreements, coordination with the distribution utility, and other key elements. The DOE "Operational Coordination" group has initiated work defining standardized guidance, codes, and contracts, providing helpful common approaches. For example,

30 We use the term "utilities" to refer to both distribution utilities and other suppliers/retailers in the paper.

31 The role that aggregators and technology service providers can play varies widely. There are traditional DER aggregators that aggregate DERs without providing their own technology for controlling them. There are technology service providers that provide program implementers with software for aggregating and controlling ADERs. There are also entities that can do both and are able to implement ADER grid services end-to-end. There are also entities that collect and standardize data and price and grid signals that help implementers aggregate DERs and control them.

32 We use the term aggregators to represent a wide range of companies aggregating DERs, including VPP companies, microgrid developers, and automated service providers (who can provide services such as price responsive automation).

efforts to provide contract standardization to ensure interoperability across regions are ongoing.[33] For RTO/ISO regions, FERC Order 2222 requires that the aggregator be responsible for "managing, dispatching, metering, and settling" for individual DERs, but allows each RTO/ISO to provide further role definition.[34, 35]

Notably, FERC Order 2222 includes a "Coordination Framework," which FERC launched as a prospective means for coordination between wholesale market operators and utilities, aggregators, and state utility regulators. FERC recommended development of regional coordination frameworks to address coordination issues that arose not only from their Order 2222 decision, but many other related issues that will likely need to be taken up in the future.[36] Priorities will need to be established to protect distribution system level issues in the event of natural disasters, other major events, or reliability issues.

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33 The DOE 2023 paper, "Standard Distribution Services Contract," outlines work with the North American Energy Standards Board (NAESB) to develop standardized contracts for DER aggregation participation in grid services; U.S. DOE, Office of Electricity, *Standard Distribution Services Contract*, 2023, https://www.energy.gov/sites/default/files/2023-11/2023-11-15%20Standard%20Distribution%20Services%20Contract_optimized.pdf.

34 Federal Energy Regulatory Commission, Docket No. RMI18-9-000, "Order No. 2222: Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators," September 17, 2020, p. 184, https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf.

35 NARUC-NASEO DER Integration and Compensation Initiative, "Overview of RTO/ISO Filing Status in Response to FERC Order 2222," last updated November 2023, https://pubs.naruc.org/pub/0C205FC7-C2D1-071A-B5F3-70BF27231837.

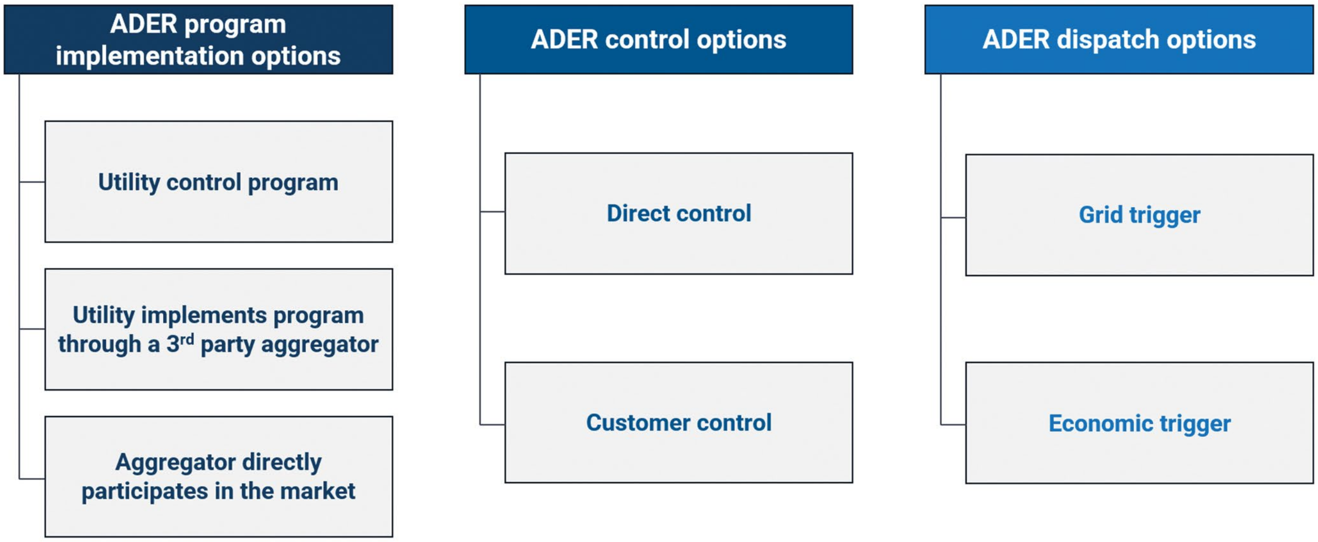
36 Electric Power Research Institute, *Coordination Frameworks to Meet the Needs of FERC Order 2222: An EPRI FO2222 Phase 1 Collaborative Effort*, 2021, https://www.epri.com/research/products/000000003002020593.

How ADERs Provide Grid Services

ADERs provide grid services by receiving grid service signals and responding by adjusting customer demand, storage, and/or generation. The mechanisms for controlling ADERs vary by grid service type and ADER technical capabilities. ADER control can be carried out by different parties dependent on the state context and grid service design.

Figure 5 summarizes the range of options for how ADERs provide grid services.

Figure 5: Mechanisms by Which ADERs Provide Grid Services[37]



Foundational Questions

How are ADER programs structured?

Between market operators, utilities, and third-party aggregators, there are several options for how grid services from ADERs can be dispatched to meet a grid need. As ADERs continue to evolve, there may be additional options to utilize ADERs. Today, there are three main options:

1. **The utility implements an ADER program:** If a utility implements an ADER program directly, it will aggregate customer DERs, determine participation terms, and dispatch the resources.[38] The utility will determine how the ADER is controlled, the incentive structure and amount, and incentive payment cadence.

2. **The utility implements an ADER program through a third-party aggregator or contracts with an aggregator for grid services:** If an aggregator is implementing an ADER program for the utility as a program administrator, it will coordinate customer DERs, determine the participation terms, and distribute incentives to participants. The utility will notify the program administrator when the utility needs to dispatch the resources or will pre-determine the grid conditions that trigger an ADER dispatch. The utility and the aggregator will agree upon what service is provided (e.g., five MW of load shed) and how the aggregator

37 Grid services can be provided at the bulk power system level or at the distribution level. The dispatch options can similarly be triggered either by system needs or distribution needs. Please see the *Grid Services section for more information on how bulk power system and distribution grid services differ.*

38 Participation terms typically take the form of a customer agreement. If, for example, a customer's battery is being controlled by the utility in exchange for an incentive, the customer will typically sign an agreement with the utility that dictates when the utility can control the battery system and how much the participant will be compensated in exchange for this service. The different forms of incentives and compensation structures are discussed in greater detail in the "ADER Compensation" section.

will be compensated. The aggregator manages how participant load is controlled, the incentive structure, and the incentive amount. Alternatively, utilities can contract with aggregators to deliver specific grid services. Contracts typically specify discrete grid services needed and performance expectations, including requirements for asset visibility, operational coordination, compensation, evaluation, and customer engagement.[39]

3. **An aggregator directly participates in the wholesale market to provide grid services:** Direct wholesale market participation is only available where there are organized markets (i.e., Jade and Coral cohorts). There also needs to be an existing rule in place allowing ADERs to participate directly in the wholesale market. Similar to the role of the aggregator when working with a utility, the aggregator will coordinate customer DERs, determine the participation terms, and design the incentive structure. However, instead of a pre-determined incentive for the aggregator, the aggregator's revenue is determined by how often the resources are dispatched in the wholesale market and the clearing price at which they are dispatched. The aggregator determines how to compensate its participants. Aggregators can participate in wholesale capacity, energy, or ancillary service markets depending on the availability of grid services required and on the availability of ADERs able to provide the grid services. While historically aggregators have been limited to wholesale market participation, a few states are exploring different market configurations to provide distribution-level grid services as well.

Industry developments explainer: Distribution Markets

Some states are considering and piloting distribution markets. These markets provide a means for utilities to secure ADER distribution system grid services through a competitive process, rather than through requests for proposals (RFPs) in their own programs, or retail rates. These distribution markets are independent of ISO/RTO markets and can therefore be considered by any state.

Distribution markets often function with an intermediary "market platform" organization responsible for matching bids and offers between the utility and aggregators.[40] However, such a role is not strictly required and could be undertaken by the utility.

Distribution markets are closely associated with the concept of a Distribution System Operator, where a distribution entity takes an increasingly active role in managing grid services within the distribution grid. California and Maine have considered or are considering the role of a Distribution System Operator.[41, 42]

Distribution markets are also being developed in Europe.[43]

39 *Standard Distribution Services Contract*, 2023.

40 For example, market platform operator Piclo is expected to undertake trials with United Illuminating in Connecticut as part of the Public Utilities Regulatory Authority (PURA) Innovative Energy Solutions (IES) program; "Piclo and United Illuminating to Develop First DER-Enabled Grid Flexibility Market in Connecticut," Piclo, February 22, 2024, https://www.piclo.energy/press-releases/piclo-and-united-illuminating-to-develop-first-der-enabled-grid-flexibility-market-in-connecticut.

41 "California Future Grid Study," Gridworks, last accessed April 26, 2024, https://gridworks.org/initiatives/california-future-grid-study/.

42 "Distribution System Operator Feasibility Study," *Maine.gov,* last accessed April 26, 2024, https://www.maine.gov/energy/studies-reports-working-groups/current-studies-working-groups/distribution-system-operator-study.

43 Council of European Energy Regulators, *CEER Paper on DSO Procedures of Procurement of Flexibility,* 2020, https://www.ceer.eu/documents/104400/-/-/f65ef568-dd7b-4f8c-d182-b04fc1656e58.

Table 3 below summarizes the frequently cited critiques of each ADER utilization structure.

Table 3: Frequently Cited Critiques of ADER Utilization Structures

	Proponents' Comments	Opponents' Comments and Considerations
Utility implements program directly	• Utilities are able to directly utilize ADERs without the costs of intermediary aggregators. • Utilities have pre-existing customer relationships and data. • Investor-owned utilities have regulatory oversight.	• If new to ADERs, utility program implementation could be complicated and more costly compared to other entities. • There is no competitive pressure to improve ADER program implementation. • Utility planning and implementation timelines may be longer than those of third parties or markets. • Pay for performance tariffs implemented by a utility may require a proceeding, which can take longer than if compensation is implemented through a third party.
Third party implements program on behalf of utility as a program administrator	• Third parties work in tandem with utilities when implementing program, which by extension includes regulatory oversight. • Third parties enroll customers for the utility, reducing utility labor and efforts. • Third parties can reduce utility overhead costs.	• Implementation strategies can be limited to utility program rules. • There are additional costs from third-party fees.
Third party contracts with a utility to provide grid services through a procurement process	• Third parties can innovate and compete with one another to lower costs and improve program outcomes. • Third parties may have flexibility on what resources they can acquire to provide grid services. • Third parties can reduce utility overhead costs.	• Utilities often need to share data with third parties, which may create additional technical barriers or cybersecurity concerns. • Third parties are likely subject to limited or no regulatory oversight.
Aggregator directly participates in wholesale market	• The value of grid services reflects actual wholesale market conditions. • Removes additional costs of intermediary programs. • Competition in wholesale markets creates a downward pressure on prices as aggregators compete to provide grid services at the lowest possible cost.	• Potential for higher risk for market participants because revenue is less certain. • Availability payments may limit options to participate in other ADER grid services. • Can be complex to establish.

Who controls ADERs?

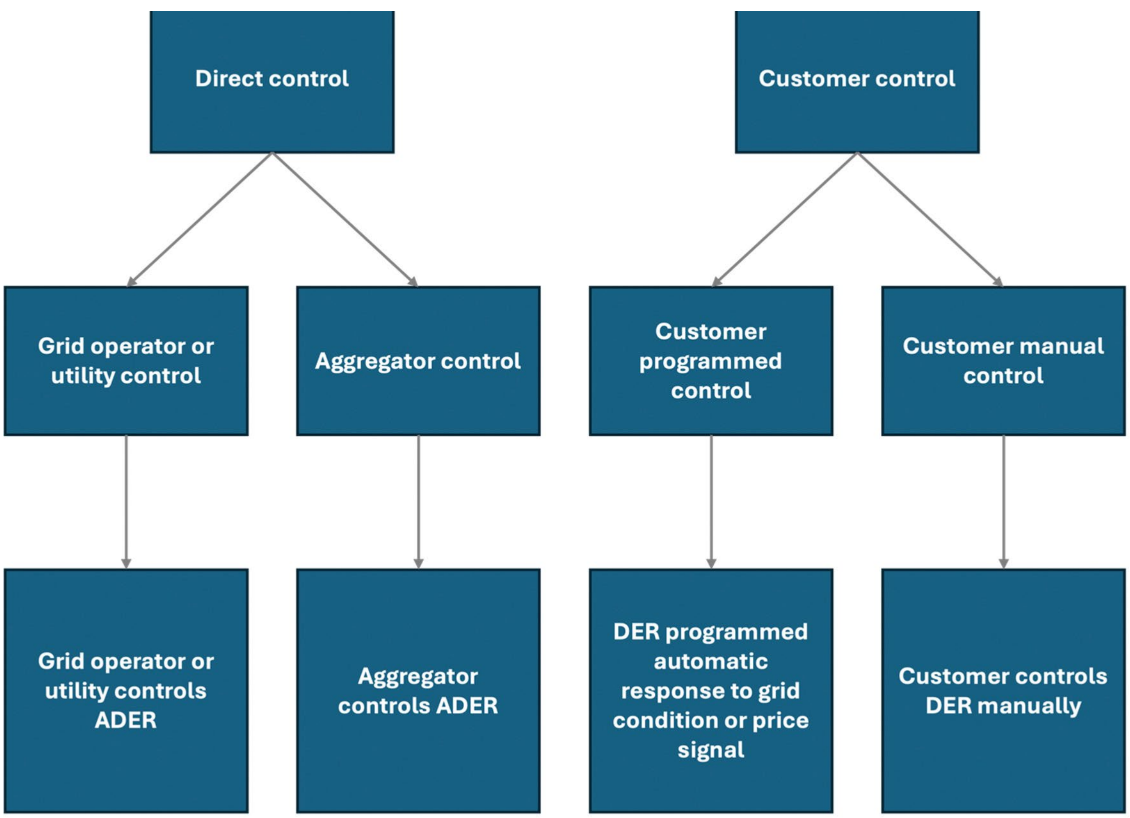
ADER control can include both behind-the-meter (BTM) generation and demand management. There are multiple paths for controlling ADERs once the ADER has been signaled for dispatch. Typically, ADER program implementers select the control method for ADERs.[44] There are generally two control options:

1. **Direct Control:** With direct control, the program implementer has the right to dispatch the ADER remotely. The implementer typically only controls the device under pre-specified conditions and typically notifies the participant when their device is being controlled. Participants are also often allowed to opt out of the event. Examples of direct control include customers allowing the utility access to their smart thermostats or battery storage systems in exchange for an incentive.

2. **Customer Control:** With customer control, the program implementer allows the ADER program participant to control their own DER during an event. This can also be done on an aggregate level—a fleet owner, for example, could be asked to use an entire ADER fleet (e.g., EVs) to provide a grid service and get paid based on how well the fleet of resources performs, in aggregate.45 Customers have two options for controlling their DER. The first option is for the customer to program their DER to automatically respond to a grid or price signal. In this option, the DER can detect changes in grid conditions or prices and respond to them automatically. Alternatively, the customer can manually control their DER in response to an external signal. In this instance, the customer will control the DER themselves once they have received a signal to do so.

The paths to modifying ADER load discussed above are summarized in **Figure 6**.

Figure 6: Routes to Controlling ADERs



44 As noted in the previous section, implementers can include the utility or a third party.

45 In California, for example, the Emergency Load Reduction Program (ELRP) allows direct enrollment or enrollment through an aggregator. The program compensates both direct enrollees and aggregators at a rate of $2/kWh of load reduced. "Aggregator/DRP FAQ," Olivine Inc., last accessed April 26, 2024, https://elrp.olivineinc.com/aggregator-drp-faq/.

Table 4 summarizes the frequently cited critiques of different ADER control options.

Table 4: Frequently Cited Critiques of Different ADER Control Options

	Proponents' Comments	Opponents' Comments and Considerations
Direct Control	• Simplest design • Clear target value set for grid service needed. • Mostly predictable ADER performance (though customers can override control)	• Less flexibility for customer in terms of which load(s) or ADER devices can participate, limited to what can be controlled by implementer
Customer Control (programmed response)	• Fastest response time • "Set it and forget it" option for customer	• More difficult to set up and limited to DER technologies with this capability. • Necessary to determine and test grid signal or price signal ahead of time
Customer Control (manual response)	• Customer has more control over ADER participation and how much DER capacity they provide in a given event. • Good fit for large C&I customers that have more unique end use loads and specific business requirements that need to be considered when deciding on responding to an ADER grid service request. • Can accommodate many different DER technologies	• May be too slow for some grid services, such as voltage control. • More uncertainty around ADER performance compared to direct control; monitoring and verification (M&V) needed to confirm performance. • Customer agreements can be complex. Customers often define their megawatt (MW)/megawatt-hour (MWh) commitment up front, which may need to be validated using test events or during dispatch.

How are ADERs dispatched?

For ADERs that require a dispatch signal to operate (i.e., most demand response DERs and storage DERs), the dispatch process depends on the grid requirement and what process triggers the resource to be dispatched. If ADERs are bid into a wholesale market for example, the resources are typically dispatched by the grid operator if it is more cost-effective to dispatch ADERs than it is to deploy other resources. If the ADERs are not bid into a wholesale market, they can be dispatched if there is grid stress or another grid signal that triggers the resources to be dispatched.

ADER dispatch signals vary based on whether the services are provided at the bulk power system level or at the distribution level. At the bulk power system level, there are two primary ways in which ADERs can be triggered for dispatch:

1. **Grid Trigger:** The grid trigger can be system load exceeding a certain value necessitating a grid service to ensure electric service reliability, such as the highest load value for the month or year. For example, Electric Reliability Council of Texas (ERCOT) dispatches its demand response resources during the 15-minute peak interval of each month.[46] California ISO has a system for identifying grid stress and dispatches demand response resources if it reaches a "Flex Alert" stage or greater.[47]

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46 ERCOT uses a "4CP" calculation for its demand response dispatch based on peak load for each month; "Changes to the 4 Coincident Peak (4CP) Program in Texas," *Electric Choice, last accessed April 26, 2024,* https://www.electricchoice.com/blog/4-coincident-peak-program/.

47 For more information on how California ISO identifies emergencies, see "Emergency Notifications," California ISO, *last updated August 2023,* https://www.caiso.com/Documents/Emergency-Notifications-Fact-Sheet.pdf.

For grid services that require instantaneous or near instantaneous responses, the grid operator will provide the signal, or the generator itself will detect requirements to provide the grid service.

2. **Economic Trigger:** The economic trigger will occur when a specific market price point is reached. The resource may be a participant in an organized market, and the RTO/ISO will then dispatch the resource when it finds the resource to be economically beneficial.[48] Dispatch may also occur based on a market price point, with DER compensation based on agreed customer terms.

At the distribution system level, the only trigger currently in use in the United States is the "grid trigger," as identified by the utility. The utility can monitor its distribution equipment and identify when the equipment is strained or if the equipment's emergency rating is being exceeded. However, some states are currently exploring distribution markets, where there could be economic triggers introduced.[49]

48 PJM uses economic dispatch for demand response; "Demand Response," PJM, last updated March 18, 2024, https://learn.pjm.com/-/media/about-pjm/newsroom/fact-sheets/demand-response-fact-sheet.ashx.

49 See the "Programs" section in this report for more information on distribution markets.

ADER Grid Services

This section describes the services that ADERs are capable of providing to the electric grid. ADER grid services are defined as the specific, distinguishable benefits that an intentional use of many individual DERs can provide to maintain a reliable and stable electric grid. This section covers energy services required by utilities, grid operators, and customers, but does not cover wider non-energy services and benefits—these are detailed under the section titled "ADER Valuation."

Overview of Grid Services

To maintain a stable electric grid, grid operators must continuously and perfectly balance energy generation and demand. Matching demand and generation allows the electric grid to maintain a stable frequency. If generation outstrips demand, frequency increases; likewise, if generators do not export sufficient energy or demand outstrips generation, frequency drops.

Historically, demand and generation patterns were relatively predictable, and grid operators had only a few tools at their disposal to balance the grid. These included resources that generate significant amounts of energy (e.g., large generators such as a natural gas plant) or provide large sources of demand reduction (e.g., C&I equipment).

Today, generation and demand patterns are changing due to an increase in overall demand from beneficial electrification of buildings and transportation, growing industry electrification, and an increase in variability due to an increasing penetration of variable renewables. ADER grid services can help alleviate these challenges.

Grid Services Taxonomy

The following section uses a simplified grid services taxonomy to describe the requirements of maintaining reliability of the electric grid and outlines how these grid services can be met by ADERs. The simplified taxonomy is informed by a range of sources; however, we acknowledge that there will be state- and regulation-specific nomenclature and that grid services will continue to evolve as markets and service delivery arrangements change.[50, 51, 52, 53, 54] The intention is not to provide an exhaustive list of grid services, but to highlight for readers the principal grid services found across all states and discuss how these can be met by ADERs. Readers interested in further exploring grid service definitions are encouraged to review the sources referenced.

The following grid services taxonomy in **Figure 7** draws principally from the DOE 2023 report, Bulk Power, Distribution and Grid Edge Service Definitions.[55]

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50 Liu, *State of Common Grid Services Definitions*, 2022.

51 NERC, *Essential Reliability Services Task Force: Concept Paper on ERS that Characterizes BPS Reliability, October 2019*, https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Concept%20Paper.pdf.

52 Electric Power Research Institute, *Grid Services in the Distribution and Bulk Power Systems: A Guideline for Contemporary and Evolving Service Opportunities for Distributed Energy Resources, July 2021*, https://www.epri.com/research/products/000000003002022405.

53 Paul De Martini, *Bulk Power, Distribution, and Grid Edge Services Definitions, Newport Consulting, November 2023*, https://www.energy.gov/sites/default/files/2023-11/2023-11-01%20Grid%20Services%20Definitions%20nov%202023_optimized_0.pdf.

54 NERC IRPTF, *Fast Frequency Response Concepts and Bulk Power System Reliability Needs, 2020.*

55 De Martini, *Bulk Power, Distribution, and Grid Edge Services Definitions, 2023.*

Figure 7: Simplified Grid Services Taxonomy

This taxonomy includes grid services for the bulk power system, distribution system, and grid edge:

- **Bulk power system grid services** are those that meet the requirements of the transmission grid and maintain essential reliability across the electric system.
- **Distribution system grid services** are those that meet the requirements of the distribution grid and maintain essential reliability at distribution voltages.
- **Grid edge services** are those in relation to customer and community needs, including managing microgrid and islanded electric grids.

Some grid services (e.g., energy and capacity) are required across the bulk power system, the distribution system, and the grid edge. Given the overlap, descriptions of these grid services are not repeated at length in the following tables. The taxonomy also divides between energy and capacity services and essential reliability services (ERSs). ERSs are defined by the North American Electric Reliability Corporation (NERC) as the characteristics to reliably operate the electric grid. Ancillary services are a subset of ERSs, though the definition of ancillary services is jurisdiction-dependent and may change as markets provide more ERSs as ancillary services.[56]

56 NERC IRPTF, *Fast Frequency Response Concepts and Bulk Power System Reliability Needs, 2020*.

Foundational Questions

Which grid services can ADERs provide?

ADERs can provide nearly all the essential grid services that are required to run and maintain a reliable electricity service, though some characteristics of spinning generators are more challenging to provide, such as inertial response.[57] Dispatch mechanisms are as important to ADERs' performance as their technical capabilities; ADERs require clear demand signals, sufficient incentive structures, and well-defined contracts to ensure that the resources respond when needed.

The following section provides a high-level overview of grid services and how ADERs can meet these grid needs and then outlines how state cohorts identify and meet a range of these grid services today.

Bulk power system grid services

Energy and capacity are grid services from resources that inject power, reduce load, or consume energy. While individual DERs can provide energy and capacity services at the distribution level, ADERs can provide these services to the bulk power system as well. Some ADERs are also capable of providing essential grid reliability services that have historically depended on large fossil fuel assets. When considering ADERs for these grid services, the following considerations are important:

- **ADERs require advanced/smart inverters to provide certain essential reliability grid services:** Inverters are technologies that convert direct current (DC), which is the output of renewable generation such as solar panels, into alternating current (AC), which is required for the majority of the grid. Advanced inverters perform the same functions and can provide additional essential reliability grid services.[58]
- **Managers of ADERs will need to plan and prioritize the grid services they provide:** The ability of ADERs to provide reliability services will come at a cost to an individual DER's total energy production. For example, a solar PV system with an advanced inverter can provide fast frequency response if exporting less than its total capacity to the grid.
- **The need for grid services will evolve as the grid transitions toward renewables and ADERs:** For example, inverter-based resources, including ADERs, can detect and respond to changes in the energy system faster than fossil assets, which decreases the amount of inertia and the amount of inertia that is needed.[59]

57 Fossil fuel assets with large spinning masses provide inertial response that helps maintain the frequency of the grid. Though not deployed at scale yet, grid-forming (GFM) technology for inverter-based resources (e.g., wind, solar, batteries) are being explored as one solution to maintaining inertia in a high-renewables grid. GFMs, especially when paired with utility-scale batteries, are being tested today that, if proven, could enable ADERs to provide all essential grid services. For more information, please see Herman C. Trabish, "As Reliability Concerns with Renewables Rise, Upgrading Inverters Is Urgent, Analysts Say," **Utility Dive, 2024,** https://www.utilitydive.com/news/grid-forming-inverters-vital-protect-the-grid-solar-wind-batteries/702892/.

58 For more detailed information, please see NREL, "Advanced Power Electronics and Smart Inverters," https://www.nrel.gov/grid/power-electronics-inverters.html; Ujjwol Tamrakar, *Smart Inverter Functions and Features for Power System Parameter Estimation*, IEEE, January 2021, https://www.osti.gov/biblio/1854676/.

59 Paul Denholm, Trieu Mai, Rick Wallace Kenyon, Ben Kroposki, and Mark O'Malley, *Inertia and the Power Grid: A Guide Without the Spin, National Renewable Energy Laboratory, May 2020,* https://www.nrel.gov/docs/fy20osti/73856.pdf.

Table 5 describes bulk power system grid services and the role of ADERs in more detail.

Table 5: ADERs and Bulk Power System Grid Services

Type	Bulk Power System Grid Service	ADER Ability	ADERs Capable of Providing the Grid Service[60]: Generation DERs	Storage DERs	Demand DERs
Energy & Capacity	*Energy*: The amount of electricity a resource can provide (measured in megawatt-hours [MWh] or kilowatt-hours [kWh]). Providing energy to the grid is necessary to serve demand.	Individual DERs provide energy at the distribution level (e.g., residential solar PV). ADERs can provide energy to the bulk power system (e.g., aggregated EVs).	✔	✔	
	Energy Imbalance: The differential between scheduled and delivered energy over a one-hour time window.	ADERs are able to respond to energy imbalance in the bulk power system.	✔	✔	✔
	Capacity: The potential to generate or reduce electricity when needed (measured in megawatts [MW] or kilowatts [kW]). Grid operators use estimates of available capacity to plan how to supply energy at various increments of time (e.g., a day before, an hour before).	ADERs can meet capacity requirements by agreeing to provide energy needs for a future time. Forward planning is required and may include ADERs "load building" by demanding additional energy from the grid (e.g., charging energy storage) or "load reducing" by reducing ADER electric load (e.g., a smart thermostat demand response program). ADERs may contract months to years in advance for the provision of capacity to the bulk power system, and/or participate in capacity markets.	✔	✔	✔
	Transmission Capacity Infrastructure Relief: The use of grid resources to defer or avoid the reinforcement of the transmission grid.	If ADERs can provide transmission capacity management, they may be able to defer or avoid new transmission infrastructure build out.	✔	✔	✔
Essential Reliability Service[61]	*Regulating Reserve:* Resources with a rapid response time (minute to minute) are leveraged during normal operations to maintain the grid's operating frequency and regulate unintended fluctuations in generator output.	DERs, particularly variable renewables (e.g., wind and solar) can increase the need for regulating reserves due to impacts on net demand; ADERs can provide this grid service.	✔	✔	

60 ADER capabilities derived from Hawaiian Electric's Integrated Grid Planning docket; Hawaiian Electric, Docket No. 2018-0165, Instituting a Proceeding to Investigate Integrated Grid Planning, September 14, 2022, p. 70–71, https://www.hawaiianelectric.com/a/11407; and Michael Milligan, Sources of Grid Reliability, Science Direct, November 2019, https://www.sciencedirect.com/science/article/pii/S104061901830215X.

61 For another way to understand and map these different services, please see Paul Denholm, Yinong Sun, and Trieu Mai, *An Introduction to Grid Services: Concepts, Technical Requirements, and Provision from Wind*, NREL, 2019, https://www.nrel.gov/docs/fy19osti/73590.pdf, slide 12.

Type	Bulk Power System Grid Service	ADER Ability	ADERs Capable of Providing the Grid Service[60]		
			Generation DERs	Storage DERs	Demand DERs
Essential Reliability Service	*Inertial Response:* Instantaneous ability to respond to and slow down declines in frequency, enabling other frequency services to detect the issues and respond.	Currently, renewables and DERs cannot provide this exact service. However, leading pilots are testing if advanced inverters can inject energy instantaneously into the system, which could achieve the same outcome as traditional spinning generators.[62] This is commonly referred to as synthetic inertia.	✔	✔	
	Fast Frequency Response: Near-instantaneous energy injection following a frequency deviation to further slow the rate of change of frequency (ROCOF). Sometimes referred to as synthetic inertia.	ADERs with advanced inverters can already provide grid stabilizing services such as fast frequency and primary, secondary, and tertiary frequency responses.[63]	✔	✔	✔
	Primary Frequency Response: An automatic response that helps improve and stabilize the frequency.		✔	✔	✔
	Secondary and Tertiary Frequency Response: Additional tools maintain frequency. Secondary is provided by generators automatically; tertiary describes redispatch of new or additional generation.		✔	✔	✔
	Operating Reserves (Spinning): Operating reserves have active power capacity above firm demand to meet scheduled and unscheduled electric service disruptions. Spinning reserves consist of resources synchronized to the system to serve or remove load.	Operating reserves are typically distinguished by how quickly these resources can respond to a signal to inject or offload power after an event.[64] ADERs with smart inverters can already provide operating reserves, including spinning reserves, because these resources can ramp up or down quickly depending on the signal and need.	✔	✔	
	Operating Reserves (Non-Spinning): Offline operating reserves that are capable of coming online to respond to dispatch requests.		✔	✔	

62 Jeff St. John, "Solving the Renewable Energy Grid's Inertia Problem," Greentech Media, August 7, 2020, https://www.greentechmedia.com/squared/dispatches-from-the-grid-edge/solving-the-renewable-powered-grids-inertia-problem-with-advanced-inverters; Daniel Duckwitz, *What to Expect from Grid-Forming Inverters and How to Facilitate System Stability at 100% Renewables*, Energy Systems Integration Group, September 2023, https://www.esig.energy/what-to-expect-from-grid-forming-inverters-and-how-to-facilitate-system-stability-at-100-renewables/.

63 N. Ekneligoda, R. O'Keefe, and D. Ramasubramanian, *Case Studies of the Stability Benefit of Grid Forming Inverters on Energy Storage Facilities*, American Electric Power and Electric Power Research Institute, 2023, https://www.ercot.com/files/docs/2023/09/07/AEP_GFM_PreliminaryResults_Nishantha.pdf.

64 The term *spinning* refers to traditional fossil assets that were prepared to respond instantaneously by already "spinning" or rotating in synchronism with the grid. A typical timeframe would be within 10 minutes.

Type	Bulk Power System Grid Service	ADER Ability	ADERs Capable of Providing the Grid Service[60]		
			Generation DERs	Storage DERs	Demand DERs
Essential Reliability Service	*Operating Reserves (Tertiary):* Operating reserves used after spinning and non-spinning reserves and deployed to replenish depleted reserves after an event.		✔	✔	
	Reactive Power and Voltage Support: Reactive power is supplied independent of real power. Resources regulate voltage by supplying reactive power, thereby maximizing the transfer of active power.	ADERs cannot provide these services to the bulk power system today. Their ability to contribute these services to the distribution system is described in the table below.			
	Ramping: Resources that can modulate active power upward or downward within set time periods. Sometimes referred to as load following.	With the appropriate inverter technologies, EV charging can provide fast and accurate responses to the need to ramp load up or down.			
	Black Start: After an outage, some generators require power to restart; black start capabilities require starting without power to then provide power and energy to other power plants.	Ongoing trials are exploring how DERs can provide black start services after an outage.[65, 66]	✔	✔	✔

How are bulk power system grid services identified and met?

In states with organized markets and restructured utilities (Jade cohort), the ISO/RTO is responsible for balancing supply and demand and maintaining system reliability. All ISOs/RTOs have competitive markets where generators, including ADERs, can bid in energy services at various time increments (e.g., day ahead, hourly, or five minute). Some ISOs/RTOs (e.g., ISO New England, PJM, and New York ISO [NYISO]) also have markets to secure capacity.

Each ISO/RTO has a different suite of markets for procuring ERSs, and there are different definitions of services and qualification requirements. Typically, there are day-ahead and real-time markets to secure and schedule ancillary services. For example, for voltage support services, ISOs/RTOs contract directly with interconnected resources, and the associated costs to meet these grid needs are distributed among the loads.[67]

In states with organized markets and vertically integrated utilities (VIUs) where utilities can own generation assets (Coral cohort), utilities can use resource planning to evaluate the potential of ADERs to meet the energy and capacity needs for the given utility jurisdiction. To best understand if and how ADERs can meet grid

65 There is an ongoing project in the United Kingdom that is exploring, at various test sites, how DERs can be used to restore power to the national transmission system in the case of a total or partial shutdown. For more information, please see National Grid ESO, *Distributed ReStart: Demonstration of Black Start from DERs (Live Trials Report) Part 1*, December 2021, https://www.nationalgrideso.com/document/226951/download.

66 In Hawaii, this is considered a distribution system grid service only.

67 Energy Knowledge Base, "Voltage Support," accessed April 25, 2024, https://energyknowledgebase.com/topics/voltage-support.asp.

resource adequacy needs, utilities are increasingly integrating distribution system planning with bulk power system resource planning.[68]

In states outside of organized markets (Turquoise cohort), VIUs are responsible for maintaining reliability. VIUs use administrative mechanisms, including tariffs, contracts, and RFPs to procure a pre-determined quantity of ERSs likely needed.

Distribution system grid services

Individual and ADERs can provide the grid services necessary at the distribution system level. Similar to the bulk power system grid services, individual and ADERs require advanced or smart inverters to provide essential reliability services. Additional technologies are necessary for ADERs to provide resilience.

Table 6 describes distribution system grid services and the role of ADERs in more detail.

Table 6: ADERs and Distribution System Grid Services

Type	Distribution System Grid Service	ADER Ability	ADERs Capable of Providing the Grid Service[69]		
			Generation DERs	Storage DERs	Demand DERs
Energy & Capacity	*Energy*: Resources that produce active power in the distribution system (measured in MWh or kWh)	ADERs can provide energy to the distribution system; some ADERs can also draw down (consume) energy.	✔	✔	
	Capacity: Resources that can supply energy or reduce load to reduce net load where necessary on the distribution network.	If ADERs can provide distribution capacity management, they may be able to delay or avoid new distribution system infrastructure buildout.	✔	✔	✔
Essential Reliability Service	*Reactive Power and Voltage Support:* Similar to the parallel grid service at the bulk power system level, this grid service supplies reactive power to maintain voltage levels at the distribution level.	Smart inverters that are either directly controlled or autonomously operated can regulate voltage and provide reactive power.	✔	✔	
	Power Quality: Resources able to manage flicker and harmonics on the distribution system.	Smart inverters, other power electronics devices, and batteries can improve power quality.	✔	✔	
	Resilience:[70] Resources within a microgrid that support an electric service's ability to withstand, respond to, and rapidly recover from disruptions.[71]	ADERs, when equipped with islanding technologies, can provide resilience services to customers and the distribution network.	✔	✔[72]	

68 For more information about integrated distribution system planning practices, please see "Integrated Distribution System Planning," *LBL*, https://emp.lbl.gov/projects/integrated-distribution-system-planning.

69 ADERs capabilities derived from Hawaiian Electric's Integrated Grid Planning docket; Hawaiian Electric, Docket No. 2018-0165, p. 70–71; and Milligan, *Sources of Grid Reliability*, 2019.

70 Distribution Resilience services at the individual customer and community level are covered under "Grid Edge Services."

71 NREL, *Resilience Roadmap*, https://www.nrel.gov/resilience-planning-roadmap/.

72 Storage DERs can provide this service when they have islanding capabilities.

How are distribution system grid services identified?

There are currently 22 states that have integrated distribution planning processes underway at various levels of maturity and complexity.[73] Integrated distribution planning processes have the potential to identify more granular distribution-level grid needs, including identifying reliability and resilience requirements, needed infrastructure upgrades, and opportunities to avoid or defer grid investments by utilizing NWS that could comprise ADERs. By forecasting expected DER adoption scenarios, distribution planning also can help inform where there may be constraints to further DER interconnection, impacting the potential for ADERs to provide grid services at both the distribution and bulk system.

Grid edge services

Grid edge services explicitly serve individual customers and communities that are behind a metered grid connection (also referred to as "BTM") or as part of a microgrid, as opposed to the distribution or bulk power grids. Individual DERs typically provide the same services that are relevant for distribution systems (see previous section) to BTM customers and communities, with the exclusion of capacity.[74] In those cases, where multiple customers are located behind a single meter or microgrid islanding point, ADERs can provide these services. An example is a community microgrid.[75] However, most grid edge services are supplied by individual DER systems. Because individual DERs can provide services to individual customers, and ADERs can provide services to the distribution and bulk system, it is important to have clear plans to ensure resources do not face conflicting requirements at the same moment in time (e.g., if a customer intends to use their DER equipped with islanding technologies to supply backup power and power quality while the DER is called upon in an ADER program in that same instance to provide capacity services to the grid).

Which grid services do ADERs provide in the United States today?

While ADERs can provide a wide range of grid services, not all jurisdictions are leveraging these capabilities yet. Using ADERs to meet grid needs might require rule or process changes, technology upgrades, and further education of ADER capabilities. **Table 7** summarizes which grid services are currently provided in the United States by ADERs, along with an example of a program(s) that provides the grid service. It is important to note that the ADER landscape is changing rapidly, and Table 7 provides a snapshot of what is available in early 2024.

73 Joe Paladino, Integrated Distribution System Planning Status, Challenges, and Approaches, https://www.energy.gov/sites/default/files/2023-02/Integrated%20Distribution%20Systems%20Planning.pdf.

74 Capacity is not considered a Grid Edge Service because individual consumers do not typically estimate capacity of resources to defer or avoid infrastructure build out BTM. End users require energy services from their DER(s).

75 Schatz Energy Research Center, *Blue Lake Rancheria Microgrid Project Fact Sheet, 2018*, https://bluelakerancheria-nsn.gov/wp-content/uploads/2018/11/BLR_Microgrid_FactSheet.pdf.

Table 7: ADER Grid Services Provided Today

Service Category	Grid Service	Provided by ADERs in the U.S. as of early 2024?	Example
Bulk Power System Grid Services	Energy	Yes	Xcel Energy Solar Rewards Program[76]
	Energy Imbalance	No	
	Capacity	Yes	National Grid Connected Solutions Bring Your Own Device (BYOD) Program in Massachusetts[77] Central Hudson NWS in New York[78] Holy Cross Power Plus Program[79]
	Regulated Reserves	No	
	Inertial Response	No[80]	
	Fast Frequency Response	Yes	Hawaiian Electric Power Partners and Energy Scout Programs[81]
	Primary Frequency Response	Yes	ERCOT Demand Response in Texas[82]
	Secondary and Tertiary Frequency Response	Yes	NYISO Demand-Side Ancillary Service Program in New York[83]
	Reactive Power and Voltage Support (System)	Yes	Mosaic Power, Multiple States[84]
	Ramping Reserves	No	
	Black Start	No	Currently being field tested[85]

76 Xcel Energy, "Xcel Energy Solar Rewards Program," accessed April 25, 2024, https://co.my.xcelenergy.com/s/renewable/solar-rewards.

77 Applied Economics Clinic, *Energy Storage for Winter Grid Reliability: How Batteries Become the Low-Cost Solution for Power Assurance in Massachusetts*, December 2021, https://www.cleanegroup.org/wp-content/uploads/Energy-Storage-for-Winter-Reliability.pdf.

78 Central Hudson, "Non-Wires Alternative Opportunities," accessed April 25, 2024, https://www.cenhud.com/en/contractors/non-wires-alternative-opportunities/.

79 Holy Cross Energy, "Increase Your Home's Resilience with Power+," accessed April 25, 2024, https://www.holycross.com/powerplus/.

80 Other countries, including Australia and Great Britain's National Grid Electricity System Operator, are demonstrating that synthetic inertia can enable grid stability. For more information, please see Roger Riley, *Australia Leans in on Synthetic Inertia for Grid Stability*, PSC Consulting, 2021, https://www.pscconsulting.com/australia-leans-in-on-synthetic-inertia-for-grid-stability/; and "National Grid ESO Deploys GE Digital Effective Inertia Metering & Forecasting Solution," *Business Wire*, 2021, https://www.businesswire.com/news/home/20220407005608/en/National-Grid-ESO-Deploys-GE-Digital-Effective-Inertia-Metering-Forecasting-Solution.

81 Hawaiian Electric, "Customer Incentive Programs," accessed April 25, 2024, https://www.hawaiianelectric.com/products-and-services/customer-incentive-programs - :~:text=Fast Frequency Response (FFR) -,being drawn from the grid.

82 ERCOT, "Load Resource Participation in the ERCOT Markets," accessed April 25, 2024, https://www.ercot.com/services/programs/load/laar.

83 Vijaya Ganugula and Michael Ferrari, "DER Real-Time Telemetry and Alternate Telemetry Approach for Small DER," NYISO Market Issues Working Group, September 28, 2018, https://www.nyiso.com/documents/20142/2549675/DER%206-Second%20Telemetry%20-%20MIWG%2020180928%20MIWG.pdf/e4309d38-8f57-2dc8-7328-5c2dc519b198.

84 Mosaic Power Energy, "When for Electric Water Heaters," accessed April 25, 2024, https://mosaicpower.com/when-for-electric-water-heaters.

85 National Grid ESO, "Distributed ReStart," accessed April 25, 2024, https://www.nationalgrideso.com/future-energy/projects/distributed-restart.

Service Category	Grid Service	Provided by ADERs in the U.S. as of early 2024?	Example
Distribution Grid Services	Energy	No	Net Energy Metering (NEM)[86]
	Distribution Capacity	Yes	Consumers Energy NWS in Michigan[87]
	Distribution Level Voltage Reactive Power	No	
	Power Quality	No	
	Resilience	Yes	Energy Vault in California[88]
Grid Edge Services	Energy	Yes	Self-Consumption of Solar PV
	Distribution Voltage-Reactive Power	No	
	Power Quality	No	
	Resilience	Yes	Green Mountain Power (GMP) BYOD Program in Vermont[89]

What proportion of grid services in my state could/should come from ADERs?

State policymakers may choose to set specific targets for ADER grid services to incentivize the utilization of ADERs for grid services. Targets can give aggregators and other relevant stakeholders confidence that there will be a market for ADERs and encourage utilities to integrate ADERs because of the additional benefits they may provide over traditional solutions. Policymakers may choose to set a target that is reasonable, attainable, and informed by current priorities and relevant contexts such as cost. Policymakers can also iterate on it over time. As an example, California legislators recently introduced a bill that requires the California PUC to consider defining a procurement target for load-serving entities to procure a portion of their monthly system resource adequacy obligation from VPPs by 2035.[90]

Alternatively, state policymakers may instead wish to pursue a "level playing field" approach, whereby ADERs and traditional grid service providers compete in a technology neutral process. In states with VIUs, this is commonly conducted using "all-source procurement." Utilities leverage resource planning, and in some states, distribution planning or integrated system planning, to determine a set of grid needs (typically capacity, energy, reserves, and other resource attributes) and suppliers bid combinations of resources that can meet the pre-determined needs. For restructured jurisdictions (Jade cohort), ISOs/RTOs can also develop and refine market rules to neutrally select technologies to provide essential services at market prices.

86 Energy Metering allows customers to export energy to the distribution system. For more information, please see Solar Energy Industries Association, "Net Metering," https://www.seia.org/initiatives/net-metering.

87 Steve Cowell, E4 The Future; Tiger Adolf, PLMA; Brenda Chew, SEPA; Marie Schnitzer, National Grid; Damei Jack, Con Edison; and Sarah Arison, Bonneville Power Administration, "Non-Wires Alternatives: Case Studies from Leading U.S. Projects," PLMA, 2018, https://www.peakload.org/assets/38thConf/Non-Wires-Alternatives-Projects.pdf.

88 "PG&E Teams With Energy Vault to Build and Operate the Largest Green Hydrogen Long-Duration Energy Storage System in the U.S.," *Business Wire*, January 5, 2023, https://www.businesswire.com/news/home/20230105005452/en/PGE-Teams-With-Energy-Vault-to-Build-and-Operate-the-Largest-Green-Hydrogen-Long-Duration-Energy-Storage-System-in-the-U.S.

89 GMP specifically cited resilience as a reason for wanting to expand its BYOD program. For more information, please see GMP, "GMP's Request to Expand Customer Access to Cost-Effective Home Energy Storage Through Popular Powerwall and BYOD Battery Programs is Approved," August 2023, https://greenmountainpower.com/news/gmps-request-to-expand-customer-access-to-cost-effective-home-energy-storage-is-approved/.

90 California Senate Bill 1305, Electricity: Virtual Power Plant Procurement, California Legislature, 2024, https://legiscan.com/CA/text/SB1305/id/2962529.

How can ADERs provide multiple grid services?

ADERs can be co-optimized to provide multiple grid services.[91, 92, 93] There are three ways to do this:

1. **Time-differentiated multiple-use applications (also known as "Jumping"):** The DER provides different services at different time periods. For example, a battery storage resource could be dispatched to provide bulk capacity grid services in the summer and dispatched in the winter to provide distribution capacity grid benefits. As long as the timing need of the two grid services does not overlap, there is no trade-off between using the ADER for one grid service over the other.
2. **Capacity-differentiated multiple-use applications (also known as "Splitting"):** The DER provides two grid services at the same time but must split its MW or MWh value between the two grid services. For example, a customer's battery may be partially discharged to provide a peak capacity benefit, while still reserving a portion of the battery to provide the customer with backup power in case of an outage.
3. **Simultaneous multiple-use applications (also known as "Co-Delivery"):** The DER provides multiple grid services at the same time when it is dispatched. For example, a battery may be dispatched to provide both bulk capacity grid benefits and distribution grid benefits if both are needed at the same time. There is no trade-off between the two grid services. Co-delivery only occurs where multiple grid services are needed. If multiple resources are dispatched to serve bulk capacity needs, there would only be an additional distribution benefit for resources in areas where there is a distribution capacity constraint.

To successfully stack grid services together, it is important to consider grid service needs, whether the service windows are aligned, and the monitoring and verification (M&V) required to identify the grid services provided. One caution associated with the stacking of grid services is "double counting" a resource. Typically, a resource is double counted when it is compensated twice for providing a single grid service. For example, if a generating DER is paid for the energy it produces, and the same energy is used to reduce a customer's load profile, the customer should not be compensated twice for that service. Double counting for ADER grid services is most commonly an issue when DERs are used as both demand (customer savings on a retail rate) and supply (customer is part of an ADER participating in the wholesale market) resources. Double counting is generally prohibited but requires market and grid service monitoring and enforcement from PUCs.

How can grid services be coordinated?

As noted above, when dispatching grid services, there may be a need to choose which grid services to provide at certain times. While some grid services can be dispatched without any trade-offs (jumping or co-delivery), in other cases, providing two or more grid services may require a trade-off (splitting). These potentially conflicting services may need to be balanced against one another in a practice sometimes referred to as "deconflicting dispatch," which can be resolved through mechanisms such as "primacy rules." This typically occurs when distribution grid needs differ from bulk power system grid needs, or when customer needs differ from grid needs. While this is a concept that is still being studied, there are three considerations for grid operators and utilities when coordinating between grid services:

91 California Public Utilities Commission (CPUC), Docket No. D.18-01-003, "Decision on Multiple-Use Application Issues," January 11, 2018, docs.cpuc.ca.gov/PublishedDocs/Published/G000/M206/K462/206462341.PDF.

92 The Lumen report discusses the implementation of the CPUC Multiple Use Applications process in detail. Aydin Mariko Geronimo and Cevat Onur Aydin, *California Public Utilities Commission Energy Storage Procurement Study*, Lumen Energy Strategy, LLC, prepared for the CPUC, May 31, 2023, www.lumenenergystrategy.com/energystorage.

93 Dan Starman et al., *Revenue Stacking for Flexibility: A Report for National Grid Electricity Distribution, Cornwall Insight, December 2023*, https://www.flexiblepower.co.uk/downloads/1150.

1. **Communication:** In places where DER penetration is increasing, studies recommend increased communication between parties seeking to dispatch bulk power system, distribution, and grid edge services. For example, this may be the ISO/RTO and the distribution operator for determining when and where ADERs should be dispatched.[94]

2. **Clear definition of how ADERs need to be dispatched to provide a grid service:** When dispatching ADERs to provide a grid service, consider:

    a. **How often a resource is dispatched.** For example, a demand response program may call 5 or 10 events per summer depending on the needs of the grid whereas other programs may require daily dispatch or even hourly dispatches for essential reliability services.

    b. **How long the resource is dispatched for.** For example, BTM batteries can be dispatched for mere moments, hours, or at the maximum power for the full duration of their capacity.

    c. **When the resource is dispatched.** For example, BTM battery storage could be dispatched from 1 to 3 p.m. or from 6 to 8 p.m. depending on the needs of the grid.

    The dispatch requirements for a DER may be different if it is being used to meet distribution needs compared to when it is being used to meet bulk power system needs. If these are clearly defined for each grid service, policymakers can determine if a single DER is able to provide multiple grid services, or if there are trade-offs between providing a distribution grid service and a bulk system grid service. As an illustrative example, an ADER system that is dispatched during peak hours, 5 to 7 p.m., Monday through Friday, may not be able to provide essential reliability services to the bulk power system during those hours, but may be available outside that time window.

3. **Clear definitions of how to participate within and across ADER programs:** If trying to provide multiple grid services, an option is to create separate programs for each grid service. For example, if trying to meet both distribution needs and bulk system needs, two separate programs can be set up with two separate sets of dispatch windows, duration rules, and event rules.[95] If a single DER is being used to provide multiple grid services, it will be necessary to create rules that prioritize one grid service over the other.[96, 97] It may also be possible to create a combined program that coordinates dispatch for multiple grid services.

94 Gridworks performed one such study in California, where transmission operators communicate with system operators and distribution operators, but currently there is no way for distribution and system operators to communicate directly. The study recommended that system operators and distribution operators develop a direct line of communication because greater DER penetration starts to have a larger impact on the distribution system; *Coordination of Transmission and Distribution Operations in A High Distributed Energy Resource Electric Grid, Gridworks,* June 2017, https://gridworks.org/wp-content/uploads/2017/01/Gridworks_CoordinationTransmission.pdf.

95 Con Edison for example, has a Distribution Load Relief Program and a Commercial System Load Relief Program; ConEdison, "Smart Usage Rewards for Aggregators or Direct Enrollees," accessed April 25, 2024, https://www.coned.com/en/save-money/rebates-incentives-tax-credits/rebates-incentives-tax-credits-for-commercial-industrial-buildings-customers/smart-usage-rewards.

96 A study at Pacific Gas & Electric found that while batteries were capable of providing distribution services and bidding into the wholesale energy market, there would need to be rules establishing priority between the two systems for the solution to be scalable; Kirsten Ardani, Eric O'Shaughnessy, and Paul Schwabe, *Coordinating Distributed Energy Resources for a Grid Service: A Case Study of Pacific Gas and Electric, November 2018,* https://www.nrel.gov/docs/fy19osti/72108.pdf.

97 CPUC, Docket No. D.18-01-003, 2018.

Focus area: Reliability of ADERs: How do ADERs compare to traditional solutions?

Although DER technologies are not new, the relatively new technology configurations, aggregations, and applications have expanded the role these technologies can play in the energy system. Many utilities, system operators, and policymakers still hold questions about whether ADERs are as reliable as traditional solutions when it comes to providing grid services.

While real-world examples are still emerging, several groups have completed research to explore how ADERs perform compared to traditional solutions in terms of their ability to provide grid services. The Brattle Group conducted an analysis modeling and comparing a 400 MW VPP to a natural gas peaker plant and utility scale battery storage. Brattle's analysis found that the VPP could perform just as reliably as the peaker plant at 40–60% of the cost of the two alternatives studied.[98]

Traditional solutions such as gas power plants also have a history of failure in extreme weather events when they are most needed due to issues such as frozen equipment.[99] With a distributed probability of delivery rather than a single point of failure, ADERs are more resilient to extreme weather events.

However, it is important to design and implement ADERs effectively to ensure that they are reliable. If resources such as demand response are used too frequently, they can lead to customer fatigue and unenrollment from the program.[100] Similarly, new technologies, such as EV-to-grid integration, will need to continue to be tested as pilots and be iterated upon before they can provide reliable value. Other safeguards, such as penalties for non-performance, can also be used to help ensure that ADERs are reliable.

Finally, ADERs can be compared to traditional solutions when assessing their overall reliability. Capacity accreditation methodologies, such as effective load carrying capacity (ELCC), can compare these resources side by side and help to select the most reliable resource.[101]

98 Ryan Hledik and Kate Peters, *Real Reliability: The Value of Virtual Power*, Brattle, May 2023, https://www.brattle.com/wp-content/uploads/2023/04/Real-Reliability-The-Value-of-Virtual-Power_5.3.2023.pdf.

99 Union of Concerned Scientists, "How Gas Plants Fail and Lead to Power Outages in Extreme Winter Conditions," accessed April 25, 2024, https://blog.ucsusa.org/paul-arbaje/how-gas-plants-fail-and-lead-to-power-outages-in-extreme-winter-weather/.

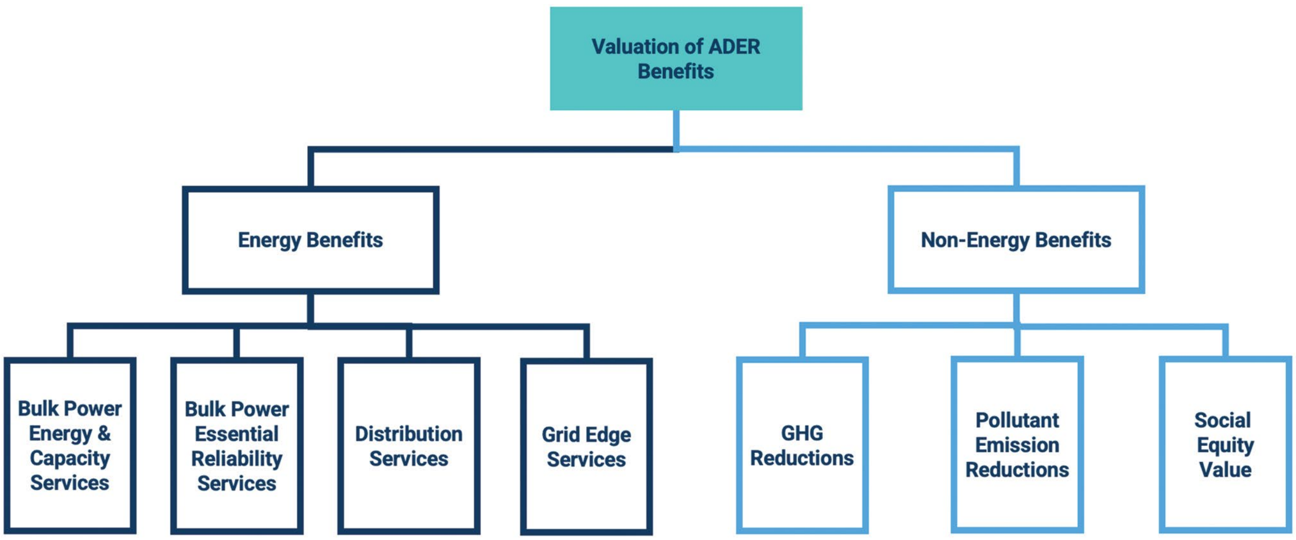
100 Zinyi Chen et al., "Strategic Interaction to Reduce Customer Fatigue in Load Aggregation," *The 4th International Conference on Electrical Engineering and Green Energy (CEEGE), June 10–13, 2021, Munich, Germany,* November 2021, https://www.sciencedirect.com/science/article/pii/S2352484721006417.

101 Union of Concerned Scientists, "How Reliable Are Gas Power Plants? What ICAP, UCAP, and ELCC Tell Us," accessed April 25, 2024, https://blog.ucsusa.org/mark-specht/how-reliable-are-gas-power-plants-what-icap-ucap-and-elcc-tell-us/.

ADER Valuation

ADER valuation provides the information needed to design programs, market rules, and rates that align the interests of ADER participants, utilities, ratepayers, policymakers, and other stakeholders. This section discusses different approaches to establishing the monetary and non-monetary value of ADER grid services to DER owners, utilities, ISOs/RTOs, and the wider energy system. It also outlines how ADER valuation can inform pricing and program compensation mechanisms discussed in more detail in the "ADER Compensation" section. This section does not include other factors that will impact the compensation received by aggregators and DER owners providing grid services (i.e., baselining methodologies, performance incentives, and penalties) because these factors are discussed under the section, "ADER Compensation." **Figure 8** summarizes the benefits that are discussed in this section.

Figure 8: Valuation of ADER Benefits



ADER value, as defined in this report, refers to the gross benefits of an ADER to the grid or to society and does not factor in the cost of operating an ADER. Once the benefits of an ADER are determined, they can be compared to the costs of implementing the ADER in a cost-effectiveness assessment. Cost-effectiveness assessments are described in more detail at the end of this section.

Overview of ADER Valuation Methods, by Cohort

Table 8 summarizes the valuation methodologies used for each grid service and non-energy benefit, broken out by cohort. Each methodology is described in more detail in the remainder of this section, along with how the methodologies vary for each cohort. Generally, the methodologies are broken out based on whether or not the cohort has an organized market, as direct participation in organized markets can establish the value of many bulk power grid services. Distribution and grid edge services, which do not currently have markets in the United States, do not have different valuation methods by cohort. However, whether utilities in a state undertake distribution system planning can impact the accuracy and granularity of distribution values.

Table 8: Summary of Valuation Methodologies Across Cohorts

			Cohort		
Value Category			Outside organized markets; utilities own generation assets (Turquoise cohort)	Within organized markets; utilities do not own generation assets (Jade cohort)	Within organized markets; utilities own generation assets (Coral cohort)
Energy Benefits	Energy & Capacity Grid Services	Bulk Power	Based on avoided costs or least cost solution, including ADERs.	Based on market values.	
		Distribution	Based on avoided grid upgrade costs.		
		Grid Edge	Based on customer benefits from service, typically a reduction in bills.		
	Essential Reliability Services	Bulk Power	Based on avoided costs or least cost solution, including ADERs.	Based on market values where they exist. Otherwise based on avoided costs.	
		Distribution	Ancillary service and reliability values based on avoided grid upgrade costs. Resilience values based on value of lost load or reliability improvements.		
		Grid Edge	Based on customer benefits from service, typically through avoided outage costs for the customer.		
Non-Energy Benefits	Reduction in GHG Emissions and Pollutant Emissions, Social Equity		Modeled based on state-specific goals and societal impact assumptions or use values estimated by the EPA.		

Foundational Questions

How are ADER energy benefits valued?

Historically, counterfactual analyses have been used to estimate the value of DER energy benefits. As some markets begin to allow direct ADER participation, values of some ADER grid services are now set by the market rather than using a counterfactual analysis. We cover the valuation methods currently used in ADER landscape in this document.[102] The valuation landscape will continue to evolve as more DERs are integrated into the grid and the grid services that these DERs provide continue to expand. As DERs become more prominent, there will also be more instances where ADER solutions compete with each other in addition to competing with traditional grid solutions, incentivizing them to maximize benefits and minimize costs.

Estimating avoided costs—counterfactual analyses

A counterfactual scenario is the course of action that would have happened had no specific change or service been delivered. Counterfactual analyses can be used to estimate both the impact of an ADER (what would have happened to the grid in the absence of an ADER) as well as the grid service provided by an ADER (what would have been needed to provide the grid service in the absence of an ADER). In this section, we examine

102 Another source of the common methods for determining the economic value of DERs is the SEE Action Report: Tom Eckman, Lisa Schwartz, and Greg Leventis, *Determining Utility System Value of Demand Flexibility from Grid-Interactive Efficient Buildings, State and Local Energy Efficiency Action Network*, April 2020, https://live-etabiblio.pantheonsite.io/sites/default/files/bto-see-action-gebs-valuation-20200410.pdf.

the latter.[103] In the case of ADER grid services, counterfactual scenarios are usually traditional generation or new grid infrastructure.

The costs of implementing a counterfactual scenario are also known as "avoided costs," or the cost avoided by implementing the ADER solution. It should be noted that avoided costs, as defined in this report, do not account for the cost of implementing ADERs. When comparing traditional solutions to ADER solutions, the costs of implementing each solution are subtracted from the benefits to estimate the "net benefits." The net benefits are then compared to decide upon which solution is more cost-effective to implement. More detail on the costs and benefits considered when calculating net benefits and overall resource cost-effectiveness is covered at the end of this section.

To quantify the value of ADER grid services using a counterfactual analysis, an accurate counterfactual scenario is needed to:

- Calculate the "cost to beat" of traditional solutions;
- Calculate the incremental benefits of ADER grid services against the traditional solution baseline; and
- Provide an indication of the unit value of grid services for monetary quantification (this is further discussed for grid services in organized markets [Coral and Jade cohorts]).

Estimating value using market prices

In circumstances where ADERs can participate directly in the market, a counterfactual analysis is not needed. ADERs are able to compete directly with the other resources, and the value of the grid service is based on the equilibrium set between the willing buyers and willing sellers of the grid service. The timing and frequency at which the resource is dispatched is determined by the market. We explore how different grid services are valued in different markets in the remainder of this section.

How are energy and capacity grid services for bulk power systems valued?

Table 9 summarizes which benefits have established methods for valuation and are covered in this section.

Table 9: Summary of Bulk Power Energy and Capacity Services Valued

Type	Bulk Power System Grid Service	Established Valuation Method Covered in This Section
Energy & Capacity	Energy	✔
	Energy Imbalance	
	Capacity	✔

In Organized Markets (Coral and Jade Cohorts)

Grid service values can be derived from the markets in which traditional resources have participated. While the exact valuation method will vary depending on the market and the state, we provide some examples of how ADERs are currently valued in market contexts.[104]

Both historical analysis of similar circumstances and forward-looking market value curves (i.e., day-ahead wholesale market clearing prices) can be used to inform the value of grid services.

103 The impact of an ADER on the grid is typically measured only when an ADER is dispatched or after an ADER is implemented. It is a measure of how well the ADER was able to provide the grid services valued in this section. Therefore, it is included in the compensation section, which covers how ADER implementers and participants can be compensated for providing grid services.

104 Further information on how to estimate generation capacity using markets can be found in Section 3.2.2., National Energy Screening Project, *Methods, Tools, and Resources: An Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis*, March 2022, https://www.nationalenergyscreeningproject.org/wp-content/uploads/2022/03/NSPM_Methods-Tools-Resources.pdf.

- For example, the *California Avoided Cost Calculator* and the *Avoided Energy Supply Components in New England* reports both provide publicly available capacity values based on market forecasts.[105]
- Another option is to estimate the cost of new entry (CONE), which is an estimate of the capacity revenue needed by a new generator in its first year of operation to make it economically viable in the market.[106]

In circumstances where ADERs can or will be able to compete directly in existing wholesale energy, capacity, and ancillary service markets, separate guide prices are not needed, and ADERs can simply compete as another market participant. In this case, the value of the grid service is determined by demand and supply of the market. For example, ISO New England has a Forward Capacity Market that ADERs can bid into.[107]

Outside of Organized Markets (Turquoise Cohort)

Outside of organized markets, utilities typically set suitable values for grid services provided by ADERs relative to building new generation assets or calling on generation assets already owned or procured by the utility. There are multiple approaches to estimating ADER generation capacity and energy values.

To determine the value provided by ADERs, utilities first develop a load forecast to determine their grid needs. For capacity and energy, this typically consists of determining if there are any system-level grid constraints based on the expected demand and current supply mix for each hour of the forecast year.

In determining the system needs, one option to define the value is to calculate the cost of meeting grid needs using traditional solutions, such as building out a new generation asset or utilizing an existing asset. The value of an ADER is the "avoided cost" of relying on the traditional solutions. The avoided cost is often accompanied with information about the quantity and timing of ADER implementation to successfully avoid the traditional solution.[108] The avoided cost is typically expressed in a $/kW, $/kWh, $/MW, or $/MWh value.

Alternatively, the utility can optimize the entire energy portfolio with and without ADER solutions and select the overall least cost solution that meets their grid needs. The ADER procurement targets are then based on the least cost portfolio solution that is developed. The ADER competes alongside traditional solutions and its avoided cost is based on the marginal cost of providing an incremental unit of the grid service.[109] The utility can also optimize an energy portfolio but may have specific priority policy outcomes (e.g., renewable portfolio standards, social equity) that influence the optimization.[110]

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105 Energy + Environmental Economics (E3), "Avoided Cost Calculator for Distributed Energy Resources (DER)," accessed April 25, 2024, https://www.ethree.com/public_proceedings/energy-efficiency-calculator/; Synapse Energy Economics, Inc., *Avoided Energy Supply Components in New England@ 2021 Report, March 15, 2021*, https://www.synapse-energy.com/sites/default/files/AESC%202021.pdf.

106 Midcontinent Independent System Operator (MISO), for example, estimates the CONE for each zone. MISO, *MISO Cost of New Entry (CONE) Planning Year 2023/2024, October 12, 2022*, https://cdn.misoenergy.org/20221012%20RASC%20Item%2004c%20CONE%20Update626542.pdf.

107 ISO New England, "About the FCM and Its Auctions," accessed on April 25, 2024, https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/about-the-fcm-and-its-auctions.

108 Colorado, for example, based their avoided generation cost on a combustion turbine's capital and operations and maintenance costs. See Task 3 of their Distributed Solar Generation Report, Xcel Energy Services, Inc., *Costs and Benefits of Distributed Solar Generation in the Public Service Company of Colorado System: Study Report in Response to Colorado Utilities Commission Decision No. C09-1223, May 23, 2013*, https://psc.ky.gov/pscecf/2020-00174/dspenard%40strobobarkley.com/03162021072217/2021.03.16_kyseia_inskeep_2_table_1_footnote_21.pdf.

109 Hawaii, for example, uses as "shadow price" to determine their avoided costs, which are analogous to market clearing prices for procuring an equivalent service in a market context. Public Utilities Commission of the State of Hawaii, Section 3.8.1.2, Docket No. 2018-0165, "Exhibit 1: Hawaiian Electric: Grid Needs Assessment & Solution Evaluation Methodology," September 2022, https://www.hawaiianelectric.com/a/11407.

110 Please see 'How Priority Policy Outcomes Impact ADER Policy Development' for additional detail on how policy priority outcomes can be incorporated.

How are essential reliability services for bulk power systems valued?

Table 10 summarizes which benefits have established methods for valuation and are covered in this section. Many of the essential reliability service grid services fall under "ancillary services," which are required to maintain grid stability. While individual markets may vary in terms of the ancillary services included, the services with an "X" in the table above can currently participate in some ancillary service markets in the United States or are valued as an ancillary service by some states. The grid services that are not marked with an "X" are relatively new or are not commonly used for ADERs and so do not have an established valuation method.

Table 10: Summary of Essential Reliability Services Valued

Type	Bulk Power System Grid Service	Established Valuation Method Covered in This Section
Essential Reliability Service	Regulating Reserve	✔
	Inertial Response	✔
	Fast Frequency Response	✔
	Primary Frequency Response	✔
	Secondary and Tertiary Frequency Response	
	Operating Reserves (Spinning)	✔
	Operating Reserves (Non-Spinning)	✔
	Operating Reserves (Tertiary)	
	Reactive Power and Voltage Support	✔
	Ramping	✔
	Black Start	

In Organized Markets (Coral and Jade Cohorts)

In some jurisdictions, ISOs/RTOs run markets for reliability grid services, such as PJM's ancillary service markets for regulation and reserve.[111] Like energy and capacity grid service valuation, these historical or forward-looking market values can be used to estimate value for specific ADER grid services, or ADERs can participate in these markets directly and have their value determined by the market.

Outside of Organized Markets (Turquoise Cohort)

Similar to energy and capacity grid service valuation, to determine the value of ancillary services provided by ADERs, utilities can first develop a load forecast to determine their grid needs. The utility will then determine the cost of meeting grid needs using traditional solutions, such as utilizing an existing asset or investing in new generation or infrastructure. Since utilizing ADERs allows the utility to avoid using a traditional solution, the value is calculated as the "avoided cost" of relying on the traditional solutions.[112]

How are distribution services valued?

Table 11 summarizes the distribution services with established valuation methods covered in this section. Distribution capacity is the most commonly valued distribution grid service. Reactive power and voltage

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111 PJM, "Ancillary Service Market," accessed April 25, 2024, https://learn.pjm.com/three-priorities/buying-and-selling-energy/ancillary-services-market.aspx#:~:text=Ancillary%20services%20help%20balance%20the,ancillary%20services%3A%20regulation%20and%20reserves.

112 For example, Hawaii used the EnCompass model to derive grid needs and evaluate solutions. Public Utilities Commission of the State of Hawaii, Docket No. 2018-0165, "Exhibit 1: Hawaiian Electric: Grid Needs Assessment & Solution Evaluation Methodology," 2022.

support can be valued as ancillary services in markets at the bulk system level, but there are currently no distribution markets for these services in the United States, and there is currently no established method for valuing these services outside of markets. Similarly, resilience at the distribution level is not very commonly modeled, although potential modeling metrics are described in the following.

Table 11: Summary of Distribution Services Valued

Type	Distribution System Grid Service	Established Valuation Method Covered in this Section
Energy & Capacity	Energy	
	Capacity	✔
Essential Reliability Service	Reactive Power and Voltage Support	
	Power Quality	
	Resilience[113]	✔

Distribution capacity refers to the distribution infrastructure needed to meet customer peak demand. ADERs can defer the need to invest in distribution infrastructure by reducing net load during peak hours. Distribution capacity value can be calculated at a systemwide level or at specific locations. Both approaches can be integrated into electricity system planning.[114]

To calculate distribution capacity value at a system level, the utility can estimate the marginal cost of new infrastructure associated with load growth based on historical data.[115] It can also be obtained from marginal cost-of-service studies, which estimate the marginal distribution cost associated with a change in ADER peak load.[116]

To calculate distribution capacity value at a specific location, the utility can estimate the infrastructure investment that can be avoided through NWS. The value of the avoided cost is the present value of the deferred investment of the traditional utility infrastructure solution.[117] Utilities can conduct systematic studies to assess the locational value of DERs as a part of the utility distribution planning process.[118] However, it is important to note that there is also a need for more granularity in terms of both data and value when estimating location-specific value. For example, New York's value stack credit for ADER compensation varies by location.[119]

113 Distribution Resilience services at the individual customer and community level are covered under "Grid Edge Services."

114 LBL goes into greater detail on the difference between system-wide and location-specific value; LBL, "Locational Value of Distributed Energy Resources," accessed April 25, 2024, https://emp.lbl.gov/publications/locational-value-distributed-energy.

115 Minnesota, for example, forecasts load growth with and without its energy efficiency programs and estimates the investments on the distribution system with and without its energy efficiency plan. The difference between the two investments is then divided by the total peak kW reduction provided by energy efficiency to get a $/kW value; Minnesota Department of Commerce, Docket No. E999/CIP-16-541, "Minnesota Transmission and Distribution Avoided Cost Study: Xcel Energy, Minnesota Power, Otter Tail Power Company with The Mendota Group, LLC, and Energy & Environmental Economics (Third Party Evaluator)," July 31, 2017, https://mendotagroup.com/wp-content/uploads/2018/01/TransmissionandDistributionAvoidedCostStudy.pdf.

116 ConEdison, for example, uses a marginal cost of service study to estimate its avoided distribution costs; ConEdison, *Electric Benefit Cost Analysis Handbook Version 3.0, July 2020,* https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-M-0412.

117 Rhode Island, for example, bases its Non Wires Alternative value on the "approximate value," or the net present value of the deferral value of the otherwise-needed local wires investment option. Rhode Island Public Utility Commission, Docket No. 5080, "National Grid Comments: 2021–2023 System Reliability Procurement Three-Year Plan," November 20, 2020, p. 18, https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/5080-NGrid-SRP-2021-2023-Three-Year-Plan%2811-20-2020%29V1.pdf.

118 LBL, "Locational Value of Distributed Energy Resources," accessed on April 25, 2024, https://emp.lbl.gov/publications/locational-value-distributed-energy.

119 Joint Utilities of New York, "Value of Distributed Energy Resources (VDER)," accessed on April 25, 2024, https://jointutilitiesofny.org/distributed-generation/VDER.

Focus area: Non-Wires Solutions (NWS)

Using ADER grid services to defer or avoid new transmission and distribution grid assets is commonly referred to as NWS. Utilities can leverage NWS to defer or avoid grid assets when NWS are cheaper than traditional infrastructure solutions to reduce overall system costs. In instances of deferral, NWS may also provide a utility with an opportunity to increase its certainty of the most appropriate sizing of the grid upgrade required as more accurate forecasts become available during the deferral period.

NWS have a readily available counterfactual cost, the capital and operational costs of building a new grid asset.[120] This value can be used to determine the baseline to compare NWS to and when such operational grid services can be more economically efficient than traditional grid build. It is important to factor in the annual costs of maintaining NWS in this calculation. The cost ceiling can be used in the development of programs or prices for demand flexibility, for example, as outlined in the "ADER Compensation" section.

Distribution Resilience

Resilience services can be valued by accounting for the capital and operational cost benefits of avoided interruptions and outages. The value calculations can be based on improvements to reliability metrics such as System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI), though these metrics are based on the deemed social and economic costs of interruptions and outages, which requires a value to be tied to the reliability improvement.[121] One way to estimate the value of reliability improvements is to estimate the Value of Lost Load (VoLL) and use this as the counterfactual "cost to beat" for improving a utility's overall reliability.[122] This means grid services provided under this cost ceiling are economically efficient in mitigating interruptions and outages. At present, a VoLL is not widely used in resilience service value quantification, though it is included in some utility BCAs.

How are grid edge services valued?

Table 12 summarizes the grid edge services with established valuation methods covered in this section. As grid edge services focus on benefits BTM, the benefits are most often direct energy benefits (e.g., reductions in energy bills) and resilience (avoided outages by customers). Other benefits such as reactive power and voltage support can occur BTM, but are difficult to quantify as they occur on an individual basis.

Table 12: Summary of Grid Edge Services Valued

Type	Grid Edge Service	Established Valuation Method Covered in this Section
Energy & Capacity	Energy	✔
Essential Reliability Service	Reactive Power and Voltage Support	
	Power Quality	
	Resilience	✔

120 See the locational value methodology for estimating the avoided distribution capacity cost described above.

121 ConEdison's Cost Benefit Handbook defines resiliency benefits based on its net avoided restoration costs. Changes in crew costs and expenses are calculated as a function of SAIDI and CAIDI; ConEdison, *Electric Benefit Cost Analysis Handbook, 2020.*

122 LBL has considered the factors in appropriately defining a VoLL; Will Gorman, "The Quest to Quantify the Value of Load: A Review of the Economics of Power Outages," *The Electricity Journal* 35, no. 8: October 2022, https://www.sciencedirect.com/science/article/pii/S1040619022001130.

Grid edge services affect individual customers; therefore, the value of these services tend to be based on the benefits provided specifically to the customer. Energy, for example, is valued based on the energy the customer does not have to pay for because their DER provides them with energy. Often this is presented to a customer as a lower bill.[123]

For customers, resilience services can be valued by accounting for the capital and operational cost benefits of avoided interruptions and outages for an individual customer. This can be captured through customer "willingness to pay" surveys and through estimating the costs of outages for a customer. Lawrence Berkeley National Laboratory (LBL) developed a report outlining the surveys that can capture customer interruption costs.[124] Avoided outages are also included as benefits in some BCAs for battery storage.[125]

How are ADER non-energy benefits valued?

Beyond providing the same grid services as traditional solutions, ADERs can provide additional non-energy benefits. These are, however, challenging to quantify for utilities and ISOs/RTOs. The comparative value placed on these benefits may vary from jurisdiction to jurisdiction based on public policy priorities.

GHG reductions

GHGs can include carbon dioxide, methane, nitrous oxide, and fluorinated gases. DERs emit far fewer tons of GHGs throughout their lifecycle than traditional generation or distribution and transmission grid upgrades.[126] Although there are many options for estimating the benefits of GHG reductions, two common methods are using the social cost of carbon or estimating the marginal abatement cost of the ADER.

The **SCC** is a monetization of the economic, social, and environmental impacts of emitting carbon and can be used to calculate the benefits of using ADERs instead of thermal generation. The SCC is based on research performed by the U.S. Environmental Protection Agency (EPA). The SCC has varied significantly over the years and is expected to continue to change as the EPA continues to perform new studies. However, the current value is $51 per metric ton of carbon dioxide.[127] This cost can be included in the BCA of ADERs in place of using numbers attributed to counterfactual traditional thermal generation.

The **marginal abatement cost method** requires identifying the GHG emission reduction options needed to reduce climate change as well as the normalized net levelized cost of all ADER solutions. The normalized net levelized cost is the levelized benefits minus levelized cost of the ADER solution, divided by the amount of energy saved or generated by the ADER. The ADER levelized costs are then ranked based on their net levelized cost to create a marginal abatement cost graph, wherein the vertical axis presents the net levelized cost of each DER and the horizontal axis presents the amount of potential GHG savings from each DER. The

123 BTM solar's main benefit is its ability to generate electricity for the customer. For an example, please see Xcel Energy, "On-Site Renewable Energy: Generate Your Own Electricity and Get Credit for Producing More Than Your Monthly Usage," accessed April 25, 2024, https://co.my.xcelenergy.com/s/renewable/solar-rewards.

124 Michale Sullivan, Myles T. Collins, Josh Schellenberg, and Peter H. Larsen, *Estimating Power System Interruption Costs, Nexant Inc and LBL, section 3.1,* https://eta-publications.lbl.gov/sites/default/files/interruption_cost_estimate_guidebook_final2_9july2018.pdf.

125 For example, the Massachusetts Connected Solutions Program includes a VoLL in their cost-effectiveness assessment. For the Massachusetts value see, Todd Olinsky-Paul, *Energy Storage: The New Efficiency – How States Can Use Energy Efficiency Funds to Support Battery Storage and Flatten Costly Demand Peaks, Clean Energy Group, April 2019,* https://www.cleanegroup.org/wp-content/uploads/Energy-Storage-The-New-Efficiency.pdf.

126 Lifecycle Analysis is a tool used to calculate GHG emissions across a products total lifespan, from design, commissioning, use, and decommissioning. DERs will contribute some atmospheric GHG over their lifecycle; we therefore do not equate DERs to zero GHGs.

127 The SCC has varied from $43/tCO_2$ globally under the Obama administration, $3–5/tCO2 for U.S. emissions under the Trump administration, and is currently $51/tCO2 under the Biden administration. The EPA proposed a value of $190/tCO2 in 2022; U.S. EPA, *EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, November 2023, https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf.

marginal abatement cost is the point where the marginal abatement cost options intersect with the GHG abatement target.[128]

Pollutant emission reductions

Energy production can result in pollutants that impact public health. Primary pollutant emissions from energy resources include nitrogen oxides, sulfur dioxide, particulate matter, ozone, carbon monoxide, volatile organic compounds, mercury, and lead.[129] DERs, such as distributed solar, can reduce emissions by reducing the production and consumption of fossil fuels that emit these pollutants. The general method to calculate the public benefits associated with fewer pollutant emissions is to quantify emission impacts based on the energy saved or generated by ADERs, calculating the change in air quality associated with the change in emissions, and quantifying the public health impacts associated with the changes in air quality. The public health impacts associated with the reduced emissions are then assigned a dollar value.[130] The EPA also has a publicly available Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool, which estimates the value of health impacts associated with changes in air pollution emissions.[131]

Social equity

Grid operators and utilities may place value on the ability of ADER grid services to support states' social equity goals. For example, PUCs may use their role to require or encourage grid operators and utilities to actively procure ADER grid services from underrepresented and historically underserved communities, providing both financial benefits and improvements to air quality due to DER adoption.[132]

Industry development explainer: Seeding Future ADER Grid Service Provisions

Policymakers may consider whether there is value in effectively "over-paying" for ADER grid services today, in the expectation that financially stimulating ADER grid service provisions will lead to benefits in the future.

Stimulating ADER grid service provisions today could lead to higher DER availability and associated downward pressure on costs in the future. This is the "market transformation" argument for ADER grid services.[133]

ADERs could be a valued grid resource to flexibly support the reliability of the future electric grid, if suitable ADER grid service options are developed and supported today. It could also mitigate potential challenges associated with unmanaged DERs, such as voltage management issues as DER penetration increases.

"Market transformation" grid services from ADERs may risk challenge from traditional solution providers, who may find themselves less competitive due not to current BCAs but based on the calculation of future benefits.

continued

128 Tim Woolf et al., *Methods, Tools and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis, March 2022, section 7.1,* https://www.nationalenergyscreeningproject.org/wp-content/uploads/2022/03/NSPM_Methods-Tools-Resources.pdf.

129 This list does not include the GHG emissions from energy resources. Those are noted in the "GHG Reduction" sections.

130 U.S. EPA, *Public Health Benefits per kWh of Energy Efficiency and Renewable Energy in the United States: A Technical Report, 2021,* https://www.epa.gov/statelocalenergy/public-health-benefits-kwh-energy-efficiency-and-renewable-energy-united-states.

131 U.S. EPA, "COBRA."

132 New York's Climate Leadership and Protection Act (CLPA, 2019) requires that state agencies, such as the PUC, direct investment in clean energy programs toward disadvantaged communities, such that these communities receive a minimum of 35% of benefits (with a goal of 40%); New York State Department of Public Service, *CLCPA-Disadvantaged Communities Investment and Benefits Reporting Guidance*, 2023, https://dps.ny.gov/system/files/documents/2023/10/disadvantaged-communities-guidance.pdf. This requirement may mean that ADER grid services from these communities are given preferential treatments in the merit order of dispatch given the value placed on meeting social equity objectives.

133 Market transformation refers to investing in technology today to make it easier or less costly to invest in the technology tomorrow.

Under current practices in the United States, "market transformation" is not widely considered, and in most instances, efforts are first made to "level the playing field" so that ADERs and traditional solutions can participate and compete on equal terms.[134] However, this does not mean "market transformation" might not be considered in the future.[135]

Focus area: Why are some grid services worth more than others? Are we not just talking about units of energy?

Units of energy providing grid services are valued according to their location and timing and the nature of the grid service requirement.[136] The energy or capacity provided will be more or less valuable based on the utility and/or ISO/RTO requirements, as well as policy goals in the state or jurisdiction.

ADER grid service providers, such as aggregators and their customers, will have varying risk profiles and preferences, which will influence how they respond to varying price signals for different grid services.

Locational Value

The value of a grid service is contingent on the location of the requirement. The nature of costs in meeting a requirement at a given location vary by the availability of solutions, local distribution and transmission loading capability, land use costs, remoteness or distance to the location, frequency of grid service issues in the location, and operational costs of providing grid services at that location.[137] These contextual factors can be cumulative or counteractive and need to be accounted for in all valuation of grid services, whether from ADERs or more traditional resources. Use cases for assessing locational value include NWS procurement, tariff structures, and program design.[138]

Temporal Value

The value of a grid service is also impacted by the time of day, ramp time, and duration for which it is required. These factors will determine eligibility of different solutions for grid services, with a premium placed on grid services available during peak load periods, short ramp times, and for extended durations. For example, evaluators are considering the time-sensitive value of energy efficiency, assessing the value based on when a measure provides energy savings during the year.[139]

Are there existing tools or examples I can use to estimate the value of grid services from ADERs?

Many jurisdictions have published avoided costs for purposes of assessing the cost-effectiveness of demand-side management (DSM) programs. Some states, such as Massachusetts, include an extensive list of costs and benefits, not all of which are applicable to ADERs. We have selected some examples of public tools that can be used to value ADERs and handbooks that provide sample grid service and non-energy benefit calculations for ADERs. **Table 13** is a summary of these resources and the types of grid services they evaluate.

134 Solar Energy Industries Association (SEIA), "Comment on the Need for Level Playing Fields in PJM Markets to Enable 'Full-Stack Flexibility'," 2022; Jeremiah Miller, *Principle-Based Planning Studies & Full Stack Flexibility,* SEIA, March 2022, https://www.pjm.com/-/media/committees-groups/committees/pc/2022/20220329-special/20220329-item-06-seia-long-termtrans-planning-reform-presentation.ashx.

135 "Market transformation" has been an important consideration for energy efficiency since the 1990s. For example, the design and implementation of the Energy Star program has used the tenets of market transformation to reduce market barriers for energy efficiency adoption. United States Government, "Market Transformation," accessed April 25, 2024, https://www.energystar.gov/partner-resources/utilities-eeps/prog-design-res/market-trans.

136 Determining location-specific values requires a robust distribution system planning process.

137 Natalie Mims Frick et al., *Locational Value of Distributed Energy Resources,* LBL, 2021, https://eta-publications.lbl.gov/sites/default/files/lbnl_locational_value_der_2021_02_08.pdf.

138 Ibid.

139 Natalie Mims Frick and Lisa C. Schwartz, *Time Sensitive Value of Efficiency: Use Cases in Electricity Sector Planning and Programs,* LBL, 2019, https://emp.lbl.gov/publications/time-sensitive-value-efficiency-use.

Table 13: Summary of Existing Tools and Examples of Grid Service Valuation

Tool/Methodology Handbook	Brief Description	Energy Benefits Evaluated				Non-Energy Benefits Evaluated	
		Bulk Power Energy & Capacity Grid Services	Bulk Power Essential Reliability Services	Distribution Grid Services	Grid Edge Services	GHGs	Pollutant Emissions or Social Equity
National Standard Practice Manual (NSPM) for Benefit-Cost Analysis of Distributed Energy Resources[140]	Summarizes the BCA principles for DERs and summarizes cost-effectiveness considerations for multiple DERs.	✔	✔	✔		✔	✔
New England Avoided Energy Supply Costs Report[141]	Forecast of estimated annual electric and gas costs that would be avoided due to reductions in gas and electricity use and methods for estimating avoided costs.	✔	✔	✔		✔	
California Avoided Cost Calculator[142]	Estimates '8,760' benefits by year for a DER in California.	✔	✔			✔	
New York Solar Value Stack Calculator[143]	Calculator used to estimate the value of distributed solar in NY.	✔				✔	
Time-Sensitive Value Calculator[144]	Calculator estimates the hourly value of ADERs.	✔	✔			✔	
LBL Interruption Cost Estimator[145]	Estimates the value of lost load by customer type based on region and current SAIDIs and CAIDIs.			✔	✔		
Central Hudson Benefit Cost Handbook[146]	Detailed methodology used by Central Hudson Utility in New York for estimating all of the costs and benefits used to estimate cost-effectiveness of DERs.	✔	✔	✔		✔	

140 National Energy Screening Project, *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, 2020, https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

141 Synapse Energy Economics, "Avoided Energy Supply Costs in New England (AESC)," accessed April 25, 2024, https://www.synapse-energy.com/avoided-energy-supply-costs-new-england-aesc.

142 E3, "Avoided Cost Calculator for Distributed Energy Resources (DER)," accessed April 25, 2024, https://www.ethree.com/public_proceedings/energy-efficiency-calculator/.

143 New York State, "Solar Value Stack Calculator," accessed April 25, 2024, https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Solar-Value-Stack-Calculator.

144 LBL, "Time Sensitive Value Calculator," last updated February 2022, https://emp.lbl.gov/publications/time-sensitive-value-calculator.

145 LBL, "ICE Calculator," Resource Innovations, accessed April 25, 2024, https://icecalculator.com/home.

146 Central Hudson, *Central Hudson Distributed System Implementation Plan*, 2023, p. 587, https://jointutilitiesofny.org/sites/default/files/Central%20Hudson%202023%20DSIP.pdf.

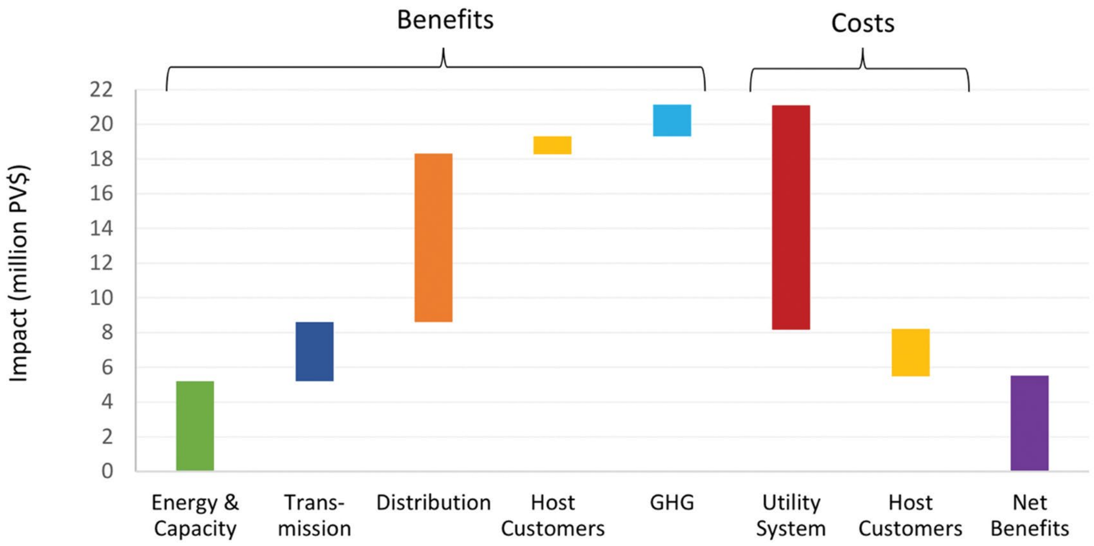
Tool/Methodology Handbook	Brief Description	Energy Benefits Evaluated				Non-Energy Benefits Evaluated	
		Bulk Power Energy & Capacity Grid Services	Bulk Power Essential Reliability Services	Distribution Grid Services	Grid Edge Services	GHGs	Pollutant Emissions or Social Equity
EPA Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool[147]	Helps state and local governments explore how clean energy policies and programs affect human health and the value of the health benefits that result from these programs.						✔
Distributional Equity Analysis Guidance[148]	Provides guidance on how utility investments in DERs impact specific populations and communities.						✔*

*The Distribution Equity Analysis Guidance report has not been published at the time this document was published, so the values in the report are subject to change. The document is expected to be published in 2024.

How are all these values combined to inform cost-effectiveness tests?

Once all potential values are estimated, policymakers can combine all the benefits ADERs provide and assess the total value of an ADER. The value can then be employed through the compensation mechanisms described in the next section: prices or programs. When implementing a program, policymakers need to determine the total value of the ADER program and compare it to the potential costs of implementing the program, otherwise known as a cost-effectiveness test. Net benefits are calculated by subtracting all ADER costs from the total ADER benefits. **Figure 9** is an example of how the benefits and costs can be combined to calculate the net benefits of a hypothetical resource.

Figure 9: Example of Cost and Benefit Stacking for a Potential Resource from the NSPM



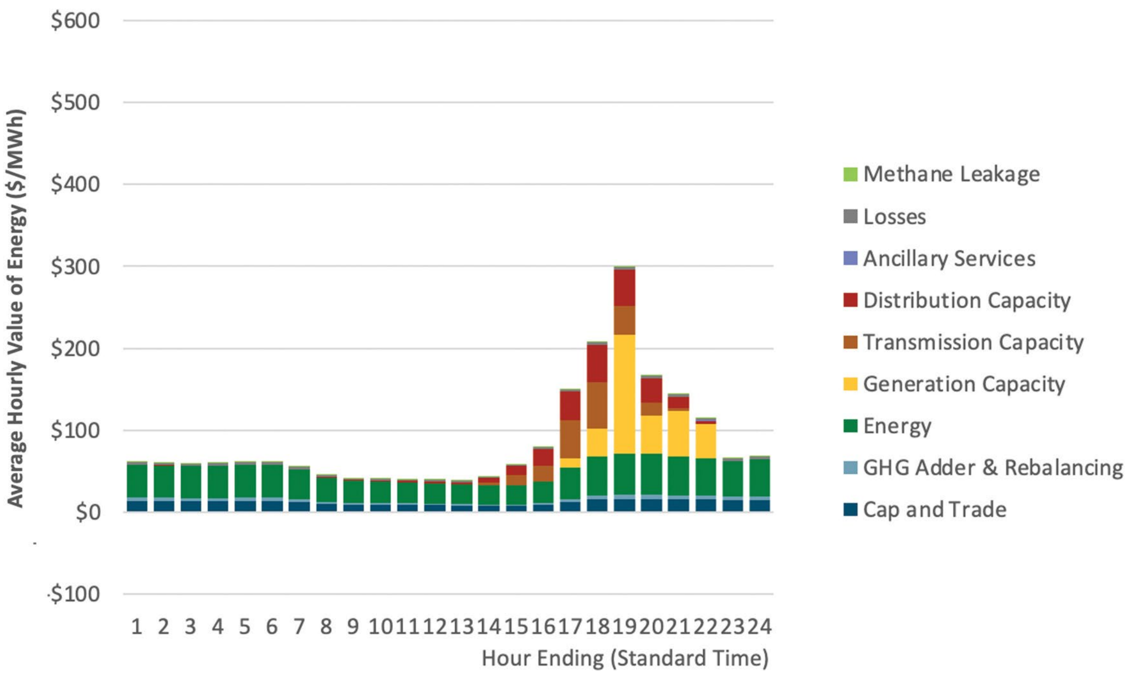
147 U.S. EPA, "COBRA."

148 Tim Woolf et al., *Distributional Equity Analysis for Energy Efficiency and Other Distributed Energy Resources: A Practical Guide*, LBL, 2024, https://emp.lbl.gov/publications/distributional-equity-analysis.

Figure 10 is an example of how the Avoided Cost Calculator (used in California for energy efficiency) stacks different grid service values based on the hour of the day.

Figure 10: Sample Avoided Cost Calculator Value Stack by Hour of Day[149]

(adapted from Energy + Environmental Economics's (E3) Avoided Cost Calculator)



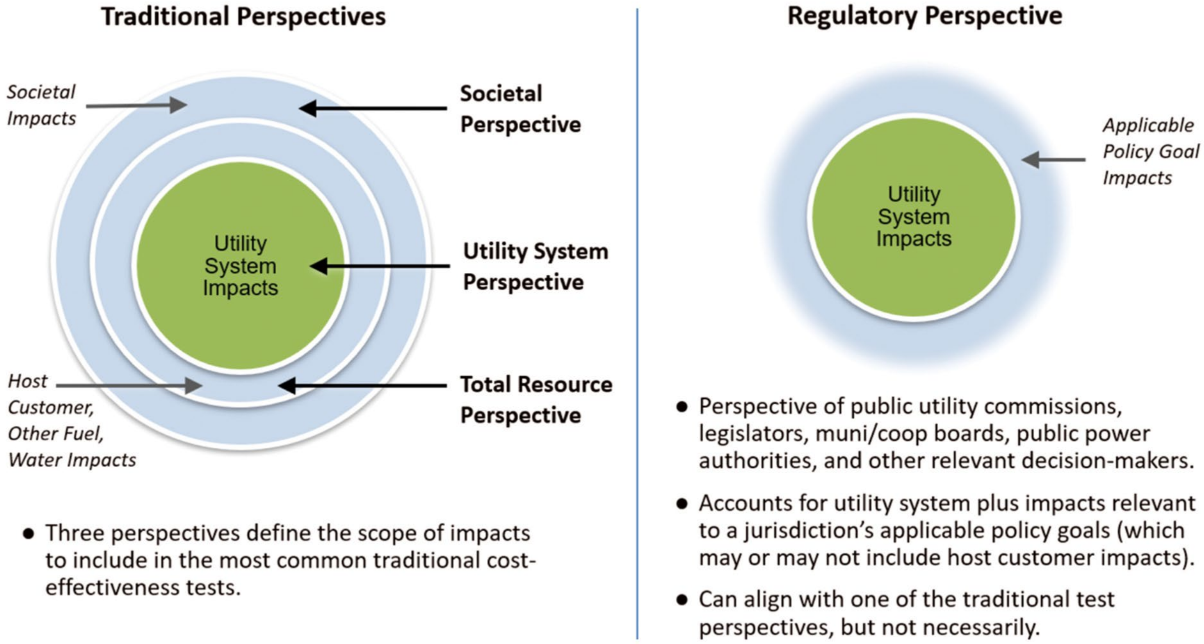
Cost-effectiveness tests can be used both for programs implemented by a utility (or an aggregator) and for assessing bids in a competitive procurement process to determine which ADER solution has the highest overall value. There are five traditional cost-effectiveness tests traditionally used to evaluate DERs, established in the 2001 California Standard Practice Manual.[150] Each test explicitly includes or excludes different values based on the question that the cost-effectiveness test is trying to answer. As the DER landscape evolves, more recent cost-effectiveness resources, such as the National Standard Practice Manual (NSPM) for DER BCA, note the limitations of these traditional tests. To realize the full potential of DERs, states can design their own benefit-cost test (also called a Jurisdiction-Specific Test) to ensure the state's policy objectives are taken into account when assessing cost-effectiveness. This is also known as the "regulatory perspective." **Figure 11** compares the traditional perspectives with the regulatory perspective proposed by NSPM.[151]

149 E3, "Avoided Cost Calculator for Distributed Energy Resources (DER)," accessed April 25, 2024, https://www.ethree.com/public_proceedings/energy-efficiency-calculator/.

150 CPUC, *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, 2001*, https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy_-_electricity_and_natural_gas/cpuc-standard-practice-manual.pdf.

151 The NSPM contains detailed principles and guidelines for establishing cost-effectiveness analysis frameworks. National Energy Screening Project, *National Standard Practice Manual (NSPM) for Benefit-Cost Analysis of Distributed Energy Resources, 2020*, https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

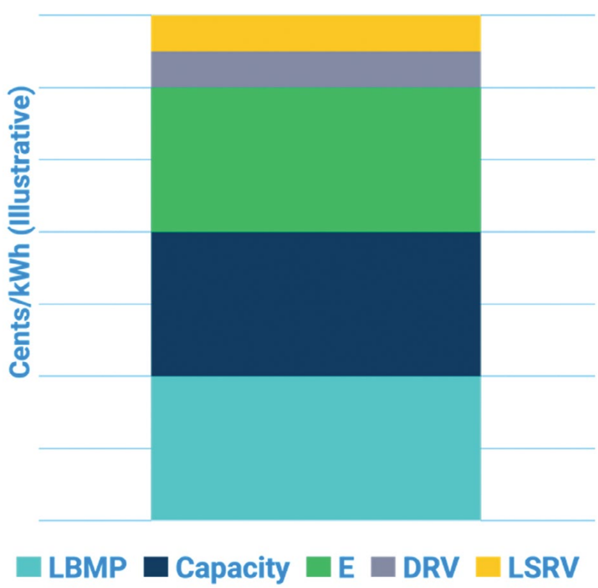
Figure 11: Comparison of Regulatory Perspective Cost-Effective Test with Traditional Test Perspectives



How are grid service values combined to inform pricing?

As noted above, once the value of ADERs have been estimated, it can then be employed through either prices or programs to compensate customers for their grid services. When compensating customers for ADER grid services through prices, the value of the grid service is either translated into a rate or other price signal or is determined by the market. The pricing design—how the value is allocated—will vary depending on the state and market requirements, as well as the pricing structure used. For example, New York has developed a wholesale value stack for DER customers that opt in and sell energy and capacity in the wholesale market directly to the NYISO. See **Figure 12** for an illustrative example.

Figure 12: Illustrative New York Wholesale Value Stack[152]



152 Sandra Sweet, *New York State: Value of Distributed Energy Resources*, 2023, https://pubs.naruc.org/pub/83B3845A-BC6B-E175-10CC-35A38278310B.

ADER Compensation

This section discusses compensation mechanisms for ADER grid services. Compensation is how customers who provide ADER grid services receive money in exchange for their services. It also applies to how third-party aggregators or utilities who implement ADER programs are compensated. Compensation ensures that there is a mechanism in place to pay customers for the grid services that they provide and is instrumental in shaping ADER behavior and encouraging the growth of ADERs. Compensation is typically based on the values determined in the "ADER Valuation" section of this report.

Overview of ADER Compensation

The two key mechanisms for ADER compensation are **prices** and **programs**, which are described in **Table 14**. Prices are either electricity price signals sent to ADERs through customer rates or tariffs, or prices from the market that ADERs can participate in or respond to. Programs allow ADERs to participate and respond to events in exchange for a financial incentive. Programs can also participate in a market or can be dispatched by the implementer or grid operator in another manner.

Table 14: Compensation Mechanisms for ADER Grid Services

	Prices	Programs[153]
Compensation method	DER owners' electricity rates or export tariffs (when applicable) include time-varying components that provide them (or their utility or aggregator) opportunities for cost reductions or compensation based on ADER dispatch for the relevant grid service, including energy, demand, and ancillary services.	DER owners obtain funding, usually from a regulated utility, in exchange for adopting a DER and/or enrolling one in a program, making the device(s) available to dispatch in response to a range of ADER grid services during particular "events." The funding may be through an up-front incentive, or a payment on an ongoing basis.
Simple example	Time-of-use tariffs	Smart thermostat programs
Description	Price signals are sent to customers in the form of time-varying or demand-based electricity rates or export tariffs. Responses to price signals may be through manual control or automation. DER response may be at the customer level, or through an aggregation operated by a utility or a third party, responding to prices. Price signals can incorporate a number of required grid services, including energy, capacity, and transmission. Price signals can also be locational to reflect needs for specific grid services in specific locations on the electric grid. In programs, payments are given to incentivize customers to make DER capacity available for dispatch, either through adopting a DER or through enrolling a DER they already own in a program.	In programs, payments are given to incentivize customers to make DER capacity available for dispatch, either through adopting a DER or through enrolling a DER they already own in a program. Events are triggered by specific grid or economic conditions, meaning the utility or grid operator must seek a change in demand or generation patterns. Events may be scheduled in advance, for example discharging batteries between 6 to 8 p.m. on weekdays; or they may be scheduled with shorter lead times, for example scheduled a day in advance based on weather or scarcity forecasts. Events may be locationally specific to reflect the needs for specific grid services in specific locations on the electric grid.

153 Programs can be organized by a utility or a third party. They can also operate based on pre-determined grid conditions or they can be bid directly into the electricity market as a resource. Program implementation options are explored in more detail in the "Programs" section.

	Prices	Programs
Compensation arrangements	Arrangements for responding to prices may include: • Wholesale market participation (through an aggregator) • Export rates • Time-of-use tariffs • Critical peak pricing • Real-time or "dynamic" pricing • Monthly subscriptions	Arrangements for participating in programs may include: • Pay-for-performance or performance payments (measurements can be based on kW dispatched, grid service met, or flat rate per dispatch) • Incentive for device in exchange for program participation • Direct payment in exchange for program participation • Subsidy for interconnection in exchange for program participation

Foundational Questions

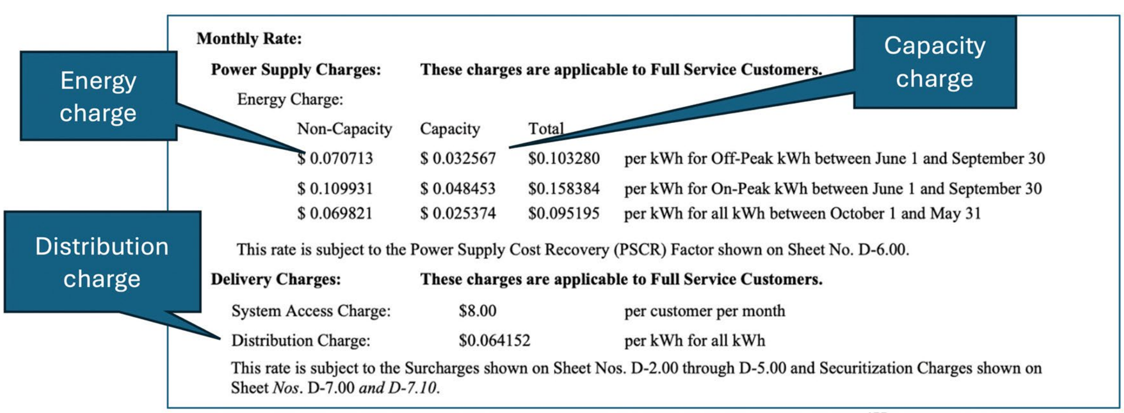
What are "prices" and how can they be used to compensate ADERs?

Price response can be to **market prices** or **customer retail tariffs**. With market prices, ADERs can respond directly to prices provided by the market. For example, this can include programming ADERs to respond to real-time energy prices. ADERs can also bid directly into energy, capacity, or ancillary service markets so they are dispatched when the resource is most cost-effective.

ADER compensation via "customer tariffs" means price signals are sent to customers that more closely reflect the time-varying current and future costs of supplying and delivering energy.[154] Some customers, or their utilities or aggregators, will be billed or otherwise be able to gain value out of prices for energy, capacity, and grid infrastructure relief, including transmission, ancillary services, and distribution. The costs of these services change based on when these services are consumed/provided. Customers or aggregators can provide grid services through ADERs by shifting electricity generation or consumption patterns in response to price signals.

Customer rates typically reflect the utilities' cost of providing different grid services to customers. **Figure 13** and **Figure 14** provide an example of how capacity, energy, and distribution costs and infrastructure upgrades are included in a residential rate. How these charges are included in rates will vary depending on the state and the customer's rate class.

Figure 13: Example of a Residential Tariff Breakout[155]



Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service Customers.**

Energy Charge:

Non-Capacity	Capacity	Total	
$ 0.070713	$ 0.032567	$0.103280	per kWh for Off-Peak kWh between June 1 and September 30
$ 0.109931	$ 0.048453	$0.158384	per kWh for On-Peak kWh between June 1 and September 30
$ 0.069821	$ 0.025374	$0.095195	per kWh for all kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: **These charges are applicable to Full Service Customers.**

System Access Charge: $8.00 per customer per month

Distribution Charge: $0.064152 per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet *Nos.* D-7.00 *and D-7.10.*

154 While thoughtfully designed export rates for standalone DER systems (e.g., NEM and NEM successors) are important mechanisms to encourage DER adoption and compensate energy injected into the grid, this report does not discuss these at length given the focus on dispatchable and controllable ADERs.

155 Consumers Energy Company, *Rate Book for Electric Service, 2019*, https://www.consumersenergy.com/-/media/CE/Documents/rates/electric-rate-book.pdf.

Figure 14: Example of the Portion of a Rate Dedicated to Infrastructure Relief from Oncor Energy[156]

Infrastructure relief

Transmission Cost Recovery Factor (TCRF)

	Residential Service	Secondary Service			Primary Service				Transmission Service
		≤ 10 kW	>10 kW		≤ 10 kW	>10 kW Distribution Line		Substation	
Effective Date	($/kWh)	($/kWh)	($/NCP kW)	($/4CP kW)	($/kWh)	($/NCP kW)	($/4CP kW)	($/4CP kW)	($/4CP kW)
March. 1, 2024	0.016291	0.014368	4.369967	4.874899	0.009247	5.498543	4.396273	2.973098	4.960216

Rate design influences how closely rates truly reflect the utilities' cost of providing grid services. A "flat" rate with a single value will not reflect periods when it is more or less costly for the utility to provide energy. By creating a **time-varying rate**, which has higher prices when the energy supply or grid capacity is constrained, the price faced by the customer is more closely tied to the cost of providing electricity.[157]

For example, one component of customer rates is energy, which is typically a $/kWh value. The energy component of the rate is meant to reflect the price at which a utility purchases energy or the marginal cost of the next "unit" of energy. However, customers often pay a flat rate for energy, so they are not exposed to temporal cost variations. Some states have moved toward methodologies for customer rates that more accurately reflect the nature of changing prices. An example is the rate in Figure 13, where there are three separate energy charges depending on the time of year and the time of day.

Capacity charges can similarly vary in time. In some jurisdictions, customers pay a flat rate at all times, and capacity is typically seen as a "capacity adder" charge. For large customers, this can also occur in the form of a "demand charge," which is either based on a customer's overall maximum demand or the customer's maximum demand during a specified peak window of time (called "coincident demand" because it aligns with the system peak). In time-varying rates, the utility can allocate the capacity value to hours when capacity constraints are likely—see the rate example in Figure 13, where the capacity rate is higher during the summer peak window. Demand charges can be limited to demand during the system peak window, better reflecting capacity constraints of the grid.

Grid infrastructure relief can be reflected in a price in a distribution or transmission rate (the rates that retail customers use to pay for the Texas ERCOT grid are shown above in Figure 14) or in another charge, such as for system access. To avoid or defer electric grid upgrades, the utility can vary these rates to be associated with the cause of additional capital investments, such as peak demand. More nuanced timing and locational elements can also be added to such rates.[158]

Essential reliability services, including ancillary services, typically are not separately stated in residential customer price signals and are instead bundled together as part of supply or transmission service, although larger customer classes may pay unbundled charges associated with these services.

156 Oncor Electric Delivery Company LLC, *Tariff for Retail Delivery Service*, 2023, p. 97, https://www.oncor.com/content/dam/oncorwww/documents/about-us/regulatory/tariff-and-rate-schedules/Tariff%20for%20Retail%20Delivery%20Service.pdf.coredownload.pdf.

157 Location-varying rates may also be considered in the future, but at present, locational signals are generally managed through programs and some export tariffs rather than prices. LBL expands on the location and value of DERs in Natalie Mims Frick et al., *Locational Value of Distributed Energy Resources*, LBL, February 2021, https://emp.lbl.gov/publications/locational-value-distributed-energy.

158 New York's value of DER rates, for example, compensate DER projects based on where and when they provide electricity to the grid. Joint Utilities of New York, "Value of Distributed Energy Resources," accessed April 25, 2024, https://jointutilitiesofny.org/distributed-generation/VDER.

While time-varying pricing can be applied anywhere, ADERs can help enable customers to shift their load more effectively in response to time-varying prices. Pricing can provide a clear incentive for customers to benefit from shifting EV charging, reducing their load during peak demand periods, and optimizing when their battery and solar systems export to the grid.

What are examples of price structures that can compensate ADERs for grid services?

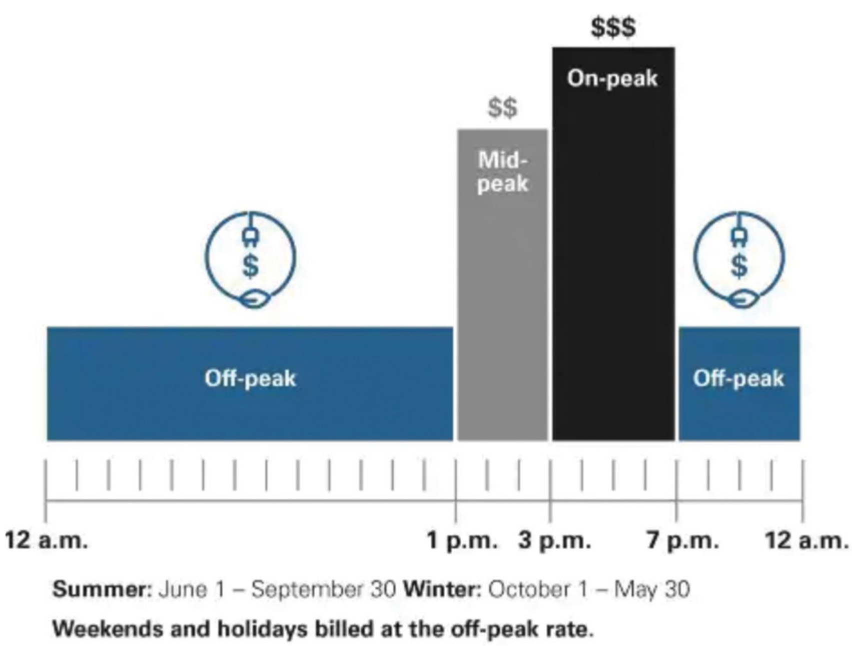
Market Prices

ADERs can directly participate in wholesale markets where they are dispatched by market operators. If an aggregator participates directly in the market, the aggregator's revenue is determined by how often the resources are dispatched in the wholesale market and the clearing price at which they are dispatched. The aggregator can determine how to compensate its participants and can use program compensation mechanisms (described in the next section) if appropriate. Aggregators can participate in the wholesale capacity, energy, or ancillary service markets depending on whether market rules allow ADER participation, the availability of grid services required, and the availability of ADERs able to provide the grid services. Rather than participating directly in the market, ADERs can also be programmed to respond to market prices. For example, Octopus Energy offers residential customers the option to optimize their batteries to discharge when real-time market prices are highest.[159] The ADER responds to market prices without exposing the participant to the full risk of a real-time pricing rate.

Time-of-Use Rates

Time-of-Use (TOU) rates offer different electricity prices depending on the time of day and the time of year. **Figure 15** shows an example of TOU rates; prices are higher during "on-peak" hours and lower during "off-peak" hours. Depending on the rate, prices can vary in the summer and winter, and there can be additional tiers such as "super off-peak" or "mid-peak," each with their own price. Figure 15 is an example of how prices can differ throughout the day on a TOU rate.[160]

Figure 15: Xcel Energy's TOU Rate



159 Octopus Energy, "Empower Your Home Battery with Octo GridBoost," accessed April 25, 2024, https://octopusenergy.com/octo-gridboost.

160 Xcel Energy's TOU rate, is described in Xcel Energy, "Residential Rates: Time-of-Use," accessed April 25, 2024, https://co.my.xcelenergy.com/s/billing-payment/residential-rates/time-of-use-pricing.

On a TOU rate, customers can save money on their bills by reducing their usage each day during the "on-peak" window when prices are higher.[161] For a TOU rate, the peak window and prices are both determined ahead of time and tend to be relatively static (e.g., 4 to 9 p.m. when people come home from work). Therefore, customers will know well ahead of time when they should shift their load every day. Tariffs that target specific technologies, such as EV rates, can help shift load for specific DERs. Additionally, technology-enabled daily shifting, such as daily thermostat set point changes, daily battery discharge, or daily water heater temperature changes, can all provide predictable daily shifting impacts.

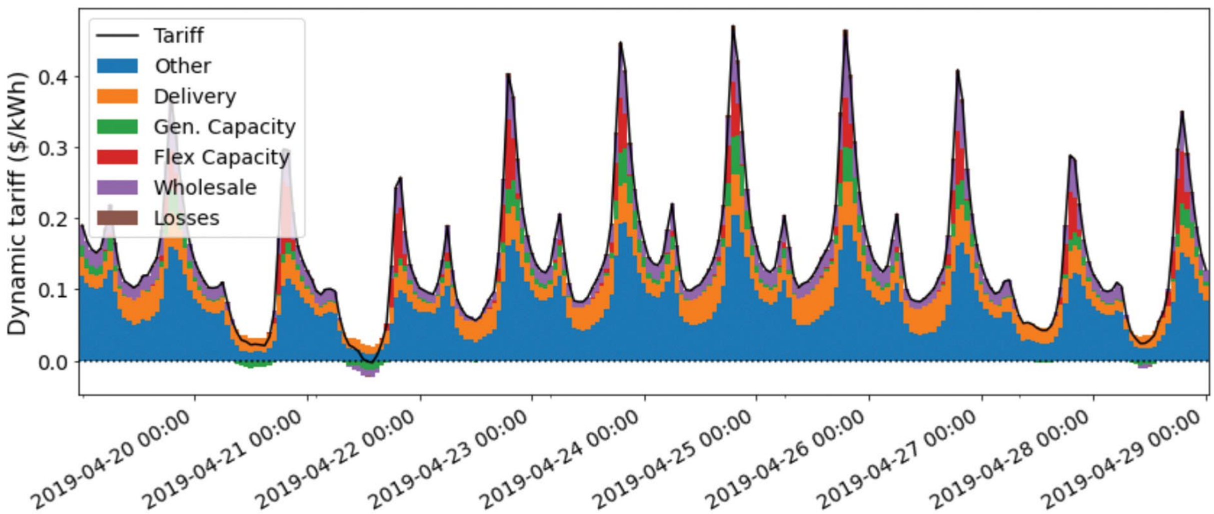
Critical Peak Pricing

Critical peak pricing rates may be additions to either flat or TOU rates. For the majority of the year, there is either a single flat volumetric price or "on-peak" and "off-peak" TOU prices depending on the time of day. However, there are also select periods throughout the year where rates are significantly higher, known as "critical peak events." For example, in California the critical peak pricing rate allows the utility to call up to 15 critical peak events during the year between 4 and 9 p.m.[162] During those events, customers can save money on their bills by reducing (or further reducing) their usage during the time when the price is much higher than even an on-peak TOU rate. As an alternative to high critical peak prices, customers can receive a bill credit for reducing their load during critical peak periods. This is sometimes referred to as a "peak time rebate." Again, customers are able to save money if they are able to shift their load away from the high price periods. ADERs can provide technology-enabled shifting during critical peak price periods, such as thermostat set point changes, battery discharge, or water heater temperature changes.

Real-Time Pricing

A real-time pricing rate, unlike other rates, is based on exposing customers to the actual hourly market price for energy. Therefore, the price differs each hour and each day. In real-time pricing rates today, customers receive hourly pricing alerts informing them when prices will be high so they can shift their usage during high price hours to save money on their bills.[163] Real-time pricing allows customers to face actual market prices and be incentivized to reduce their usage when the grid is most stressed.

Figure 16: Example Real-Time Pricing Tariff over a 10-Day Period, LBL



161 TOU tariffs can also be targeted toward customers who own a specific technology. For example, there are EV rates limited to customers who currently own an EV. The rate is often set up to have very low prices overnight to encourage customers on the rate to charge their vehicle overnight rather than during the day.

162 Southern California Edison's explanation of its critical peak pricing program; Southern California Edison, "Critical Peak Pricing (CPP) for Business," accessed April 25, 2024, https://www.sce.com/business/rates/cpp/cpp-guide-faq.

163 ComEd's explanation of its hourly pricing program; Commonwealth Edison Company, "Frequently Asked Questions," accessed April 25, 2024, https://hourlypricing.comed.com/faqs/.

Figure 16 shows an example of real-time pricing tariff over a 10-day period, as modeled in a LBL study on the impacts of dynamic rates on customer bills.[164]

Customers on a real-time pricing rate are able to maximize their savings if they are able to dynamically respond to high prices. Instead of a static load shift in response to a dynamic rate, such as changing a thermostat set point every day at the same time, DER technologies such as battery storage can be programmed to respond dynamically to real-time pricing rates, charging when prices are low, and discharging when prices are high. However, these technologies are still being developed and are not yet widely implemented.[165]

Industry developments explainer: Monthly Subscriptions

Like cell phone tariffs, monthly subscription rates, also known as energy-as-a-service, allow customers to pay a flat rate each month based on an energy consumption plan they choose ahead of time. Consumption plans are typically based on a customer's prior usage, and they receive notifications throughout the month to help them manage their usage for their plan. Monthly subscriptions help grid operators and utilities manage grid requirements by providing anticipated customer usage ahead of time, improving the accuracy of grid services forecasts. The costs of monthly subscriptions also reflect the strain customers are expected to place on the electric grid. While monthly subscriptions plans can be simple and operate on a single fixed charge value, there are also more sophisticated subscription rates, often accompanied by third-party implementation or enabling technologies that can encourage customers to shift their loads. However, these types of rates are still being developed.[166] **Figure 17** offers an example of what a tiered rate offering could look like where there is a flat price and different demand management options.

Figure 17: Mock-up of Subscription Rate Offering That Includes Load Control[167]

	Unlimited Savings	Unlimited Choice	Unlimited Premium + EV
Fixed monthly price based on household profile usage (Your average current bill is $115/month)	$115/month for 36 months	$125/month for 36 months	$145/month for 36 months
30% Clean Energy with energy portal app	✓	✓	✓
100% Clean Energy	✗	✗	✓
Free Smart Thermostat	✓	✓	✓
Access to free or discounted energy efficiency upgrades	✓	✓	✓
Unlimited EV charging at home and in community	✗	✗	✓
Maximum number of control days	30	15	7
Maximum number of overrides per year	3	5	7

164 Page 16 of the study, Brian F. Gerke et al., *Potential Bill Impacts of Dynamic Electricity Pricing on California Utility Customers, LBL, 2022*, https://escholarship.org/uc/item/2wj199mq.

165 Some pilots, such as Pacific Gas and Electric Company's 2023 battery storage pilot, have tested the technical capability of battery storage to respond to dynamic rates but noted that further iterations are needed. Pacific Gas and Electric Company, *DR Emerging Technology (DRET) BTM Residential Battery Load Management Study, 2023*, https://www.dret-ca.com/wp-content/uploads/2023/11/PGE-DRET-BTM-Residential-Battery-for-Load-Management-Study.pdf.

166 Lon Huber, "Primer: Subscription Pricing for Regulated and Competitive Energy Providers," *Guidehouse Insights*, October 12, 2018, https://guidehouseinsights.com/news-and-views/primer-subscription-pricing-for-regulated-and-competitive-energy-providers.

167 Graphic adapted from graphic developed by Guidehouse; National Rural Electric Cooperative Association, *Innovations in Pricing: Energy Service Subscription Pricing*, 2019, https://www.cooperative.com/programs-services/bts/Documents/Advisories/Advisory-Energy-Service-Subscription-Pricing-Feb-2019.pdf.

Industry developments explainer: Device-Specific Dynamic Rates

A relatively new concept is "prices to devices," where prices are directly sent to devices, unlike today, where prices are sent to the meter grid connection, thereby impacting all devices behind the connection point.

The concept of device-specific dynamic rates is to cause modulation of energy consumption and generation only within a specified device, for example, an EV. This means that other energy uses, such as essential and often less flexible loads such as cooking and lighting, are not impacted by the tariff. The concept also promises to enable tariffs to remain co-located with the device, rather than being tied to a geographical location. For example, this could enable smart EV charging tied to a customer's EV when visiting a friend's house.

Device-specific dynamic rates require "split metering" and "device-level metering" to be adopted to enable accurate metering, verification, billing, and settlement. It is currently being investigated in pilots.[168]

There are also pricing systems that are designed with flexible loads or devices in mind. For example, the California Energy Commission (CEC) Market Informed Demand Automation Server (MIDAS) database allows all ratepayers to access a single pricing system that provides their local hourly pricing information, including their dynamic rates. The CEC notes that "when connected to flexible loads (appliances or programs), it can increase efficiency and support decarbonization efforts."[169] The system takes steps to reduce tariff fragmentation and allows ratepayers to make comparisons between different technologies and their value propositions.

What are the different critiques of retail rates used to compensate ADERs?

Table 15 summarizes the frequently cited critiques of retail rates that can be used to compensate ADERs. For all time-varying rates, customers are only able to benefit from the rates if they are able to shift their load from high price to low price periods. Customers who are not able to shift their load tend to have higher bills when faced with time-varying rates compared to a flat rate. ADER automation helps customers respond to prices to minimize their bill impacts. Many of the drawbacks of time-varying rates are due to the fact that automation is not yet widespread, and responding consistently to changing rates can be difficult to navigate without automation.

Table 15: Frequently Cited Critiques of Retail Rates Used to Compensate DERs

	Proponents' Comments	Opponents' Comments and Considerations
TOU Tariffs	• Required advanced metering infrastructure (AMI) is well-deployed in the United States. • Clear and easier for customers to understand and plan accordingly.	• Not granular: peak time periods can be up to eight hours in duration, which does not align well with high price peak hours, which occur relatively seldomly. • Lagged response to changing electricity prices: changing the peak window for a TOU rate from 5 to 7 p.m. to 6 to 8 p.m., for example, would require changing the rate itself.
Critical Peak Pricing	• Allows for additional load shed on the relatively few days when energy and capacity prices are high. • Clear and easier for customers to understand and plan accordingly.	

168 Olivine, "Olivine Is Spearheading an Innovative Dynamic Pricing Demonstration Pilot in Partnership with Ecobee," last updated January 31, 2023, https://olivineinc.com/blog/olivine-is-spearheading-an-innovative-dynamic-pricing-demonstration-pilot-in-partnership-with-ecobee/.

169 CEC, "Market Informed Demand Automation Server (MIDAS)," accessed April 25, 2024, https://www.energy.ca.gov/proceedings/market-informed-demand-automation-server-midas.

	Proponents' Comments	Opponents' Comments and Considerations
Critical Peak Pricing	• Required AMI is well-deployed in the United States. • TOU, together with some price/rebate for extraordinary peak prices, could capture the vast majority of real-time price dynamics.[170]	• Without also providing automation, the rate relies significantly on manual customer interventions, which may suffer from dispatch fatigue for repeat events.[171]
Real-Time Pricing	• ADERs can be automated to respond rapidly to changing energy prices. • Reflects actual market conditions.	• Could expose customers to extreme prices.[172] • Less stable revenue for utility and more bill volatility for customers. • Difficult for customers to understand and plan their energy use around because it is constantly changing.
Monthly Subscriptions	• More bill stability for customers (especially beneficial for low-income households). • Utilities can supplement existing load forecasts with energy subscription data to increase accuracy. • Can encourage adoption of DSM technology.	• Relatively new concept with limited uptake. • Requirement for customers to manage their allowances may discourage enrollment. • No ability for grid operators and utilities to vary energy costs across the time of day. Needs to be combined with a program or include a device-specific dynamic rate component to shift usage.[173] • May reduce incentive for customers to invest in energy efficiency.
Device-Specific Dynamic Rates	• Potential for greater load shifting because of automation. • Ability for customers to vary specific loads with no interruption to less flexible loads.	• Limits ADERs to specific technologies. • High technology barriers (transmitting prices to devices and updating billing system).

How can ADERs be compensated through a program?

Programs typically require the program implementer (with the input of other relevant stakeholders) to determine and allocate monetary compensation to participants based on the value of the grid service(s) provided. Because participants are compensated using ratepayer money, consideration may need to be given to program design that does not adversely impact non-participants. For example, compensation can be based on a pre-determined percentage of the value to ensure that non-participants are also able to benefit from the program lowering overall costs (e.g., 70% of the total grid service value will be allocated to incentives for program participants, with the remainder of the benefits passed along to all ratepayers through lower rates).[174]

170 Tim Schittekatte et al., *Electricity Retail Rate Design in a Decarbonized Economy: An Analysis of Time-of-Use and Critical Peak Pricing*, National Bureau of Economic Research, 2022, https://www.nber.org/papers/w30560.

171 Center for Net Zero Powered by Octopus Energy, *Insights from the UK's Largest Consumer Energy Flexibility Trial: The Demand Flexibility Service and Octopus Energy Saving Sessions*, 2023, https://www.centrefornetzero.org/wp-content/uploads/2023/05/Centre-for-Net-Zero-Insights-from-the-UKs-largest-consumer-energy-flexibility-trial-May-2023.pdf.

172 During Winter Storm Elliot, the ERCOT real-time prices exceeded $9,000/MWh; ERCOT, *December 2022 ERCOT Cold Weather Operations Report (PUBLIC): Winter Storm Elliot Public Report*, 2022, https://www.ercot.com/files/docs/2023/03/27/December-2022-Cold-Weather-Operations-Public-Report.pdf.

173 Herman K. Trabish, "Momentum Grows for Piloting Netflix-Like Fixed Subscription Rates, But Not Everyone's on Board," *Utility Dive*, July 7, 2020, https://www.utilitydive.com/news/momentum-grows-for-piloting-netflix-like-fixed-subscription-rates-but-not/579486/.

174 Green Mountain Power's (GMP) Bring Your Own Device (BYOD) and Energy Storage System (ESS) programs allocated 80% of their capacity value to participant compensation to ensure that 20% of the program benefits were passed along to non-participants through lower rates from GMP's reduced capacity cost.

Program implementers determine the incentive structures for ADER programs, often with input from external stakeholders. There are four main incentive structures utilities can choose from. These structures are not mutually exclusive and are often combined—for example, availability payments are often combined with penalties. The incentive structures are:

1. **Up-front incentives (cash, device discounts).** Up-front incentives will most commonly be in return for program enrollment.[175] Up-front incentives can either be in the form of an equipment discount or a direct incentive to the customer. For example, an aggregator may run a customer smart thermostat demand response program. For equipment discounts, the customer may receive a free smart thermostat in exchange for allowing the aggregator to adjust their thermostat temperature if load reduction is needed. For a direct incentive to the customer, the customer may receive a bill credit in exchange for signing up a smart thermostat they already own to participate in the program and allowing the aggregator to adjust the thermostat temperature if load reduction is needed.[176] Up-front incentives do not need to be in the form of cash or a discount—for example, on-bill financing is another way to reduce the up-front cost of investment in ADERs. In on-bill financing, the utility incurs the cost of the upgrade, which is then repaid on the utility bill.[177]

2. **Availability payments.** Availability payments are payments to ensure an ADER is available at a given time to be called upon. The ADER participant will receive an annual, seasonal, or monthly $/MW or $/kW capacity payment in exchange for their participation.[178] To ensure a resource is dispatched when needed, availability payments can be accompanied by penalties for non-performance or activation payments for performance.

3. **Activation payments.** Activation payments are payments for the dispatch or response of an ADER to a grid service need or event, usually in $/MWh or $/MW, which is also referred to as "pay-for-performance."[179] Pay-for-performance can be for an average performance over a given period, for individual events, or for grid services provided. Pay-for-performance rewards customers based on how much they respond to dispatch signals, so customers have the option to respond more or less on a given day.

4. **Penalties for non-delivery.** Penalties can be levied for non-delivery of a grid service, acting as a deterrent for non-dispatch for program participants or third-party aggregators. If a program is participating in a market or is procured by the utility, the program implementer may face a penalty to recompense the grid operator or utility that may have to dispatch other resources at short notice to meet the grid service requirement. This penalty may be passed through to program participants as a part of the program incentive structure. The program implementer may decide on the penalty structure—for example, flat penalties per non-delivery or incremental penalties for repeated instances of non-delivery.[180] Some programs with penalties offer a limited number of "overrides" or "opt-outs" where customers are released from their obligation without penalty.

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175 Program enrollment can include remote dispatch of devices by the program implementer, programming a device to respond to a time-varying rate, programming a device to respond to a grid signal, or another form of providing a grid service.

176 The Massachusetts Connected Solutions program, for example, will provide a direct bill credit for any customers who elect to enroll a smart thermostat or their battery storage system in the program; "Connected Solutions Battery Program," National Grid, accessed April 25, 2024, https://www.nationalgridus.com/MA-Home/Connected-Solutions/BatteryProgram.

177 Office of State and Community Energy Programs, "On-Bill Financing and Repayment Programs," accessed April 25, 2024, https://www.energy.gov/scep/slsc/bill-financing-and-repayment-programs.

178 Large C&I demand response programs are common examples of capacity payments, such as the demand response program at Consumers Energy; Consumers Energy, "Commercial and Industrial Demand Response," accessed April 25, 2024, https://www.consumersenergy.com/business/products-and-services/demand-response.

179 For example, California's ELRP pays reductions of $2/kWh during demand response events; California Public Utilities Commission, "Emergency Load Reduction Program," accessed April 25, 2024, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/emergency-load-reduction-program.

180 The Base Interruptible Program in California, for example, will pay customers to reduce their load to a pre-determined kWh level, or "Firm Service Level" when called upon. Customers must pay a flat penalty of $6/kWh for every kWh that exceeds their agreed-upon firm service level. Pacific Gas and Electric Company, "Demand Response Programs for Business," accessed April 25, 2024, https://www.pge.com/en/save-energy-and-money/energy-saving-programs/demand-response-programs/business-programs.html#accordion-b2e15ef020-item-a5a743781f.

Industry developments explainer: Rate and Fee Discounts

Discounts are an alternative up-front incentive payment acting as a form of compensation for ADERs. Discounts can be applied to interconnection fees or customer rates in exchange for "flexible interconnection," or the ability to curtail or otherwise control DER generation or consumption without compensating the customer. Flexible interconnection discounts can be applied to both generation and demand DERs, and when multiple DERs are contracted in this way, they can effectively provide ADER grid services to utilities or grid operators.[181] At present, few states enable flexible interconnection discounts. However, there are many utilities with "interruptible customers," where a customer gets a discount on their rate, and in exchange, the utility has the option to interrupt the customer's service if needed. Interruptible customers tend to be very large and often have backup generation available to them in the event of service disruption.[182]

For rate and fee discounts to work, it is important to note that a discount may or may not be the same as the revenue a DER could expect to earn from providing grid services. Therefore, considerable attention should be paid to what the discount is and how it is applied if this type of program is implemented, how long the customer is obligated to provide the uncompensated grid service, and transparency on when and how discounts are applied and what services are provided from the DERs in return.

Table 16 summarizes the frequently cited critiques of different incentive structures.

Table 16: Frequently Cited Critiques of Different Incentive Structures

	Proponents' Comments	Opponents' Comments and Considerations
Up-front Incentives	• Simplest program design: the benefits are clear and transparent for customers. • Up-front incentives can be used to target ADER adoption for low- to moderate-income customers.	• Compensation may not include the full value of energy, capacity, transmission, and distribution. In restructured markets in particular, the utility conveying the benefit is not responsible for providing energy supply service to retail customers, so any incentivized device risks not capturing the full potential value of the ADER. • Risk of overcompensating participants at expense of non-participants since compensation depends on ratepayers as a whole and not on the value of the ADER to the service provided (cross-subsidization).
Availability Payments	• Customers have transparency and guaranteed income for their availability. • Availability payments incentivize DER owners to ensure their resource can be called on during events.	• Benefit is determined by utility and approved by regulators based on approximation (can be higher or lower than actual prices). • Risk of compensating resource even if not using it (similar to insurance). • Availability payments may limit options to participate in other ADER grid services.

181 Electric Power Research Institute, *Understanding Flexible Interconnection*, September 2018, https://www.epri.com/research/products/000000003002014475.

182 Xcel Energy, "Interruptible Service Option Credit," accessed April 19, 2024, https://co.my.xcelenergy.com/s/business/rate-plans/interruptible-service-option.

	Proponents' Comments	Opponents' Comments and Considerations
Up-front Incentives	• Simplest program design: the benefits are clear and transparent for customers. • Up-front incentives can be used to target ADER adoption for low- to moderate-income customers.	• Compensation may not include the full value of energy, capacity, transmission, and distribution. In restructured markets in particular, the utility conveying the benefit is not responsible for providing energy supply service to retail customers, so any incentivized device risks not capturing the full potential value of the ADER. • Risk of overcompensating participants at expense of non-participants since compensation depends on ratepayers as a whole and not on the value of the ADER to the service provided (cross-subsidization).
Availability Payments	• Customers have transparency and guaranteed income for their availability. • Availability payments incentivize DER owners to ensure their resource can be called on during events.	• Benefit is determined by utility and approved by regulators based on approximation (can be higher or lower than actual prices). • Risk of compensating resource even if not using it (similar to insurance). • Availability payments may limit options to participate in other ADER grid services.
Activation Payments	• Payments for specific activities, rewarding behavior changes. • Allows participants flexibility to respond or not respond to dispatch signal and be compensated accordingly. • Encourages innovation because there is flexibility in how ADERs respond to a dispatch signal to provide a grid service.	• Additional resources required to estimate change in energy use in order to compensate customers appropriately.
Penalties	• Act as a deterrent against non-delivery of grid services. • Can be tailored in severity to match the frequency of non-delivery (thereby not overly penalizing "first time offenses" relative to "repeat offenses").	• Customers need a very clear understanding of the risks of the agreement they are entering into. This may require specific regulatory oversight. Penalties may not be a good fit for residential participants. • May create a disincentive to participate in ADER grid services programs if customers deem the risk of receiving penalties is deemed too high.

Can ADERs be compensated using both prices and programs?

Prices and programs can interact in three key ways:

1. ADERs may respond to both prices and programs within a single arrangement.
2. ADERs may respond to different prices and programs managed by different entities.
3. ADERs may respond to different prices and programs at separate times.

For example, a single arrangement may consist of an up-front incentive coupled with a price signal, providing a strong signal for ADER grid service participation.

ADERs may also respond to different prices and programs that are providing grid services to support different entities. For example, a TOU tariff may help a distribution utility manage grid constraints, with the DER also able to participate in wholesale markets as part of an ADER portfolio.

The same DER may participate in price and programs at different times. For example, a program may require device activation during the set hours of 6 to 8 p.m. on weekdays when a battery storage device must export to the grid; however, during the remainder of the week, the battery storage device may respond to a TOU tariff. Alternatively, a device might be required to respond first to a utility's distribution peak demand, but may also be allowed to participate through a utility in reducing energy costs. Therefore, it is key to align on clear dispatch prioritization.

Policymakers should consider the holistic arrangement from both prices and programs to meet grid service requirements. The Hawaii Next Generation ADER programs are a good example of combining prices and programs—see the DER Programs Evolution (Hawaii) section in the case studies annex.[183]

Which compensation approaches are applicable to my state?

Programs and prices exist in all three cohort types, and both can be appropriate depending on a variety of factors. Determining which compensation approach is most appropriate for achieving state policy mandates cost-effectively may include considering the grid service requirements, customer base, the markets set up for ADERs, and penetration of DERs and intermittent renewable energy. For example, direct market participation is only possible in states with organized markets and contingent on their participation rules. It may also be necessary to adjust compensation mechanisms as marketplaces change, DER penetration increases, and smart devices become more common.

Table 17 illustrates examples of prices and programs for each cohort.

Table 17: Examples of Prices and Programs in Each State Cohort

	Jade: Organized markets; restructured	Coral: Organized markets; vertically integrated	Turquoise: Outside of organized markets; vertically integrated
Program examples	Massachusetts Connected Solutions Program[184] • Up-front incentives • Direct load control • Third party implements program on behalf of utility.	Vermont BYOD program[185] • Up-front incentives • Direct load control • Utility implements program	Hawaii Fast Demand Response Program[186] • Pay for performance • Autonomous load control • Third party implements program on behalf of utility.
Prices examples	Octopus Energy GridBoost in Texas[187] • Enroll battery in an Octopus Energy plan, and Octopus will optimize battery export timing based on real-time price signals from the grid.	CEC MIDAS Rates Database in California[188] • Database that includes all time-varying rates in California • Enables widespread automation in response to TOU rates	Hawaii Smart DER Rate[189] • Export credits vary based on time of day and must come from renewable resources. • Can be combined with the Hawaii BYOD program to provide customers with additional incentives for providing grid services.

183 See DER Program Evolution Case Study for Hawaii in the annex for additional detail.

184 See Connected Solutions Case Study in the annex for additional detail.

185 See GMP Case Study in the annex for additional detail.

186 Hawaiian Electric, "Fast Demand Response," accessed April 19, 2024, https://www.hawaiianelectric.com/products-and-services/customer-incentive-programs/fast-demand-response.

187 Octopus Energy, "Power Your Home Battery with Octo GridBoost," accessed April 19, 2024, https://octopusenergy.com/octo-gridboost.

188 California has developed a MIDAS that devices can connect and respond to that provides historical, current, and forecasted time-varying rates, GHG emissions from electrical generation, and California flex alert signals. CEC, "MIDAS."

189 Hawaiian Electric, "Smart Renewable Energy Export," accessed April 19, 2024, https://www.hawaiianelectric.com/products-and-services/smart-renewable-energy-programs/smart-renewable-energy-export.

How do I determine if a customer or an aggregator delivered a grid service? How do I determine how much to pay a customer for "pay-for-performance"?

For participants that are paid based on the grid service that they provide, the program implementer or market operator may need to verify whether the ADER participant provided the grid service that was previously agreed upon. For example, in a demand response program where a customer is paid to reduce their load during an event, the program implementer may need to verify how much load the customer actually shed when the event was called. This process is also known as evaluation, measurement, and verification (EM&V). It can assess the effectiveness of different pricing strategies and programs, and also ensures that participants are appropriately compensated for the grid services they provide. To measure the grid service provided by an ADER, evaluators typically use a counterfactual scenario.

Like valuation of "avoided costs," counterfactual scenarios are used to determine what would have happened in the absence of an ADER. The difference between the counterfactual scenario and what actually happened is the grid service that the ADER provided as a result of the pricing or program structure. This scenario, or "baseline," is used to verify the delivery of a grid service by ADERs and ensure that any activation payment is correctly calculated. Monitoring and verification equipment, such as advanced metering infrastructure, is used to assess both the baseline and the grid service delivery.

Various methodologies exist to determine a baseline.[190] Many in use refer to customer data on a similar weather day to create a view of what a DER would likely be doing if it had not responded to a grid service requirement. Some common baseline methods are shown in **Table 18**.

Table 18: Summary of Common Baseline Methodologies

Method	Description	Appropriate DERs	Additional Resources/Tools
Net Metered Energy Consumption (NMEC)	Baseline is developed using a regression model based on a "baseline period" prior to DER being installed/used.	DERs that lead to permanent changes in a customer's load shape. Historically has been used for energy efficiency.	Open EEMeter[191] California's NMEC Rulebook[192]
Historical Baseline	Baseline is based on the ADER's average consumption over past "event-like" non-event days. The specific number of days is determined by the baseline method.	Dispatchable resources that are not dispatched every day, such as demand response.	NYISO Baseline Methodology[193]
Control Group	Baseline is based on non-participant energy consumption, either pre-determined through program design or matched after the fact.	All	ERCOT Baseline Methodologies[194]

190 The Centre for Net Zero assessed key baselining methodologies; Center for Net Zero, "Baselining," accessed April 19, 2024, https://www.centrefornetzero.org/work/baselining/#:~:text=Centre%20for%20Net%20Zero%20wants,household%20on%20a%20specified%20day.

191 LFEnergy, "OpenEEmeter," accessed April 19, 2024, https://lfenergy.org/projects/openeemeter/.

192 CPUC, *Rulebook for Programs and Projects Based on Normalized Metered Energy Consumption*, January 7, 2020, https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/n/6442463694-nmec-rulebook2-0.pdf.

193 Mathangi Srinivasan Kumar, *Demand Response,* NYISO, March 5–8, 2024, https://www.nyiso.com/documents/20142/3037451/9-Demand-Response.pdf.

194 ERCOT, *Demand Response Baseline Methodologies*, October 2023, https://www.ercot.com/files/docs/2023/10/31/demand_response_baseline_methodologies_october_2023_tg-edit.docx.

Method	Description	Appropriate DERs	Additional Resources/Tools
Nomination	Baseline is the forecasted generation or demand profile of a DER if it were not utilized for a grid service. The forecast needs to be provided ahead of the DER being dispatched.	Generation DERs, such as solar	DNV GL Baseline Methodology Assessment[195]

Importantly, a baseline should be set prior to notification that an activation will take place. For example, grid services with activation payments scheduled a day ahead should have a defined baseline for the DER, so the DER owner or aggregator managing the DER does not manipulate load to create a larger difference between the baseline and activation of the DER. Similarly, any reduction in the difference between the baseline and activation should not unfairly reduce compensation paid to a DER owner. Policymakers may need to scrutinize baselining methodologies to ensure they do not adversely affect either ratepayers or ADER grid service providers.

Conclusion

The landscape of ADER technologies and the grid services they provide is still evolving, but there is already a wealth of knowledge and experience that showcase what ADERs are capable of.

This report provides a foundational overview of ADER grid services, valuation methodologies, and compensation approaches. Throughout, the reader is directed to further resources to develop a deeper understanding of the material. The annexed case studies provide examples of how policymakers have developed policies and regulations, outlining the tangible steps that decision-makers have taken in different regulatory contexts.

ADERs will continue to evolve in the coming months and years; the information in this report is designed to assist policymakers navigate complex and changing policy issues and support their priority policy outcomes.

195 *Baseline Methodology Assessment*, DNV GL, December 21, 2020, https://www.energynetworks.org/assets/images/ON20-WS1A-P7%20Baselining%20Assessment-PUBLISHED.23.12.20.pdf.

Annex: Case Studies

Green Mountain Power BYOD and Energy Storage System Programs (Vermont)[196]

Key Takeaway: Green Mountain Power's (GMP) *Bring Your Own Device (BYOD)* and *Energy Storage System (ESS)* programs demonstrate the power of flexible ownership models and robust incentives leading to high customer adoption in a state with high exposure to extreme weather.

Background

GMP, a B-corporation-certified investor-owned utility in Vermont, operates two home energy storage programs. The two programs began as pilots in 2015 and were implemented as full programs in 2020. The two programs collectively now have more than 3,000 participants and provide more than 30 MW in capacity reduction.[197]

GMP's *BYOD* program is an "open access" program offering customers an incentive of up to $10,500 in exchange for allowing GMP to operate their battery during peak periods. The *ESS* program allows customers to lease a battery system from GMP for 10 years, for $5,500 as an up-front payment or $55 per month, in exchange for GMP's ownership and operation of the battery. The *ESS* program is unique because GMP owns and operates the devices, while making battery storage more accessible to customers who cannot afford to purchase a battery on their own.

Both programs reduce costs for all GMP customers by providing capacity and transmission benefits that GMP then passes 100% along to customers to lower costs and carbon for all. Both programs also provide participating customers with backup power during outages in Vermont due to extreme weather.[198]

Annex Table 1: Green Mountain Power *BYOD* and *ESS* Programs at a Glance

Element	Green Mountain Power
Cohort	Coral (within an organized market and utilities own some generation assets)
Price or Program?	Program
Incentive Structure[199]	**BYOD:** Up-front incentive of up to $10,500 **ESS:** Leased Powerwall at a reduced cost of $5,500 (or $55/month for a 10-year lease with up to an additional five years at no extra cost)
Load Control Method	Direct control
Program Designed By	Green Mountain Power
Program Implementer	Green Mountain Power
DERMS Provider	**BYOD:** Virtual Peaker **ESS:** Tesla
Customers Served	Residential
Technologies Included	Battery storage

196 An interview with a representative of GMP was used to inform the case study.

197 Capacity and enrollment as of April 2024, from correspondence with GMP.

198 Vermont residents experienced an average of eight hours without power each year as of 2019; Aytek Yuksel, "10 U.S. States with the Longest Power Outages," *Cummins Newsroom, August 28, 2019*, https://www.cummins.com/news/2019/08/28/10-us-states-longest-power-outages.

199 Incentive structure for the program as of April 1, 2024.

Element	Green Mountain Power
Level of Grid Services Provided	Bulk power, grid edge
Grid Services Provided	Generation Capacity (through reducing peak loads) • Reduced capacity obligation (ISO-NE Capacity Auction) • Reduced transmission charges for GMP service territory resilience

Impetus for the Program

GMP championed both the *BYOD* and *ESS* programs with the overall goals of customer cost reductions and resilience benefits. Vermont is a state vulnerable to outages from severe weather. As a utility serving many rural customers, GMP was looking for a way to continue to provide reliable power to remote customers while also driving down costs for both participating and non-participating customers, combined with new flexible tools to manage a distributed grid.

Program Design and Valuation

GMP was able to fund the pilot phase of the programs through the Innovative Pilot provision in their regulation plan, a specific approach that allows non-tariffed funding for pilots that "advance the goals of Vermont's state energy policy, including the Renewable Energy Standard, or are otherwise designed to enable such programs in the future or to improve equity of access to renewable and clean energy programs for low- and moderate-income communities."[200] The pilot aimed to prove that GMP was able to manage customer-sited batteries for the benefit of all of their customers.

The Vermont Department of Public Service released a report in 2017 listing the benefits that storage could provide to the grid.[201] GMP was able to maximize the programs' capacity benefits by stacking two of the monetized values listed in the report:

1. **Forward Capacity Market:** The *BYOD* and *ESS* programs reduce GMP's capacity obligation in the forward-capacity auction administered by ISO New England three years ahead by reducing GMP's load during the peak hour.[202]
2. **Regional Network Service:** Both programs reduce transmission charges by reducing utility demand during regional monthly peak loads. The utility is charged based on peak load during the coincident peak each month, and by reducing utility load during that time, GMP was able to save on transmission costs.[203]

Other potential value streams include frequency regulation, ancillary services, and energy arbitrage. In 2021, GMP implemented a new pilot that uses a portion of the battery fleet to participate in the ISO New England frequency and regulation market, which makes use of frequency regulation and other ancillary services, and could expand going forward.[204] Resilience, while considered a valuable benefit for battery storage, was

200 See attachment 2 of GMP, *Green Mountain Power: Multi-Year Regulation Plan 2023–2026, October 1, 2022*, https://greenmountainpower.com/wp-content/uploads/2024/01/Final-2023-Regulation-Plan-as-amended-March-30-2023.pdf.

201 Vermont Department of Public Service, *Act 53 Report: A Report to the Vermont General Assembly on the Issue of Deploying Storage on the Vermont Electric Transmission and Distribution System*, November 15, 2017, https://legislature.vermont.gov/assets/Legislative-Reports/Storage-Report-Final.pdf.

202 ISO New England, "Forward Capacity Market," accessed April 19, 2024, https://www.iso-ne.com/markets-operations/markets/forward-capacity-market.

203 Vermont Department of Public Service, *Act 53 Report*, 2017.

204 GMP, "GMP's Pioneering Network of Powerwall Batteries Delivers First-in-New-England Benefit for Customers & Grid, Cutting Carbon and Costs," May 13, 2021, https://greenmountainpower.com/news/network-of-powerwall-batteries-delivers-first-in-new-england-benefit-for-customers/#:~:text=GMP's%20pioneering%20new%20Frequency%20Regulation,safety%20and%20reliability%20for%20customers.

not included as a monetary benefit of storage in the 2017 battery storage report.[205] Therefore while GMP considered resilience to be a benefit, it was not included in its approved BCAs.[206]

Using the monetary value streams, GMP estimated the total value the batteries were able to provide over a 10-year time frame. They designed incentive values by allocating approximately 80% of the benefits to the participants and 20% of the benefits to the non-participants to ensure all electric customers in their territory—whether they participate in the programs or not—were able to realize benefits from the programs.[207] Another key consideration was how to value the batteries given that the incremental value of adding another battery to the VPP decreases as the overall size of the VPP grows, due to the law of diminishing returns. (For example, the first battery enrolled is more valuable than the 1,000th battery enrolled.) In the end, they settled on a flat incentive value for all participants, regardless of when they enrolled.

Advantages and Obstacles to Setting up an ADER in Vermont

Given Vermont is a relatively small state, there were several unique aspects of the GMP programs. First, utility battery ownership was a point of contention when first designing the program since utilities traditionally do not own assets "BTM." However, GMP noted that because Vermont is so small, it likely would not attract a large market for third-party aggregators to operate in, and the utility could provide immediate benefits to its customers instead of waiting for that market to grow. Second, there was a cap on customer enrollment in the BYOD and ESS programs from 2020 to 2023. This was due to the small market in Vermont and placed a limit to the capacity benefits the *BYOD* and *ESS* programs can provide. The cap was lifted in 2023 due to the programs' ability to provide grid support during peaks and provide customers with backup power during outages.[208] Third, the smaller community in Vermont created a "Vermonters for Vermonters" mentality, which led to more faith in GMP to facilitate the program and a high rate of adoption.

Lessons Learned from Operating an ADER in Vermont

Since developing its battery storage programs, GMP has collaborated with other utilities such as Liberty Utilities in New Hampshire to help them implement similar programs. This type of collaboration between utilities is necessary to ensure programs avoid reinventing the wheel and build off prior successes. Additionally, GMP found that iterating on program design in the pilot phase and soliciting feedback from different stakeholder groups helped prepare them for making a case for full program rollout.

GMP also demonstrated that utility battery ownership can be a successful business model in their territory that benefits all of its customers and is popular with program participants. More than 3,000 customers have enrolled in the ESS program (compared to ~400 BYOD participants).[209] As noted above, GMP was approved to lift its cap on program participants in 2023 as demand for both the BYOD and ESS programs have outpaced the program caps, with more than 1,000 customers on the waitlist for the ESS program prior to the cap being lifted.[210]

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205 Vermont Department of Public Service, *Act 53 Report,* 2017.

206 State of Vermont Public Utilities Commission, Estimates of Revenues and Costs - Rule.2401(c), 2019, Attachment 2 and Attachment 4.

207 State of Vermont Public Utilities Commission, Case No. 19-3167-TF and Case No. 19-3537-TF, "Final Order," May 20, 2020.

208 GMP, "GMP's Request to Expand Customer Access to Cost-Effective Home Energy Storage Through Popular Powerwall and BYOD Battery Programs is Approved," *August 18, 2020,* https://greenmountainpower.com/news/gmps-request-to-expand-customer-access-to-cost-effective-home-energy-storage-is-approved/.

209 Enrollment numbers are from April 2024.

210 Ethan Howland, "Vermont PUC Lifts Cap on Green Mountain Power Battery Storage Programs with Tesla, Others," *Utility Dive,* August 29, 2023, https://www.utilitydive.com/news/vermont-puc-green-mountain-power-gmp-battery-storage-programs-tesla/692052/.

Connected Solutions Program (Massachusetts)[211]

Key Takeaway: The *Connected Solutions* program demonstrates how robust pilot testing and iteration can lead to long-term program success. The multi-device-type nature of the program enabled high levels of participant uptake.

Background

The *Connected Solutions* program was piloted by Massachusetts' three investor-owned utilities—Eversource, National Grid, and Unitil —from 2016 through 2019, until its official program launch in 2019. A precursor to the *Connected Solutions* program was initially designed in response to winter price spikes due to extreme weather between 2012 and 2014. The state's Active Demand policy then evolved and led to the development of the Connected Solutions program, which now has more than 400 MW of controllable peak load between its different technologies, customer types, and shifting strategies.[212] The Connected Solutions program was one of the first programs in the country to leverage energy efficiency funding to implement an active demand management program. The Connected Solutions program has continued to incorporate new technologies, including EVs as vehicle-to-grid technologies become more available, into its portfolio.

Annex Table 2: Connected Solutions Program at a Glance

Element	Connected Solutions
Cohort	Jade (within an organized market and utilities own very few generation assets)
Price or Program?	Program
Incentive Structure[213]	Up-front incentive: • $50/customer for residential smart thermostats + $20 for each year customer continues to be enrolled in the program Performance-based payments: • $275/kW reduced per summer for residential battery storage • $35/kW for C&I demand response targeted dispatch214 • $200/kW C&I demand response daily dispatch
Load Control Method	Direct control via aggregator
Program Designed By	Massachusetts Department of Energy Resources (DOER) and Massachusetts investor-owned utilities
Program Implementer	Massachusetts investor-owned utilities (Eversource, National Grid, and Unitil)
DERMS Provider	EnergyHub
Customers Served	Residential, Commercial, and Industrial
Technologies Included	Battery storage, smart thermostats, with option to add any devices that are technology-ready for EnergyHub to dispatch
Level of Grid Services Provided	Bulk power
Grid Services Provided	Generation Capacity

211 An interview with a representative from the Commonwealth of Massachusetts was used to inform this case study.

212 National Grid, *VPPs: Insights on Planning and Implementation,* February 28, 2024, presented at NARUC 2024 Winter Policy Summit.

213 Incentive structure as of April 1, 2024.

214 Incentives for the non-residential program vary by utility and can offer additional incentives, such as a $1,500 up-front incentive to help pay for metering for Eversource customers. Mass Save, "Program Materials for Connected Solutions for Commercial/Industrial Customers," August 31, 2021, https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/connectedsolutions-ciprogrammaterials.pdf.

Impetus for the Program

Precursors to the *Connected Solutions* program were designed in response to winter price spikes during 2012–2014, which led to concerns around affordability due to customer exposure to high wholesale market prices.[215] The Massachusetts *Green Communities Act of 2008* formally associated demand reduction with energy efficiency.[216] Because authority to manage demand under the energy efficiency umbrella preexisted the need, Massachusetts was able to leverage energy efficiency funding to procure the resource. The Department of Energy Resources (DOER) designed several pilots to see how they could more actively manage demand. In the interim between initial active demand response pilots and full-scale programming, DOER funded innovation in the demand management space more broadly through its Peak Demand Management Grant Program. DOER provided $4.68 million worth of grant funding to nine entities to test how to provide grid services associated with peak demand, including deferring transmission and distribution investments, wholesale capacity, and customer demand charges.[217] The successful demand management strategies tested in the grant program were integrated into *Connected Solutions* and will continue to inform changes in demand management programs going forward.

Program Design and Valuation

The *Connected Solutions* program design explicitly enables multiple device types to participate, rather than separating the program into device-specific sub-programs. This allows the program to aggregate a large number of heterogenous devices to provide a broad range of grid services.

The program design process included state agencies, utilities, and non-governmental organizations and was facilitated by the Massachusetts Energy Efficiency Advisory Council (EEAC).[218] As noted above, the investor-owned utilities also experimented with several different active demand management strategies in the pilot phase before selecting the design with which to move forward.

To fund the program under the *Massachusetts Green Communities Act*, the program needed to pass the Total Resource Cost test, so the EEAC worked with third parties to ensure the program provided the grid services needed to make the program cost-effective. The battery storage energy benefits included energy, capacity, transmission, distribution, and reliability benefits.[219] All of the energy benefits were estimated in the Avoided Energy Supply Cost Studies.[220] The primary benefit was reducing grid peak demand. Many non-energy benefits were also considered in the cost-effectiveness tests, including:

- Avoided power outages;
- Higher property values;
- Avoided fines;
- Avoided collections and terminations;
- Avoided safety-related emergency calls;
- Job creation; and
- Less land used for power plants.[221]

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215 Sam Evans-Brown, "New England Electricity Prices Spike as Gas Pipelines Lag," *NPR,* November 4, 2014, https://www.npr.org/2014/11/05/361420484/new-england-electricity-prices-spike-as-gas-pipelines-lag.

216 Commonwealth of Massachusetts, *An Act Relative to Green Communities,* Chapter 169, July 2, 2008, https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter169.

217 Commonwealth of Massachusetts, "Peak Demand Management Grant Program," accessed April 19, 2024, https://www.mass.gov/info-details/peak-demand-management-grant-program.

218 Massachusetts Department of Energy Resources (DOER), "MA Energy Efficiency Advisory Council," accessed April 19, 2024, https://ma-eeac.org/.

219 Elizabeth A. Stanton, *Massachusetts Battery Storage Measures: Benefits and Costs,* Applied Economics Clinic, July 31, 2018, https://www.cleanegroup.org/wp-content/uploads/Massachusetts-Battery-Storage-Measures-Benefits-and-Costs.pdf.

220 Synapse Energy, "Avoided Energy Supply Costs in New England (AESC)," accessed April 19, 2024, https://www.synapse-energy.com/avoided-energy-supply-costs-new-england-aesc.

221 Listed on page 12 of the Clean Energy Group's 2019 report; Olinsky-Paul, *Energy Storage, 2019.*

Additionally, the customer incentive structure was based on peak demand reduction rather than a rebate for purchasing a battery storage system to ensure storage was used to achieve the desired load reductions during peak.[222]

Advantages and Obstacles to Setting Up an ADER Program in Massachusetts

When the *Connected Solutions* program began in 2016, the technology for active demand management was not where it is today. Residential battery storage was still relatively new, and utilities were hesitant to implement programs with which they were not familiar. The pilot phase from 2016 through 2019 helped demonstrate its ability to achieve demand reduction goals and cost savings for customers.[223] The investor-owned utilities also leveraged the existing foundation for valuing and implementing managed DERs that was initially used to implement energy efficiency programs. While the energy efficiency foundation placed limitations on how the program could be implemented, this helped to kickstart the program and facilitate implementation, as it could be included in Massachusetts' three-year energy efficiency plan.

Lessons Learned from Operating an ADER Program in Massachusetts

Massachusetts continues to improve their demand management programs to meet broader grid and customer needs in the long term. Precursors to the Connected Solutions program were originally designed in response to a single issue and were more reactive than proactive. Changes to ADER programs going forward will take a more proactive stance and include more grid services to ensure that they will continue to lower costs for all customers and provide more valuable grid services. In the meantime, *Connected Solutions* continues to have clear grid value, and the Avoided Energy Supply Cost studies will continue to set values for reducing grid peak demand and other grid services, and ensure that future program iterations are cost-effective.[224]

When starting out, the DOER noted that the real challenges to implementing a new program was ensuring that they had the authority to do so and making sure that they could use their authority to adapt the program as grid needs changed. The Massachusetts Legislature passed the 2008 *Green Communities Act* a full eight years before the DOER decided to use its authority to actively manage demand. The legislature ensured that demand management ADERs, including storage, qualified for energy efficiency program inclusion by explicitly adding them to the Act in 2018.[225] The act's flexibility has enabled them to develop more than 400 MW of resources in active demand management and continues to allow the DOER to explore how they can manage demand to provide additional grid services, such as transmission and distribution deferral.

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222 See page 16 of the Clean Energy Group's 2019 report for more detail on program design considerations. Olinsky-Paul, *Energy Storage, 2019.*

223 Evaluations of the programs confirmed the technical feasibility of these programs and estimated their program savings. An example of this report is the 2018 Summer Thermostat Optimization Evaluation; Navigant, *2018 Massachusetts Summer Thermostat Optimization Evaluation*, March 29, 2019, https://ma-eeac.org/wp-content/uploads/2018-MA-TO-Evaluation-Report-2019-03-29-Final.pdf.

224 Synapse Energy, "Avoided Energy Supply Costs in New England (AESC)."

225 Commonwealth of Massachusetts, *An Act to Advance Clean Energy,* August 9, 2018, https://malegislature.gov/Laws/SessionLaws/Acts/2018/Chapter227.

DER Programs Evolution (Hawaii)[226]

Key Takeaway: Hawaii's DER program evolution demonstrates how leveraging both ADER programs and prices can deliver cost savings and resilience benefits to customers in an isolated geography with high DER adoption rates.

Background

The Hawaii PUC has a long history of supporting the growth of DERs. The Hawaii PUC first launched net energy metering (NEM) in 2001, and the state now has more than 100,000 rooftop solar installations.[227] Due to the rapid expansion of DERs in the state, the Hawaii PUC decided to retire NEM in 2015 and adopted five new DER programs over the next few years that were intended to better leverage DER grid services. These included the *NEM Plus, Customer Self Supply, Customer Grid Supply, Customer Grid-Supply Plus*, and the *Smart Export* programs.[228] These programs were intended to be in place only for a short time as the state developed longer-term solutions.

After several years of multi-stakeholder deliberations across multiple dockets, the Hawaii PUC approved a series of next-generation DER programs, which are covered in this case study. First, the Hawaii PUC initiated the development of a Grid Services Purchase Agreement (GSPA) framework in 2018 focused on procuring a range of grid services through third-party aggregators. After a few rounds of procurements in 2020 through 2023, the PUC approved several GSPAs between Hawaiian Electric (HECO) and aggregators, such as Swell Energy which implements the *Swell Home Battery Rewards* program.[229]

In 2022, HECO also launched their *Battery Bonus DER* program to address expected near-term capacity shortfalls. Finally, in 2024, HECO launched two follow-on longer-term DER programs: *BYOD* and the *Smart DER* programs.[230] These next-generation DER programs were developed to directly replace fossil fuel generation resources as they were retired and provide grid services identified in HECO's integrated planning process. The new programs were designed to be more flexible for the evolving grid and unlock additional value streams for customers and the utility.

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226 An interview with a representative from Hawaii PUC was used to inform the case study.

227 Hawaiian Electric, *Building a Strong and Resilient Hawaii Together: 2022–2023 Sustainability Report,* 2022, https://view.hawaiianelectric.com/2022-2023-sustainability-report/page/4-5?_gl=1*1n8mug1*_ga*NzU4MzQ4NjIzLjE3MDczNDY4MDc.*_ga_8VKC9WNWB9*MTcwOTMxNzYxMi44LjAuMTcwOTMxNzYzMy4wLjAuMA.

228 These programs expedited solar installations for customers that did not use solar to export to the grid, compensated net exporters at a rate more similar to avoided costs, and allowed customers to install solar + storage systems. See Chapter 2 of *Powering Paradise for more information on the history of DER programs in Hawaii. Dan Cross-Call, Jason Prince, and Peter Bronski, Powering Paradise: How Hawaii Is Leaving Fossil Fuels and Forging a Path to a 100% Clean Energy Economy,* RMI, 2020, https://rmi.org/insight/powering-paradise.

229 Docket approving GSPA with Swell Energy: Public Utilities Commission of the State of Hawaii, Docket No. 2022-004, March 16, 2022, https://hpuc.my.site.com/cdms/s/puc-case/a2G8z0000007f2dEAA/pc20416?tabset-a3299=3. Swell Home Battery Rewards Program Website, "Join the Swell Energy Home Battery Rewards Program Today!," Swell Energy, accessed April 18, 2024, https://www.swellenergy.com/hi/. Additional Power Partnership Programs can be found at "Power Partnership Programs," Hawaiian Electric, last accessed April 18, 2024, https://www.hawaiianelectric.com/products-and-services/customer-incentive-programs/power-partnership-programs.

230 Public Utilities Commission of the State of Hawaii, "DER Programs," last updated March 2024, https://puc.hawaii.gov/energy/der/programs/.

Annex Table 3: Recent Evolution of Hawaii DER Programs at a Glance

Element	Battery Bonus	BYOD	Smart DER Program	Swell Home Battery Rewards Program
Cohort	Turquoise (outside organized markets where utilities own some generation assets)			
Price or Program?	Pricing + program	Pricing + program	Pricing	Program
Incentive Structure[231]	Up-front incentive ($850/kW) + export credits based on retail energy rate	Up-front incentive ($100/kW) + export credits based on the Smart DER rate	Export credits, compensated based on the Smart DER rate. Varies by island. On Oahu: • 9 p.m.–9 a.m.: 18.9 cents/kWh • 9 a.m.–5 p.m.: 13.5 cents/kWh • 5 p.m.–9 p.m.: 32.9 cents/kWh[232]	Activation Payments • Fast frequency response: $5/kWsc • Capacity build: $3/kW • Capacity reduction: $5/kW
Load Control Method	Customer control	Direct control or customer control	Customer control	Direct control (managed by Swell)
Program Implementer	HECO	HECO	HECO	Swell (through HECO)
Customers Served	Residential & commercial	Residential & commercial	Residential & commercial	Residential
Technologies Included	Battery storage	Battery storage & future smart tech as it becomes available	Any generating tech with or without storage; to export, generation must come from renewables	Solar + battery storage
Level of Grid Services Provided	Bulk power	Bulk power	Bulk power	Bulk power
Grid Services Provided	Capacity	Capacity build, capacity reduction	Energy	Fast frequency response, capacity build, capacity reduction

Impetus for the Programs

The four programs each came about for different reasons. As stated above, the *Swell Home Battery Rewards* program resulted from a competitively bid GSPA released by HECO.233 The GSPA aimed to use third-party aggregators to provide capacity build and fast frequency response grid services in addition to capacity reduction.[234]

231 Incentive structure for programs as of April 1, 2024.

232 Hawaiian Electric, "Smart Export," accessed April 18, 2024, https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/rooftop-solar/smart-export.

233 Matthew Mercure, "Swell Energy Secures Grid Services Contract with Hawaiian Electric," *Solar Industry,* January 18, 2021, https://solarindustrymag.com/swell-energy-secures-grid-services-contract-with-hawaiian-electric.

234 Public Utilities Commission of the State of Hawaii, Docket No. 2022-004, March 16, 2022, https://hpuc.my.site.com/cdms/s/puc-case/a2G8z0000007f2dEAA/pc20416?tabset-a3299=3.

The *Battery Bonus* program was part of a broader grid emergency services program and was developed to address capacity shortfalls brought about by the retirement of a coal plant on Oahu and an oil plant on Maui.[235] It was a shorter-term program, with implementation starting in 2022 and will close to new enrollment in 2024.[236]

The *BYOD* and *Smart DER* programs were designed as a part of an effort to improve upon DER program design in the long term. In 2019, the PUC opened a docket designed to investigate technical, economic, and policy issues around DERs in Hawaii. Their broad objectives included designing and implementing long-term DER programs that included both an export only program (*Smart DER*) and a more advanced program (*BYOD*).[237] Hawaii finalized the design of their *Smart DER* in December 2023 and is continuing to finalize the implementation details of the *BYOD* program as of April 2024.[238]

Program Design and Valuation

The *Battery Bonus, BYOD*, and *Smart DER* programs are implemented through HECO. Alternatively, the Swell Home Rewards program is implemented by Swell Energy on behalf of HECO, who can be penalized if they do not provide the grid services agreed upon in the GSPA. When designing each of the programs initially, the PUC set grid service targets and other program design parameters for HECO at the start of each proceeding, and then parties collaborated to design a program structure that would enable the utility to hit those goals. For example, in the *Battery Bonus* proceeding, the PUC provided guidelines on the program design elements that should be included in proposals, including the customer segments that should be included, the grid services the program needs to provide, the MW value the program targeted, and the program timing needs.[239]

Once the program structure was approved, the parties to the docket performed extensive modeling, reviewed in detail by the Hawaii PUC, to establish incentives and export rates based on pre-determined ADER benefits. There were eight value streams that were considered for the next-generation DER programs:

- Energy generation impacts;
- Capacity impacts;
- Renewable portfolio standard compliance impacts;
- GHG emissions impacts;
- Grid services;
- Transmission system impacts;
- Distribution system impacts; and
- Resilience impacts.

To reflect the evolving needs of the grid, the PUC built in flexibility to revisit elements, such as incentive levels and operational characteristics, every three years with stakeholders.

235 Public Utilities Commission of the State of Hawaii, Docket No. 2019-0323, "Decision and Order No. 37816," June 8, 2021, https://puc.hawaii.gov/energy/der/programs/.

236 Ibid.

237 Public Utilities Commission of the State of Hawaii, Docket No. 2019-0323, "Order No. 37066: Establishing Procedural Details and Modifying Hawaiian Electric's Customer Grid Supply Plus Program for Hawaii Island," April 9, 2020, https://puc.hawaii.gov/energy/der/programs/.

238 Public Utilities Commission of the State of Hawaii, Docket No. 2019-032, "Decision and Order No. 40418," December 4, 2023, https://hpuc.my.site.com/cdms/s/puc-case/a2G8z0000007fBFEAY/pc20950?tabset-a3299=3; and Public Utilities Commission of the State of Hawaii, Docket No. 2019-0323, *"Decision and Order No. 40626: Denying the Hawaiian Electric Companies' Motion for Clarification and Partial Reconsideration of Order Nos. 40582 and 40600," February 26, 2024,* https://hpuc.my.site.com/cdms/s/puc-case/a2G8z0000007fBFEAY/pc20950?tabset-a3299=3.

239 "Decision and Order No. 37816," 2021.

Advantages and Obstacles to Setting up an ADER Program in Hawaii

Because Hawaii's islands have isolated grids, the state is more vulnerable to outages from hurricanes and has very high electricity rates. Hawaiian residential electricity rates are 2.7 times the average U.S. residential rate.240 Both factors make DERs more appealing to customers given that investing in DERs can reduce customer electricity bills and provide resilient backup power during outages. Building on the early NEM adoption, when the PUC began to develop their next-generation DER programs, the state's solar network was well established and had a robust market.

Hawaii is navigating how programs and prices can interact with each other to influence customer behavior and provide customers with appropriate compensation. In addition to the DER programs, all customers are gradually moving to TOU rates, adding a layer of complexity for the optimal dispatch of ADERs for grid services.[241]

Lessons Learned from Operating an ADER in Hawaii

The Hawaii PUC found that engaging early and often with stakeholders was a key driver of successful program design. The PUC also learned that building flexibility into the process helps them update their programs as grid needs evolve. Finally, the multi-year process to develop the new DER programs highlighted the importance of integrating the multiple capabilities of DERs into utility planning processes, and in turn, using utility planning processes to inform program design. This coordination between programs and planning ensured that programs were designed to deliver specific grid services needed during different times of the day. Going forward, the PUC would like to better reflect the differences between customers on different islands in program design with a focus on setting up programs that address the unique needs of each island and its residents and businesses.

240 Calculated from November 2023 average Hawaii and U.S. residential customer prices; U.S. Energy Information Administration, "Electric Power Monthly," accessed April 18, 2024, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.

241 While some customers (like new DER customers) will be auto-enrolled in TOU, they will have the ability to opt out. The broader rollout for all customers has not happened as of April 2024, though the PUC has signaled its intention to do so in the near future. See "Order No. 40626: Denying the Hawaiian Electric Companies' Motion for Clarification and Partial Reconsideration of Order Nos. 40582 and 40600," 2024, https://shareus11.springcm.com/Public/DownloadPdf/25256/f01ca84c-05d5-ee11-b83e-48df377ef808/6c15d123-15d5-ee11-b83e-48df377ef808.

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