AN OVERVIEW OF BEHIND-THE-METER SOLAR-PLUS-STORAGE REGULATORY DESIGN

Approaches and Case Studies to Inform International Applications

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List of Acronyms

AHJ	authority having jurisdiction
APS	Arizona Public Service
BESS	battery energy storage system
CPP	critical peak pricing
CPS	clean peak standard
CPUC	California Public Utilities Commission
CSP	concentrating solar power
DBC	declining block charge
DER	distributed energy resource
DG	distributed generation
DPV	distributed photovoltaic
FERC	U.S. Federal Energy Regulatory Commission
GWh	gigawatt hours
IBC	inclining block charge
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor-owned utility
kW	kilowatt
MW	megawatt
NEM	net energy metering
NFPA	National Fire Protection Association
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
OPR	Governor's Office of Planning and Research
PSH	pumped storage hydropower
RPS	renewable portfolio standards
SCE	Southern California Edison
SGIP	Small Generator Interconnection Procedures
TOU	time-of-use
UPS	uninterruptible power supply
USAID	U.S. Agency for International Development

Executive Summary

Behind-the-meter energy storage systems paired with distributed photovoltaic (DPV)—with the capability to act as both generation and load—represent a unique and disruptive power sector technology capable of providing a range of important services to customers, utilities, and the broader power system. How should regulators, utilities, and policymakers manage the range of challenges and opportunities that increased behind-the-meter energy storage deployment will bring to the power system, in particular when these systems are paired with DPV? This report is intended to offer key regulatory considerations for facilitating DPV-plus-storage programs for retail customers; relevant cases from U.S. states are provided as examples of how novel regulatory issues related to behind-the-meter energy storage systems paired with DPV are being addressed in practice.

At a high level, designing a regulatory framework that aligns DPV-plus-storage deployment with larger policy objectives requires thoughtful deliberation across a range of technical and economic issues. While this report attempts to segment many of these issues into distinct topics to enhance reader understanding, in reality, DPV-plus-storage regulatory issues are all closely integrated, and design decisions on a single aspect often have broader implications. With that in mind, this report outlines a series of steps that can be employed by regulators to approach DPV-plus-storage regulatory design (see Figure ES- 1).

Figure ES- 1. Approaching regulatory design for DPV-plus-storage systems

Source: Original [*Illustration by Christopher Schwing, NREL]*

Policy and Market Context—The policy and market context into which DPV-plus-storage systems are being deployed will invariably influence the objectives regulators will want to pursue. Regulators can take into consideration the presence of stated policy goals, as well as local power system conditions, when considering their objectives and plans of action.

Step 1: Develop and Prioritize Regulatory Objectives—As a first step, developing clear regulatory objectives—which may be influenced by, aligned with, or directly derived from stated public policy goals—can help guide individual decisions on designing regulations. Batteries located behind the meter of a retail customer are technically capable of providing myriad services across all voltage levels of the power system. Regulators can consider a range of important objectives, including the desired role and behavior of DPV-plus-storage systems in the power system to provide services, appropriate levels of financial and administrative burdens for customers and utilities, utility cost recovery and cross-subsidization issues, and operational transparency and safety, among others.

Step 2: Design Compensation Mechanism—Next, regulators can consider the appropriate compensation mechanism offerings for DPV-plus-storage systems that attempt to address and balance objectives related to fair customer compensation and utility cost recovery, as well as the desired role of DPV-plus-storage in the power system. This report provides a broad overview of metering and billing arrangements, retail rate design options, and sell rate design options that may be relevant for DPV-plus-storage customers. Importantly, decisions surrounding compensation mechanisms influence rules related to metering and technical configuration requirements for DPV-plus-storage systems.

Step 3: Design Metering and Technical Configuration Requirements—Rules governing metering and technical configuration requirements for DPV-plus-storage can be designed to ensure the desired compensation mechanism can be implemented, and that the desired role of DPV-plus-storage systems will be realized in the power system. Technical configuration requirements affect the ability of DPV-plus-storage to interact with the grid by potentially restricting certain flows of energy, and ultimately influence the role that these systems can play in the power system. Metering requirements enable the implementation of compensation mechanisms and can be used to increase the visibility of DPV-plus-storage systems to the utility; however, they also have important cost implications for regulators to consider.

Step 4: Design Interconnection Process—Regulators play an important role in developing interconnection processes for DPV-plus-storage systems, in some cases directly driving these efforts and in other cases overseeing the utility's efforts. Designing a process for DPV-plus-storage systems to interconnect to the power system in a safe and orderly manner requires the development of: (1) rules governing the procedures that utilities employ to manage the interconnection application process; (2) rules governing how DPV-plus-storage equipment is expected to perform and interact with the power system; and (3) rules governing how interconnection applications are screened and evaluated, with a specific focus on how DPV-plus-storage systems will impact operations on the distribution circuit where the system will be interconnected.

Step 5: Consider Local Permitting Issues—While not directly under their purview, regulators must nevertheless account for the presence of local construction permitting processes, including compliance with relevant building, electrical, and fire safety codes. These codes are critical to ensuring that DPV-plus-storage systems perform safely and as expected, regardless of environmental conditions, and do not suffer performance degradation due to improper installation, operation, or transportation. While local permitting authorities may have developed familiarity with DPV systems, behind-the-meter storage is a new and evolving topic with which local governments may not have significant experience. Regulators can help build local capacity with storage systems by sharing information resources and contributing to the development of model permitting procedures.

Key Considerations for Regulators

Determine the desired role of DPV-plus-storage. Compared to grid-tied DPV systems, DPV-plus-storage has a significantly broader set of capabilities to offer customers and the power system, and regulators are often able to guide how these resources are ultimately utilized. Some regulators may wish to see DPV-plus-storage systems deployed to primarily or explicitly serve a customer's own energy demand, and/or for individual customer backup purposes during grid outages. Others may wish to enable DPV-plus-storage systems to provide grid services to the power system, or simply to preserve the option to do so in the future without expensive retrofits. In any case, determining the desired role of DPV-plus-storage systems upfront and ranking them in priority order, before various rules and regulations are advanced, can help to guide a range of decisions related to compensation mechanism design, metering and technical configuration requirements, and technical interconnection processes and requirements.

Customizing rules and requirements based on the characteristics of the DPV-plus-storage system is a key strategy for promoting fairness. Creating distinct sets of compensation mechanisms, metering and technical configuration requirements, and interconnection processes—which may be based on system size, the intended use of the system (e.g., an exporting versus non-exporting storage system), and other aspects—can help ensure regulatory requirements are appropriate for various segments of the DPV-plus-storage market.

Market context strongly influences compensation mechanism design and its timing. Solar penetration levels, grid management issues, storage deployment mandates or goals, distributed energy resource (DER) technology costs, utility cost recovery and cross-subsidization considerations, and low-income customer concerns are examples of factors that may drive regulators to consider certain design choices at certain times over others. For example, the presence of higher penetrations of solar photovoltaics may create certain grid management issues (e.g., the “duck curve”) that could motivate the utilization of more granular, cost-reflective rates (e.g., time-of-use [TOU] tariffs) and/or alternatives to net energy metering (NEM) to better align customer and grid system needs. On the other hand, jurisdictions which have financially insolvent utilities or significant cross-subsidy schemes in place may be more concerned with ensuring utility revenue sufficiency and avoiding cost-shifting, and may wish to encourage the use of customer-sited storage deployment primarily for self-supply and/or backup during grid outages. Importantly, early-stage DER markets may take different approaches to compensation mechanism design than mature DER markets, depending on these context-specific factors and needs.

Tariff design is the primary tool to align the interests of DPV-plus-storage customers with the broader power system. Relative to grid-tied DPV systems, the presence of a paired behind-the-meter storage system allows customers to better control the magnitude and timing of their electricity consumption from the grid, as well as their grid exports. TOU volumetric energy rates and coincident demand-based charges, if designed and implemented properly, can take advantage of this load shifting capability and incentivize DPV-plus-storage customers to act in a more grid-optimal manner (e.g., reducing consumption and/or increasing exports during typical peak demand periods). This behavior, as incentivized by time-variant tariffs, can help ease the management of DERs on the distribution system and also lead to a reduction in power system operational costs. Implementation of such tariffs may require new metering equipment and administrative responsibilities for utilities but can serve as a grid-friendly incentive for customers to install DPV-plus-storage systems.

Regulators can help balance common utility concerns with consumer interests, ensuring the implementation cost of solutions is commensurate with the scale of the issue being created. Utilities may raise concerns over issues such as compensation mechanism integrity, energy arbitrage activities, or inadvertent exports from storage systems. A variety of known solutions can be used to address these issues, but many of them involve additional expenditures by customers and/or new administrative burdens for utilities. Regulators are in a position to balance utility and customer interests and ensure that utility proposals to mitigate their concerns do not place an undue burden on participating and nonparticipating customers. For instance, while undesirable energy arbitrage could be mitigated through the deployment of additional metering equipment, the cost of installing additional metering equipment might be inappropriately high for smaller scale residential, commercial, or industrial customers.

Regulators can enable business model innovation for DPV-plus-storage systems. Regulators can play a key role in allowing alternative investment and ownership models for DPV-plus-storage systems. Many U.S. DPV assets have been deployed under third-party ownership models (either lease or power purchase agreement) whereby a utility customer does not actually own the asset but receives a portion of the benefit of the DPV generation. Third-party ownership models are already beginning to play a role in storage deployment in the United States, Australia, and elsewhere, both for retrofits and new-build DPV-plus-storage systems. In the future, these resources might be aggregated by third parties, who are allowed to do so to provide valuable services to distribution companies and/or the bulk power system. Regulators can play a key role in enabling the participation of aggregators, and, in some cases, defining how aggregators are allowed to operate.

Standardizing interconnection application forms, processes, and requirements may offer a variety of benefits. Doing so can reduce barriers to market entry for developers, as developers would only have to learn a single process for interconnecting prospective customers with utilities, as opposed to a separate process for all utilities in a particular market. Standardization may also reduce the number of incomplete or incorrectly completed applications that utilities must process, which both streamlines interconnection processes and reduces utility administrative burdens. On the other hand, creating and periodically updating standardized interconnection standards could be an additional burden for regulators to undertake. Furthermore, additional regulatory approvals may be required if specific utilities want to modify their standards to be more specifically catered to their situation.

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1 Introduction and Background

1.1 Purpose of Report

Behind-the-meter energy storage systems paired with distributed photovoltaic (DPV)—with the capability to act as both generation and load—represent a unique and disruptive power sector technology.[1] How should regulators, utilities, and policymakers manage the range of challenges and opportunities that increased behind-the-meter energy storage deployment will bring to the power system, in particular when it is paired with DPV systems?

This report has been prepared by the National Renewable Energy Laboratory (NREL) with support from the U.S. Agency for International Development (USAID) and is intended to offer key regulatory considerations for facilitating DPV-plus-storage programs for retail customers. Throughout the report, relevant cases from U.S. states are provided as examples of how novel regulatory issues related to behind-the-meter energy storage systems paired with distributed PV are being addressed in practice. Given the broad range of policy and market contexts in the United States and the variety of strategies adopted to reliably integrate DPV-plus-storage across these contexts, these jurisdictions may offer lessons for other U.S. states and the international community as they approach such issues in their own power systems. Importantly, broader strategies to reconceptualize regulatory frameworks—such as revenue decoupling[2] or performance-based regulation[3]—may be useful in supporting the sustainable integration of DPV-plus-storage into power systems. These strategies are discussed briefly in Section 2.3.2, but are not the focus of this report.

Section 1 discusses how batteries, in particular lithium-ion batteries, fit into the larger environment of energy storage technologies, outlines the various system services that batteries can provide, discusses the concept of value stacking, and provides context on the U.S. energy storage market, as well as expectations of global growth in energy storage deployment.

Section 2 outlines the regulatory design process, discusses how policy objectives can influence downstream decisions such as compensation mechanism design, and highlights important tools available to decision makers to customize regulations to fit specific market and power system contexts.

Section 3 discusses various potential regulatory objectives for DPV-plus-storage programs and describes a general framework for approaching DPV-plus-storage regulatory issues.

Section 4 reviews various considerations for the design of DPV-plus-storage compensation mechanisms.

Section 5 explores a range of technical considerations, strategies, and approaches for developing metering and technical configuration requirements for DPV-plus-storage systems.

Section 6 discusses the development of interconnection processes and technical requirements for DPV-plus-storage.

Section 7 briefly describes local permitting issues surrounding DPV-plus-storage systems.

Section 8 reviews a range of policy instruments and approaches to encourage DPV-plus-storage deployment.

Section 9 offers a summary of key regulatory considerations for DPV-plus-storage systems.

1.2 Energy Storage Technology Environment

Energy storage systems are technologies capable of charging energy from an external source and discharging this energy at a later time, after some amount of the initial energy is lost. Energy storage systems can be broadly

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[1] This report defines behind-the-meter storage as a stationary electrochemical storage system connected directly to a retail consumer of grid electricity, as opposed to systems installed on the grid side. The term behind-the-meter derives from the idea that user-side systems are 'behind' the user's utility service meter from the perspective of the utility.

[2] See Revenue Regulation and Decoupling: A Guide to Theory and Application prepared by the Regulatory Assistance Project (Lazar et al., 2016).

[3] See Next Generation Performance-based Regulation prepared by the Regulatory Assistance Project and NREL (Littell et al., 2017).

categorized based on: (1) the type of energy they store (e.g., thermal, mechanical, electrical, or electrochemical energy); or (2) where they are interconnected (e.g., in front-of-the-meter, behind-the-meter, or off-grid). These are distinct from demand response initiatives, which seek to shift energy consumption to better match the supply of cheap or clean electricity, but do not directly store energy for later use.

Mechanical energy storage systems, such as pumped storage hydropower (PSH), compressed air energy storage, and flywheels, have historically been the most common forms of energy storage around the world, in particular PSH. PSH uses electricity to pump water from a lower-elevation reservoir to a higher-elevation reservoir and then releases the water from the high reservoir to turn hydroelectric turbines to generate electricity at a later time. Compressed air energy storage systems use electricity to store air in a reservoir, either in underground caverns or in aboveground containers. The compressed air can then later be directed through a turbine to generate electricity. Flywheels use electricity to accelerate a rotor in a very low friction environment and electricity can be extracted from the flywheel by decelerating the rotor. Mechanical energy storage systems are typically utilized in larger scale front-of-the-meter projects, with the exception of flywheels, which may be used behind-the-meter as an uninterruptible power supply (UPS)[4] in certain critical infrastructure settings (e.g., hospitals).

Electrochemical storage systems use a series of reversible chemical reactions to store electricity in the form of chemical energy. Batteries are the most common form of electrochemical storage and have been deployed in power systems in both front-of-the-meter and behind-the-meter applications. Various battery chemistries are explained in the subsequent section.

Electrical energy storage systems store electricity either in the electric field of a supercapacitor or in the magnetic field of a superconductor for extremely short durations. At a high level, most electrical energy storage systems are capable of holding charges for long periods of time but can only discharge at their full capacity for very short durations (e.g., seconds or minutes). In power systems, supercapacitors are typically deployed as a UPS, in combination with other storage technologies such as batteries to improve the response and operation of the storage system or to help buffer fluctuations in power supply or demand. Similar to supercapacitors, superconducting magnetic energy storage is typically used in quick-response, very short duration applications, such as ensuring power quality. These storage systems are relatively new and have seen limited deployment in the power system. Furthermore, given their price and short durations they are not expected to play a large role in behind-the-meter settings except for isolated commercial and industrial customers with stringent power quality needs.

Thermal energy storage systems work either by raising or lowering the temperature of a material or by inducing a phase change in a material. Thermal energy can be stored in this material on timescales from hours to seasons based on the size of the system and can be used to meet heating or cooling demands or to generate electricity through the creation of steam from stored heat. It can be implemented using a range of technologies and approaches. For electricity generation, this technology suite is typically utilized in larger-scale front-of-the-meter projects, often in combination with generating technologies, such as combining molten salt thermal energy storage with concentrating solar power (CSP) plants.

Figure 1 shows several storage systems and their suitability for distributed applications.

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[4] UPS refers to a source of backup power that is used to ensure continuous availability of power in the event of an interruption of service. UPS typically only have enough energy to operate for a few to several minutes while backup generation source or other storage systems become activated (Akhil et al. 2013).

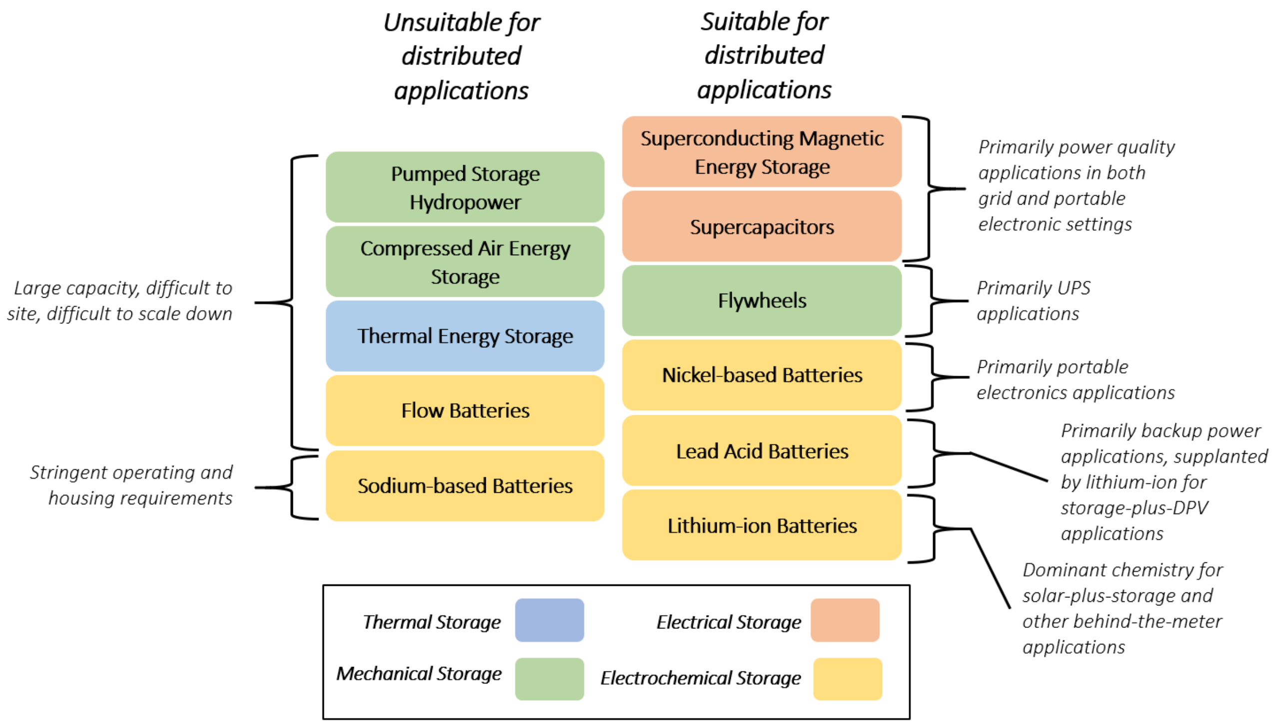

Figure 1. Storage technology types and applications organized by storage medium

Source: Original [*Illustration by authors]*

This figure is not intended to provide an exhaustive list of all storage technologies. Furthermore, there are a range of potential technological approaches and/or chemistries within each of the technology types illustrated.

1.2.1 Increasing Prominence of Electrochemical Battery Storage

Although there is a wide array of storage technologies available, storage deployment has historically been dominated in terms of capacity by utility-scale PSH systems connected to medium- or high-voltage networks; however, despite this historical focus on PSH, new installations around the world increasingly use electrochemical battery storage technologies, both in large-scale grid-side (i.e., front-of-the-meter) and smaller user-side (i.e., behind-the-meter) applications.

Battery storage systems encompass many different chemistry types, including lithium-ion, lead-acid, nickel-based, sodium-based, and redox flow. Each of these chemistries differs in their technical characteristics, a few examples of which are displayed in Table 1, and each have their own relative advantages and disadvantages that make them suitable for different grid system applications. Furthermore, within each battery chemistry category listed, there are many different sub-chemistries that will vary in their technical characteristics and considerations. For instance, among nickel-based chemistries, the performance and environmental concerns for Nickel-Cadmium (Ni-Cd) batteries will differ compared to Nickel-Metal Hydride (Ni-MH) batteries. A full consideration of each battery chemistry or of all the relevant technical characteristics of each battery chemistry (i.e., temperature and depth-of-discharge effects or charging times) is outside the scope of this report.[5]

[5] For information on battery chemistries and their relative advantages, see: (Akhil et al. 2013); (Kim et al. 2018).

Table 1. Definitions of Key Battery Technical Characteristics	
Rated Power Capacity	Total possible instantaneous discharge capability (in kilowatts [kW] or megawatts [MW]) of the battery energy storage system (BESS), or the maximum rate of discharge that the BESS can achieve, starting from a fully charged state.
Energy Capacity	Maximum amount of stored energy (in kilowatt-hours [kWh] or megawatt-hours [MWh]) a battery can hold (capacity may also be represented as 'Usable Energy Capacity' or 'Operating Energy Capacity' that reflects the highest percentage of the total energy capacity recommended to preserve battery performance).
Energy/Power Density	Measure of the energy or power capacity of a battery relative to its volume (kW/L, kWh/L).
Specific Energy/Power	Measure of the energy or power capacity of a battery relative to its weight (kW/g, kWh/g).
Storage Duration	Amount of time storage can discharge at its rated power capacity before depleting its energy capacity.
Cycle Life/Lifetime	Amount of time or cycles a battery storage system can provide regular charging and discharging before failure or significant degradation.
Round-trip Efficiency	Ratio of the energy charged to the battery to the energy discharged from the battery.
Self-discharge	Reduction of stored energy of the battery (% of charge/time) through internal chemical reactions, rather than through discharging to perform work.

Although the global market for stationary[6] energy storage by cumulative capacity is still dominated by large-scale PSH, lithium-ion batteries have, in recent years, become the most common newly installed battery technology for power sector applications, deploying in both front-of-the-meter and behind-the-meter applications. Compared to other battery technologies, lithium-ion batteries are characterized by very high energy densities, moderate power densities, a moderate cycle life, high round-trip efficiencies, moderate (and quickly declining) costs, and low maintenance requirements. The efficiency and capacity of these chemistries is not as strongly impacted by the depth-of-discharge compared to other battery chemistries, such as lead-acid or nickel-based. Lithium-ion batteries are relatively safe but have the potential for thermal runaway, in which the temperature inside the battery cells becomes hot enough to cause self-sustaining heat generation, which can lead to fires or explosions. Despite safety concerns, lithium-ion has emerged as the primary battery chemistry for behind-the-meter applications, including DPV-plus-storage systems. Current research into lithium-ion energy storage is investigating cell chemistries and designs that are less susceptible to thermal runaway (Goldie-Scot and Curry 2015). Likewise, safety codes have been developed to ensure that thermal runaway does not lead to dangerous fires or explosions.[7] Careful design and appropriate safety codes can support a safer, but not foolproof, configuration. Reuse, recycling, and safe disposal of lithium-ion batteries may also be important issues for regulators but are beyond the scope of this report.

Lead-acid batteries have seen deployment in the power sector primarily for off-grid, as well as emergency and backup power applications. They have largely been supplanted in DPV-plus-storage systems and residential customer applications by lithium-ion chemistries. Compared to other battery chemistries, lead-acid batteries exhibit low energy densities, very high-power densities, relatively poor cycle lives, moderate round-trip efficiencies, very low costs, and low maintenance requirements. Lead-acid batteries are very safe and highly reliable, which in the past has made them quite popular for UPS and backup power supply applications.

[6] The term stationary is used to denote energy storage systems not contained in an electric vehicle.
[7] See for instance New York's *Energy Storage System Permitting and Interconnection Process Guide For New York City Lithium-Ion Outdoor Systems* (Chapter 7) and the national code NFPA 855 (Appendix A).

Nickel-based batteries are often used in portable applications such as power tools but have seen limited power sector deployment. These battery chemistries tend to have low energy densities, low power densities, moderate cycle lives, poor roundtrip efficiencies, moderate costs, and moderate maintenance requirements. Nickel batteries can handle wide ranges of discharging and loading and can be rapidly charged, making them one of the most durable battery chemistries. Finally, some types of nickel batteries (e.g., Nickel-Cadmium) have significant environmental concerns, given their utilization of toxic elements. These batteries also exhibit a memory effect, in which recharging the battery when it is not fully discharged permanently reduces the battery's capacity. The combination of the memory effect, poor power and energy densities, and environmental concerns has limited this chemistry's deployment in power sector applications.

Sodium-based batteries are primarily deployed for utility-scale applications in the power sector. These batteries are characterized by high energy densities, high power densities, high cycle lives, high roundtrip efficiencies, lower costs (particularly at larger scales), and low maintenance requirements, compared to other battery chemistries. These chemistries require high temperatures (in excess of 300°C) to operate and have stringent housing requirements given the extremely high reactivity and corrosiveness of some of their elements. These chemistries are made from readily available, inexpensive materials which may improve their economics relative to chemistries with rare element requirements, such as some lithium-ion chemistries. Stringent housing and operating temperature requirements make this chemistry unsuitable for most behind-the-meter applications.

Flow batteries are a relatively new battery chemistry well-suited to large-scale and long-duration applications. These batteries have poor energy and power densities, very high cycle lives, low to moderate roundtrip efficiencies, moderate costs, and relatively low maintenance requirements (primarily for associated pumps). These batteries are very safe and are not prone to fires or other hazards. Furthermore, the power and energy capacities of these batteries are easily and independently tunable, making them a very flexible option from a design standpoint. Given these systems' low energy and power densities and higher relative costs, flow batteries will likely experience limited use in behind-the-meter applications in the near-term, where size constraints are more relevant.

1.2.2 The Emergence of Lithium-Ion Batteries

The deployment of battery storage systems for front-of-the-meter applications in the United States has been dominated in recent years by lithium-ion chemistries, which represent over 97% of utility-scale battery storage installations by capacity (MW) since 2015 (EIA 2018). The growth of lithium-ion in energy storage applications is due to steep price declines caused by technological innovation and expanded manufacturing capacity. Manufacturing capacity is expected to continue to grow to serve growing demand from the transportation and power sectors and has been forecasted to reach a global annual manufacturing capacity of over 1,000 gigawatt hours (GWh) by 2025, up from 119 GWh in 2017, an increase of over 740%.

From 2010-2018, average lithium-ion battery pack prices declined from $1,160/kWh to $176/kWh,[8] a reduction of over 80%, with significant continued price declines predicted for the coming decade (see Curry 2017; BNEF 2019). Figure 2 shows global average lithium-ion battery price declines since 2010.

[8] In this report, unless otherwise noted, $ shall refer to USD.

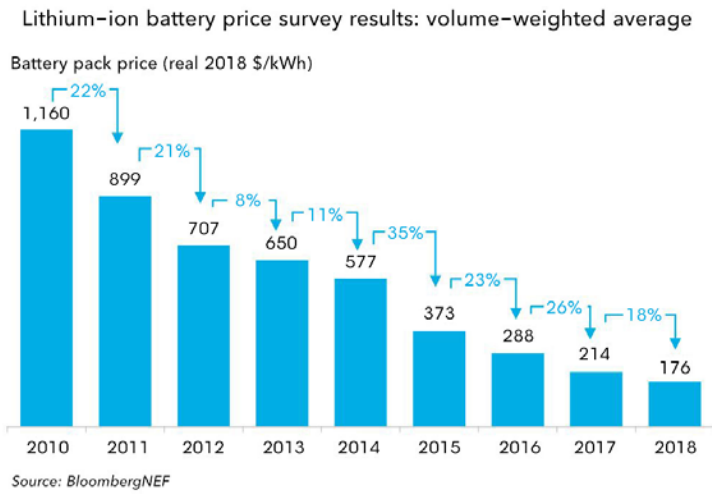

Figure 2. Average global lithium-ion battery pack price declines, including year-over-year percentage cost declines

Source: BNEF 2019

To date, utility-scale lithium-ion batteries in the United States have been predominantly used for the provision of operating reserves (i.e., the balancing of electricity supply and demand to maintain the appropriate power system frequency). In 2017, over 45% of lithium-ion utility-scale storage systems by power capacity (MW) provided frequency regulation (EIA 2018). Increasingly, utility-scale lithium-ion batteries are growing cost-competitive with conventional peaking capacity. As battery costs decline and variable renewable energy penetrations grow in the near future, there will be an increasing number of opportunities for utility-scale storage to provide peaking services (Denholm and Margolis 2018). Furthermore, cost declines and changing market dynamics are pushing increased average durations for both front-of-the-meter and behind-the-meter battery installations (GTM and Energy Storage Association 2019).

For behind-the-meter applications, lithium-ion chemistries have been even more dominant due to a number of considerations. First, battery cells and packs are modular, and behind-the-meter projects tend to benefit from the same price reductions due to manufacturing economies of scale as larger utility-scale systems. Second, many of the alternative storage options are simply not practical for behind-the-meter applications, due to aspects such as size (i.e., flow batteries) or safety considerations (i.e., sodium-based batteries). Third, lithium-ion batteries offer a higher relative energy density and durability, as well as faster charging times, relative to other battery chemistries that may otherwise be suitable for behind the-meter applications.

1.3 Battery Services, Value Streams, and Value Stacking

Batteries are a unique power system asset in that they can provide a highly diverse range of system services, spanning ultra-short-term timescales (i.e., subseconds to seconds) to medium-term timescales (i.e., hours to days). While other conventional resources can also provide these services, battery storage systems tend to do so more quickly and accurately, improving their potential contribution to power system reliability and flexibility. In many contexts, the scalable nature of batteries combined with their lack of point-source emissions makes it significantly easier to site these systems closer to demand relative to larger, conventional generators.

Figure 3 depicts the various system services that batteries can provide, as well as a color-coded indication of whether these services are commonly valued and monetizable in power systems around the world. The left side of each bar depicts the required response time of the battery for each service, whereas the right side of the bar depicts the maximum duration of time for which the storage resource typically must provide the service. Notably, the figure also depicts services these battery systems can provide based on where the battery is interconnected to the power system (i.e., behind-the-meter, distribution system, or transmission system). Batteries generally do not provide system services to segments of the power system with lower voltage levels than they are connected to but can provide services to higher voltage levels. For instance, a battery located on the distribution system can provide services to the distribution and transmission network, but not to individual customers for demand charge reductions. Batteries located behind-the-meter of a retail customer, on the other hand, are technically capable of providing all services across all voltage levels. It should be noted that the figure only illustrates what services batteries would be technically capable of supplying; however, the effective provision of these services by behind-the-meter battery systems in particular will require both enabling communication technology and mechanisms to adequately compensate battery system owners or operators for services provided (see text box: *Market and Policy Barriers to Value Stacking* in Section 8 for more information on nontechnical barriers to DPV-plus-storage systems providing system services).

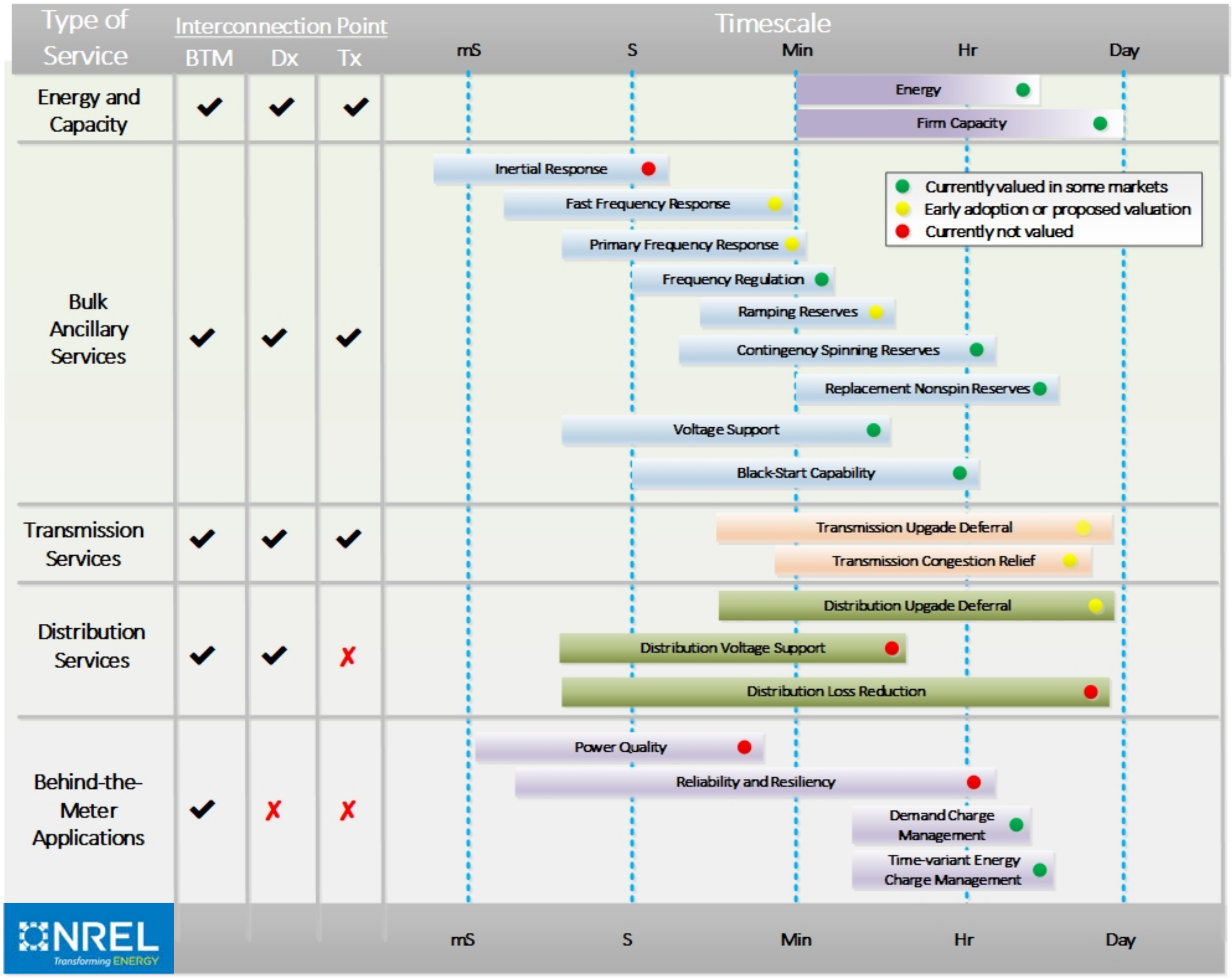

Figure 3: Summary of potential battery energy storage services and required response times and durations

Source: Original [*Illustration by Vahan Gevorgian, Paul Denholm & Owen Zinaman, NREL]*

Importantly, battery storage systems can have enhanced value to the power system and system owners by providing one and sometimes multiple distinct system services. As some services are often only needed infrequently throughout the year (such as black start and backup power) or only briefly throughout the day (such as frequency response), battery system operators can increase the utilization of their systems by providing distinct system services valued in the market for distinct durations at different times of day. This multi-use approach is known as “value stacking” and is increasingly being explored and implemented for grid-interconnected batteries, particularly in markets that offer more than one way to be paid for those system benefits. Value stacking can be an essential strategy for battery storage system owners, as monetizing multiple system services can improve battery economics (Bowen et al., 2019).

Although battery systems in general may be technically capable of providing multiple services, there are several important limitations to consider as regulators seek to facilitate the ability of behind-the-meter DPV-plus-storage customers to pursue value stacking activities. To begin, not all services that batteries are technically capable of providing are necessarily (or adequately) compensated, depending on the specific power system context, regulatory framework and location and interconnection voltage of the battery. Second, given that many of the services that batteries can provide require very different operating characteristics (e.g., duration and depth of discharge, response time), optimizing a battery system's technical performance for any single application, or even groups of applications may require excluding that battery system from effectively providing other groups of services. Even in the event that a range of services could theoretically be monetized, in practice it may be difficult for a battery to operate in an optimized manner to maximize its value to the system owner as well as the broader power system as the provision of one particular service may preclude the provision of others. For instance, if a battery commits to providing essential reliability services for a period of time (e.g., spinning reserves for a 3-hour period), in practice it may be impeded from other profit-seeking activities during that period (e.g., provision of energy following an unexpected wholesale market price spike). Furthermore, for smaller behind-the-meter systems, control algorithms are not yet widely available to allow customers to program or optimize batteries to take advantage of multiple value streams. Finally, as batteries provide an increased number of services, it is possible they will cycle more frequently than if optimizing their operations to provide a narrower set of services. Depending on the particular battery chemistry, this increased cycling could lead to an accelerated degradation of various battery performance metrics—thus, there may be additional operational costs associated with some value stacking activities that must be weighed against the benefits (Bowen et al., 2019).

The following section provides context into the United States and global storage market for both front-of-the-meter and behind-the-meter applications.

1.4 Storage Market Context: United States and Global

The emergence of distributed energy resources (DERs) is reshaping the traditional power sector paradigm in many U.S. states. As distributed solar deployment increases globally, a similar uptake in distributed storage is not far behind. Between Q1-2013 and Q1-2019, the U.S. storage market[9] grew by 1,252.7 MW[10] of deployed capacity, dominated by front-of-the meter systems, but with notable residential and nonresidential (behind-the meter) additions in more recent quarters. Of the systems installed between Q1-2013 and Q1-2019, 95.8% of the capacity of systems were of a lithium-ion chemistry type. The growth in capacity of these systems shows no signs of slowing down, with an estimated 16.9 GW of forecasted capacity additions from 2020-2024. The behind-the-meter market segment dominates in terms of number of annual and cumulative systems deployed, with an exponential uptick in behind-the-meter deployments observed since 2017 (Figure 4)(GTM 2019).

[9] Defined by Mackenzie Wood as "Electrochemical (batteries) and electromechanical technologies, excluding pumped hydropower, are included in the historical deployment and forecast data." (GTM 2019).
[10] Assuming no retirements between 2013-2018.

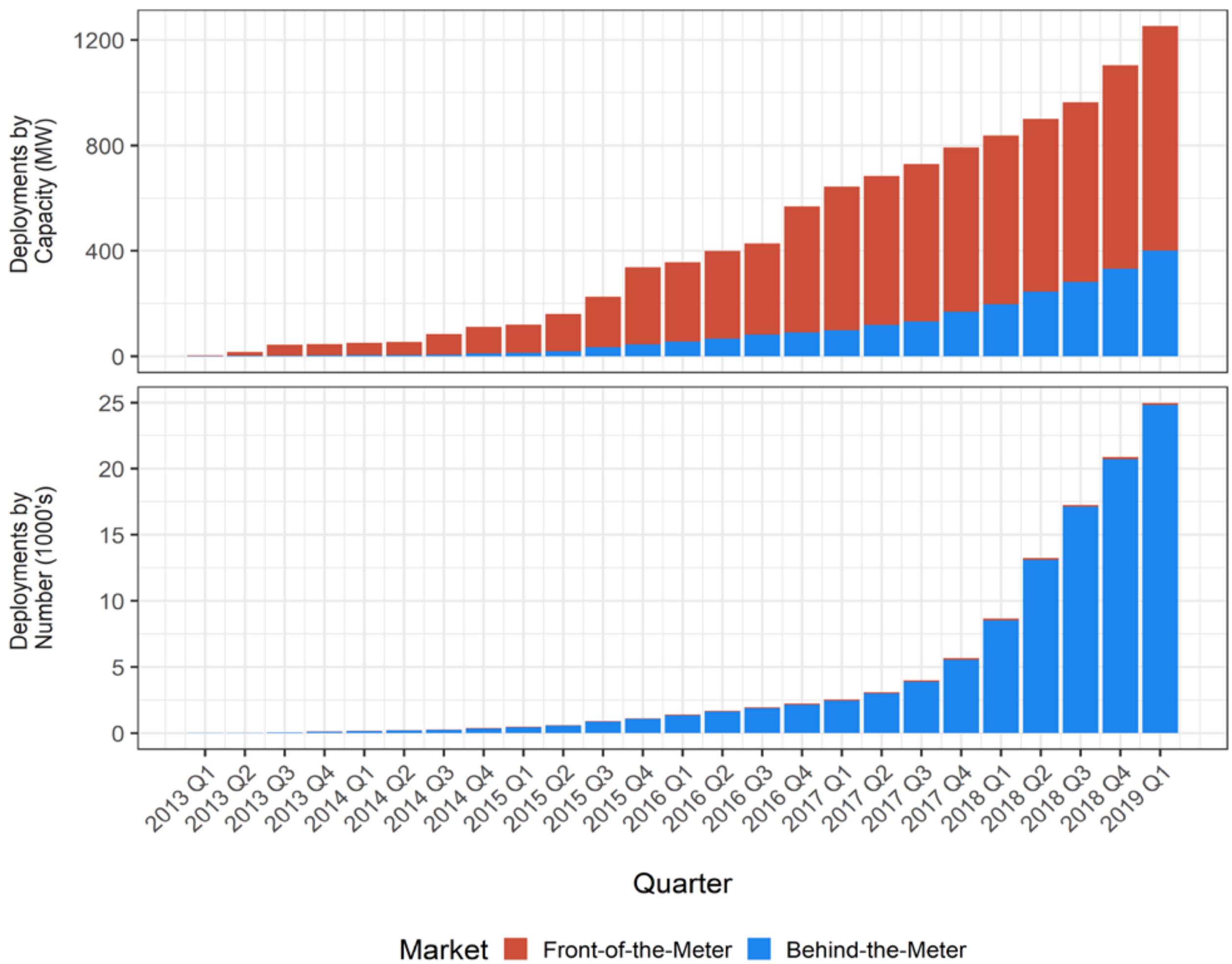

Figure 4. Cumulative U.S. deployment of energy storage by capacity and number of systems for front-of-the-meter and behind-the-meter systems from Q1 2013 to Q1 2019

Source: GTM 2019

The key drivers of residential and commercial behind-the-meter storage deployment include increasing customer interest in self-consumption of distributed generation and resilience, metering and billing arrangements,[11] and retail tariff design changes, such as net energy metering (NEM) and time-of-use (TOU) rates, that help to drive customer bill savings, grid service opportunities, policy and regulatory mandates and incentives, and system cost reductions (GTM 2019). The U.S. context is extremely diverse with respect to these drivers, as well as market organization (ranging from fully deregulated retail and wholesale power markets in Texas to vertically integrated utilities in Hawaii) and state and local policy priorities (with several states having targets for storage deployment and/or 100% clean energy targets). This wide range in drivers and approaches to integrating and incentivizing storage assets has led to a diversity of deployment results across states, with behind-the-meter storage systems more concentrated than front-of-the-meter installations (Figure 5). California and Hawaii have emerged as perhaps the most vibrant markets for behind-the-meter storage adoption, with both jurisdictions seeing significant deployment of both DPV and DPV-plus-storage systems. The diversity of state actions and levels of deployment in the United States provides a nearly comprehensive study of the variety of means available to utilities and policymakers to incentivize and integrate storage and DPV-plus-storage systems.

[11] Metering and billing arrangements define how consumption and generation-related electricity flows are measured and credited, and include strategies such as NEM, net billing, and buy-all, sell-all. This will be discussed in more detail in Section 4.

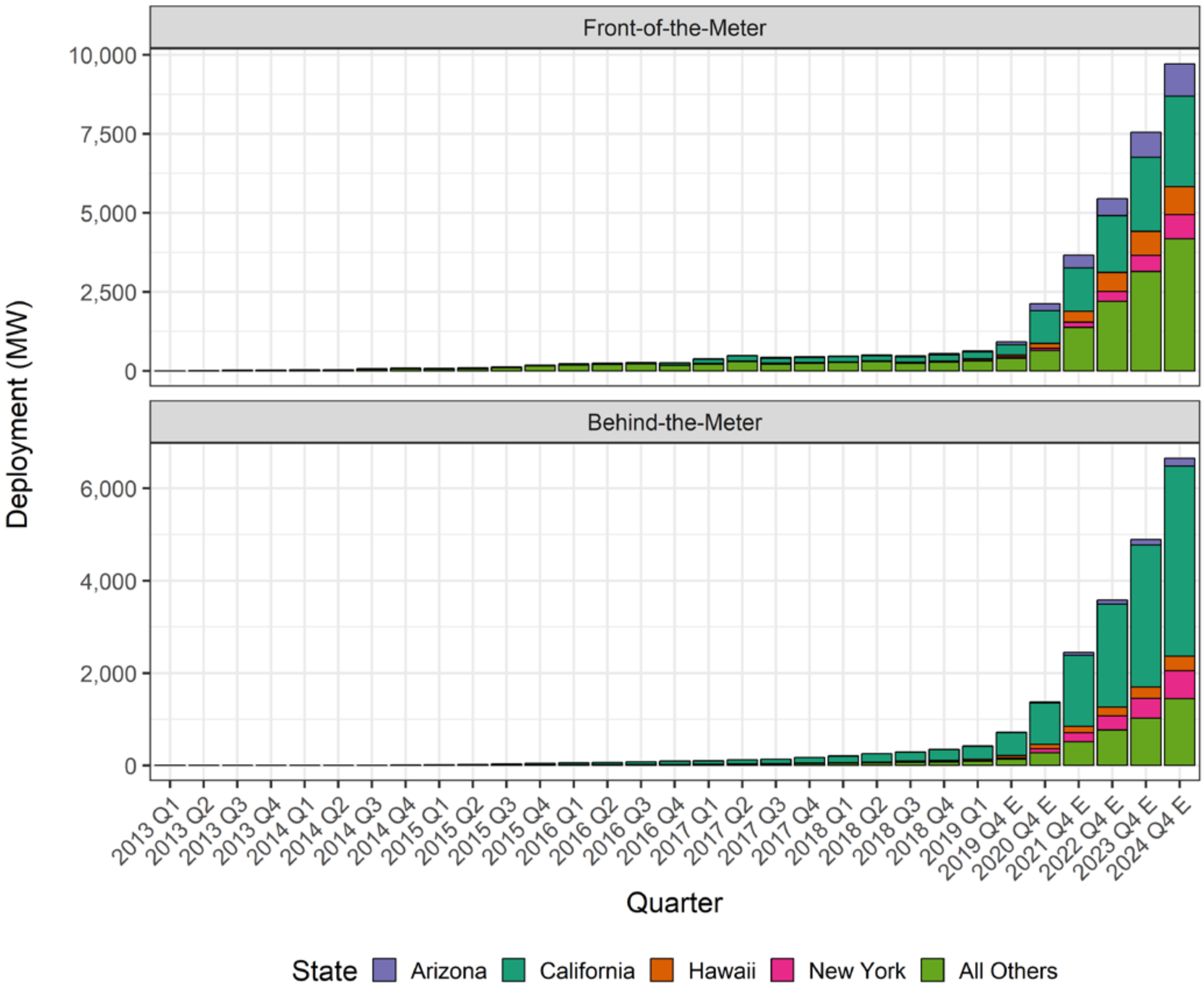

Figure 5. U.S. state deployment of energy storage by capacity of behind-the-meter and front-of-the-meter systems, historical and projected

Source: GTM 2019

Around the world, growth in behind-the-meter storage deployment is catalyzed by clean energy and climate goals, interest in resilience and backup power, and further reductions in storage costs, among other factors. By 2026, Navigant estimates that the annual global market for distributed storage energy systems[12] will reach 27.4 GW, led by the Asia Pacific and Western Europe regions (Figure 6) (Tokash and Dehamma 2017).

[12] Accounting for both distributed-grid-tied and off-grid systems.

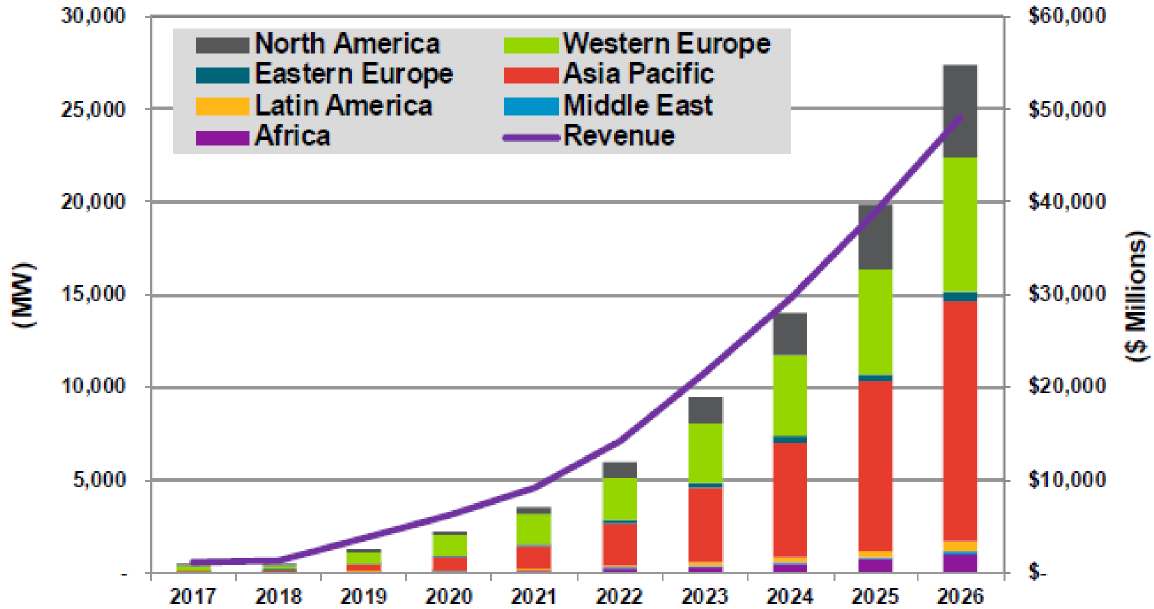

Figure 6. Estimated annual distributed grid and off-grid PV-plus-storage power capacity and expected vendor revenue by region, world markets: 2017-2026

Source: Tokash and Dehamma 2017

2 Approaching DPV-Plus-Storage Regulatory Design

2.1 The Regulatory Design Process

At a high level, designing a regulatory framework that aligns DPV-plus-storage deployment with larger policy objectives requires thoughtful deliberation across a range of technical and economic issues. While this report attempts to segment many of these issues into distinct topics to enhance reader understanding, in reality, DPV-plus-storage regulatory issues are all closely integrated, and design decisions on a single aspect often have broader implications.

In that context, Figure 7 presents a high-level process for how regulators can sequentially approach the design of DPV-plus-storage regulatory frameworks. As a first step, developing clear regulatory objectives—which may be influenced by, aligned with, or directly derived from stated public policy goals—can help guide individual decisions on designing regulations (Section 3). Next, regulators can consider the appropriate compensation mechanism offerings for DPV-plus-storage systems that attempts to address and balance objectives related to fair customer compensation and utility cost recovery, as well as the desired role of DPV-plus-storage in the power system (Section 4). Thereafter, rules governing the metering and technical configuration requirements can be designed to ensure the desired compensation mechanism can be implemented (Section 5). Then, the overarching interconnection process can be designed to offer a safe and orderly procedure for DPV-plus-storage systems to apply for interconnection, as well as to provide technical guidance to installers on the various regulatory requirements that must be complied with (Section 6). Next, regulators may need to consider and account for local permitting requirements (and associated safety codes) that must be complied with to deploy behind-the-meter storage systems (Section 7). Finally, because all regulatory processes exist within a broader policy and market context, common policy and market instruments and approaches related to DPV-plus-storage are discussed briefly in Section 8. Importantly, steps can also interact in other ways. For example, compensation mechanisms can be designed to accommodate existing metering configurations. After the steps in the regulatory design process for DPV-plus-storage (Figure 7) are discussed in detail, Section 9 offers a summary of key regulatory considerations for DPV-plus-storage systems.

Figure 7. Approaching regulatory design for DPV-plus-storage systems

Source: Original [*Illustration by Christopher Schwing, NREL]*

2.2 Customization Dimensions for Regulatory Design

Similar to grid-tied distributed generation systems without storage, it may be worthwhile for regulators to consider implementing distinct compensation mechanisms and technical requirements for different segments of the retail customer base to better balance various regulatory objectives. For instance, it is common in clean distributed generation programs to offer more generous compensation levels with less rigorous metering requirements for smaller capacity DPV systems and/or residential customers to improve the economics of smaller-scale systems with a lower magnitude of technical and financial impacts on the utility system at lower deployment levels.

The various customization dimensions detailed in Table 2 are not mutually exclusive and can be implemented in parallel as deemed appropriate by the regulator for distinct DPV-plus-storage compensation mechanism offerings and associated metering and technical configuration requirements.

Table 2. Customization Dimensions for Regulatory Design

Dimension	Description
Customer Class	Offering distinct compensation mechanisms to customers, using distinct retail tariffs may be an effective strategy for balancing utility and customer interests in a more customized manner, as customers with distinct retail tariffs have accordingly distinct financial impacts on utilities.
Voltage Interconnection Level	Implementing distinct metering, technical configuration, or interconnection requirements for system connecting to the network at distinct voltage levels may be an effective strategy to ensure that requirements are designed with an appropriate level of rigor for the expected impacts and potential service offerings of the DPV-plus-storage system.
System Capacity	System capacity can be based on the capacity of the DPV system, the storage system output, the combined capacity of both systems, or the maximum output from the system the grid will see based on limitations imposed on the system (e.g., inverter software that limits the maximum output). Offering distinct requirements based on system capacity can be useful for delineating both compensation levels and grid requirements, with larger systems typically being subject to a more rigorous review process.
Consumption Magnitude	A monthly or annual consumption segmentation is also possible, using historical consumer consumption data to calculate a rolling average metric for kWh usage, offering distinct compensation mechanisms for various tiers of consumption. This approach might be useful should there be a desire to offer more generous compensation to lower consumption customers, as the magnitude of their expected utility financial impact would be smaller due to their lower overall energy needs.
Geography	Different regions or service territories within a country may have distinct technical or economic considerations that merit different approaches to regulation. For instance, geographically remote and/or off-grid systems may merit separate regulatory treatment compared to customers in urban centers.
Local Grid Characteristics	The characteristics of the local distribution system where a system may be deployed could merit a customized approach to creating regulatory requirements and compensation mechanisms for DPV-plus-storage systems. For example, in areas with distribution feeders that regularly experience power quality issues, certain technical configuration requirements and compensation mechanisms may be appropriate to ensure that batteries can provide power quality services and receive a fair compensation for doing so. This approach may be good practice to support efficient technical integration of DPV-plus-storage resources, but also requires extremely clear technical criteria and a predictable process to regularly update regulatory requirements for newly interconnecting resources.

2.3 Other Relevant Regulatory Tools

2.3.1 Deployment Caps and Tools

Program caps are limits on the total capacity or number of systems eligible for a DER program, or can be stated as a total budget allotted for a DER program, regardless of any individual system's size, and can be an important tool in the development and deployment of rebate and financial incentive programs, and even compensation mechanisms and tariff offerings. Program caps are a simple but effective tool to ensure cost containment for utilities administering the program, as well as to limit the impact such DPV-plus-storage systems may have on a utility's revenue, or on the level of cross-subsidization borne by nonparticipating customers. These caps can be differentiated among subregions or staggered across periods of time. Program caps can be calculated in a number of ways, including as an absolute capacity limit or as a percentage of peak demand. Program caps can also be used to trigger changes in the program, and in some jurisdictions in the United States, program caps are used to initiate proceedings to reevaluate incentive programs and compensation mechanisms (NREL 2019). Most often these caps are established upfront to clearly state program goals, and they can be adjusted over time as different deployment caps are met.

Deployment-based payment adjustments are a means to adjust compensation mechanism offerings as cumulative deployment of a DER technology increases and have been commonly used in the context of DPV. As opposed to a program cap, which more plainly sets a ceiling for deployment levels, cumulative deployment ratchets might reduce the DPV-plus-storage sell rate or make adjustments to retail tariffs once certain deployment levels are achieved. For instance, Germany's feed-in tariff program set a predetermined schedule for how the sell rate[13] for DPV-plus-storage would decrease as cumulative deployment increased (Bundesnetzagentur 2019). In Israel, the regulator implemented a new tariff component on retail customers once cumulative solar capacity (including both utility-scale and distributed resources) in the country achieved 1.8 GW of deployment to reflect growing grid integration costs (PUA 2014).

System size caps are absolute limits on the size of individual distributed generation (DG) or storage systems, and are typically stated in terms of capacity (e.g., kW or MW) or an annual ratio of DG production to customer load (known colloquially as the PV-to-Load ratio). Capacity-based caps tend to be implemented to limit compensation mechanism eligibility (e.g., NEM is only available for systems under 100 kW) and to ensure that interconnection requirements are appropriately rigorous given the size of the system (e.g., systems under 10 kW are granted a fast-track screening process). System size caps based on the PV-to-Load ratio tend to be implemented to encourage self-consumption behavior (as opposed to utilizing DPV-plus-storage customers as grid-interactive resources). As mentioned in the previous section, system size caps are a useful tool for segmenting the retail customer base to offer customized compensation mechanisms and interconnection requirements.

2.3.2 Alternative Ratemaking Paradigms

Revenue decoupling is a regulatory strategy to address utility disincentives to support energy efficiency and distributed energy resource programs which reduce utility sales. Specifically, regulators sever the connection between utility revenues and the volume of retail electricity sales. Tariffs are instead designed to ensure that utility will earn sufficient revenue to cover network and energy procurement costs. Revenue decoupling is a substantial departure from traditional cost-of-service regulatory approaches and is not a decision to be taken lightly. This topic has been discussed at length in the literature—see e.g., Lazar et al. (2016).

Performance-based regulation represents another significant shift in utility regulation and ratemaking. Performance-based regulation provides a framework to: (1) set utility goals and targets; (2) measure utility performance in achieving these goals and targets; and (3) link utility performance to utility compensation, including investor returns and executive compensation. By setting predetermined metrics for performance, regulators can create financial incentives for activities that utilities might not normally be motivated to pursue, such as the streamlining the interconnection of DPV-plus-storage resources. Similar to revenue decoupling, shifting toward the use of utility performance incentive mechanisms is a significant change. While quite relevant for more advanced jurisdictions facing large quantities of distributed energy resources, it is outside the scope of this report.[14]

[13] We define a sell rate as the level of compensation a DG system owner receives for electricity exported from the DG system to the grid.

[14] For more information on performance based regulation for utility regulation and ratemaking, see Littell et al. (2017) and Whited, Woolf, and Napoleon (2015).

3 Step I: Develop and Prioritize Regulatory Objectives

DPV-plus-storage may inform or be the target of a diverse range of underlying regulatory objectives. These objectives influence design decisions pertaining to compensation mechanisms, metering requirements, technical configuration requirements, and interconnection processes. Thus, developing a set of clearly articulated regulatory objectives can serve as a useful first step for regulators. Importantly, most objectives are neither mutually exclusive nor binary; however, some objectives may conflict with others. Facilitating upfront dialogue to help weigh, balance, and prioritize objectives can facilitate faster decision-making. Potential objectives for DPV-plus-storage programs are presented below.

3.1 Approach to DPV-Plus-Storage Market

Depending on the relevant set of statutory mandates, policy guidance, and/or legal authorization that a regulatory agency has, regulators may exhibit a range of perspectives toward DPV-plus-storage programs. These might include[15]:

- **Constrain DPV-plus-storage deployment**—Some regulators may be unfamiliar or concerned about DPV and DPV-plus-storage systems and may wish to constrain deployment through direct actions or deliberate inaction.
- **Enable DPV-plus-storage deployment**—Most regulators are typically mandated with an enabling role for DER programs that focuses on motivating the utility to facilitate a safe and orderly interconnection process, while also preserving fairness among participating and nonparticipating customers and preserving utility revenue sufficiency.
- **Accelerate DPV-plus-storage deployment**—Some regulators with more ambitious mandates or specific objectives in mind for the desired role of DPV-plus-storage may wish to see utilities play a role in accelerating the development of the DPV-plus-storage market.

3.2 Desired Role of DPV-Plus-Storage Systems

DPV-plus-storage systems can play a variety of roles in power systems, from exclusively serving customer needs, to being fully grid-interactive assets that provide a range of services to the distribution and/or transmission system, with many options in between.

- **Encourage self-consumption for DPV-plus-storage systems**—Regulators may wish to see DPV-plus-storage systems deployed to primarily or explicitly serve a customer's own energy demand, and/or for backup purposes during grid outages. They may also wish to reduce the likelihood or scale of net exports to the grid and/or mitigate major peaks in grid injection and withdrawal, which can cause challenges for certain utilities and their power systems. In practice, encouraging self-consumption for DPV-plus-storage systems may mean discouraging the over-dimensioning[16] of storage and/or DPV assets through specific regulations. At a high level, an objective to encourage self-consumption from DPV-plus-storage systems will have implications for the technical configuration requirements of systems and may prove consequential for the future ability of DPV-plus-storage systems to become grid-interactive.
- **Utilize DPV-plus-storage to manage system peaks—**Regulators may be particularly interested in enrolling DPV-plus-storage customers to manage system peaks, particularly in regions or on specific feeders that regularly experience steep ramps in net load and/or load shedding. This can be enabled through retail tariff design that encourages reductions in grid consumption and/or grid injections during times of peak demand, as well as demand response programs that rely on customer-sited storage. Utilizing DPV-plus-storage to manage system peaks is a commonly discussed form of grid interactivity.
- **Enable full grid interactivity of DPV-plus-storage systems**—Regulators may wish to enable and/or preserve the option for DPV-plus-storage systems to provide a range of valuable grid services to the power system. Such grid interactivity could be as simple as allowing DPV-plus-storage customers to participate in energy arbitrage activities, such as by reducing demand, or increasing DPV-plus-storage exports during peak

[15] This framing of approaches to storage-plus-DPV loosely follows that provided in (Rickerson et al. 2014).

[16] "Over-dimensioning" refers to the oversizing of DG (and storage) systems relative to the energy needs of the individual customer. This is particularly a concern in settings which offer more generous compensation rates for clean distributed generation.

demand periods in response to TOU price signals (see previous objective). It could also involve the provision of a range of other services (e.g., congestion management, frequency regulation), enabled through "virtual power plants," where third-party aggregators sell grid services from multiple distributed systems directly to distribution companies and/or on wholesale power markets. Encouraging grid interactivity can spur the deployment of DPV-plus-storage systems by increasing the value streams available to them, while helping to contribute to power system operations by aligning individual customer behavior with the broader needs of the power system. In any case, the extent of desired grid interactivity has significant implications for a wide range of regulatory decisions, including those relating to compensation mechanism design, metering, as well as technical configurations. In particular, decisions related to whether or not the storage system should be allowed to charge from and export to the power system have important implications for DPV-plus-storage grid interactivity objectives.

3.3 Fairness and Equity Considerations

Regulators may be presented with various fairness and equity considerations as they deliberate regulatory design options. Some common objectives pertaining to fairness and equity include:

- **Balance the financial interests of utilities, DPV-plus-storage customers, and nonparticipating customers**—Similar to dialogues surrounding DPV, regulators designing DPV-plus-storage programs typically attempt to balance the financial interests of utilities, adopting customers, and nonadopting customers, while attempting to not upset existing balances of cross-subsidization between customer classes. In practice, this means regulators must deliberate how to ensure that utilities' fixed costs continue to be adequately recovered through electricity sales, even as these sales are reduced through DPV-plus-storage, as well as through customer self-consumption occurring under any self-supply scheme. Regulators must also consider how to protect nonadopting customers from cost-shifting if utilities are granted retail tariff increases to recover lost revenue due to DPV-plus-storage deployment. The balance that regulators ultimately strike will have implications for compensation mechanism design, and in particular the design of retail tariffs and metering and billing arrangements. Related to this objective, regulators may also wish to reduce the likelihood of customers deciding to become entirely self-reliant and disconnecting from the grid[17] through providing more attractive compensation mechanisms or implementing certain technical configuration requirements which encourage the enrollment of DPV-plus-storage customers as grid resources.
- **Create fair and reasonable metering and interconnection requirements for customers and utilities**—Complying with metering and interconnection requirements typically comes at an incremental cost that is typically born by DPV-plus-storage customers. As these incremental costs can reduce the economic viability of DPV-plus-storage systems, regulators can help to ensure that they are of an appropriate scale relative to the overall system's cost. Furthermore, in the event that regulators are attempting to mitigate a particular undesired behavior with additional metering infrastructure (e.g., energy arbitrage activities using the storage device), they might aim to ensure that the cost and/or administrative burdens associated with these requirements are commensurate with the scale of problem they are trying to mitigate, so as to not enforce an undue burden on DPV-plus-storage customers.
- **Preserve the integrity of DPV compensation mechanisms**—Compensation mechanisms have historically been implemented to reward exported energy that is generated from eligible DG systems (e.g., DPV). Some regulators may wish to place an increased emphasis on ensuring that grid-supplied energy later exported by the storage system does not yield a financial reward that is intended for clean DG.[18] The extent of a regulator's emphasis on this goal will influence decisions surrounding compensation mechanism design, metering, and technical configurations.

3.4 Program Administration

Regulators, along with utilities, may be interested in ensuring that program administration tasks are not overly cumbersome or expensive for utilities and customers. Some common objectives in this realm include:

[17] In this realm the terms 'grid defection' and 'load defection' are commonly invoked to describe the process of customers choosing to meet the entirety or majority of their energy demand through on-site DERs such as rooftop solar and behind-the-meter storage for primarily financial reasons. Of course, in countries with highly unreliable grids, customers may have little choice but to use other means for their energy needs.

[18] Importantly, such customer behavior could ultimately be quite desirable to regulators depending on the specifics of their power system.

- **Reduce administrative requirements for utilities**—The implementation of DPV-plus-storage programs may drive new administrative requirements for utilities, in particular associated with processing interconnection applications and implementing new billing procedures. Different approaches to designing interconnection processes or metering requirements may have implications for the administrative workload for utilities. For instance, encouraging utilities to transition to standardized online portals for processing interconnection applications can drastically reduce the amount of time and labor needed for each application compared to processing applications individually by hand (Peterson and Reiter 2017).
- **Avoid new requirements on existing systems**—Changing metering or other technical requirements after systems are already installed can be expensive and administratively burdensome. Regulators may wish to consider decisions surrounding metering requirements, technical configurations, and interconnection requirements in light of not only the current role of DPV-plus-storage systems on the power system, but also how that role may change over time, particularly if that future role may involve more grid interactivity. Along similar lines, regulators may wish to design rules such that existing regulations for grid-tied DPV systems also apply to DPV systems that are retrofitted with storage, which can reduce uncertainty and burdens for customers seeking to add storage to their existing DPV systems. Particularly in jurisdictions with large amounts of existing grid-tied DPV systems, creating clear and streamlined "on-ramps" for customers adding storage to an existing DPV system may be an important regulatory consideration.

3.5 Transparency, Monitoring, and Safety

Regulators, along with utilities, may be interested in promoting additional visibility into the operation of DPV-plus-storage systems to support greater safety and reliability in the power system, policy compliance, and/or improved power sector planning exercises. This is typically achieved through the deployment of supplementary metering and information and communication technologies that collect, store, and transmit relevant real-time power system operational data, which comes at an additional cost to customers and/or utilities. Thus, the following objectives are often in tension with objectives to minimize unfair cost burdens.

- **Promote real-time intelligence and transparency—**Regulators may wish to ensure utilities have access to high quality operational data and/or the ability to remotely island DPV-plus-storage systems during outages. Having access to data about—and perhaps even remote control over—the DPV-plus-storage system can help ensure reliable service delivery by enhancing operational awareness on individual feeders of the distribution network, while reducing safety risks to utility line workers. This objective may influence decisions relating to communications and control requirements that are placed on DPV-plus-storage systems through metering configuration rules and interconnection requirements.
- **Track clean energy production**—For regulatory compliance with clean energy goals, such as mandates and Renewable Portfolio Standards (RPS) (see Section 4.3), some regulators may wish to have increased visibility into the production of the DPV component of the DPV-plus-storage system. This objective may influence metering requirement decisions.
- **Track users' gross electricity demand**—Understanding a customer's electricity demand patterns independently of the DPV-plus-storage system can help inform utility planning and operations and may be a stated objective for regulators and/or utilities. Like the previous objective, this may influence metering requirement decisions.

4 Step II: Design Compensation Mechanism

Compensation mechanisms broadly determine both how energy flows are both metered and rewarded. In general, compensation mechanism design decisions have broad implications, spanning the deployment and operational behavior of DG assets, customer bills, and utility revenue collection, as well as metering setups, system technical configuration requirements, and interconnection processes. Compensation mechanisms for DPV-plus-storage comprise the same three basic elements as other DG (Zinaman et al. 2017):

1. **Metering and billing arrangements**—The first aspect defines how consumption and generation-related electricity flows are measured and credited;
2. **Retail tariff design**—This aspect defines the retail tariff structure and exact purchase rate the DG system owner must pay for electricity from the grid, and thus helps defines the potential for customer bill savings; and
3. **Sell rate design—**The final element defines the exact level of compensation a DG system owner receives for electricity exported from the DG system to the grid.[19]

While compensation mechanism for DPV-plus-storage and other DG share a similar set of implications, there are some important key differences to consider, which are detailed throughout this section.

The subsections below will review the following aspects of DPV-plus-storage compensation mechanism design and implementation:

1. *Section 4.1—Metering and Billing Arrangements*, with a focus on NEM and net billing schemes for DPV-plus-storage customers;
2. *Section 4.2—Retail Tariff Design*, with a discussion on how various retail tariff elements incentivize certain behaviors from the system owner and how these elements influence the relative economics for DPV-plus-storage systems versus grid-tied DPV systems; and
3. *Section 4.3—Sell Rate Design*, with a brief discussion on how the level of compensation a system receives for energy exports can impact system economics.

It is important to note that although these issues are represented here as distinct topics, in reality they are all closely integrated with one another and cannot be considered in isolation. They have been separated in this report to enhance reader understanding, but the relations between the issues will be discussed throughout the various sections.

As well, regulatory objectives and market context often influence compensation mechanism design and its timing. Solar penetration levels, grid management issues, storage deployment mandates or goals (see Sections 8.1 and 8.2), DER technology costs, utility cost recovery and cross-subsidization considerations, and low-income customer concerns are examples of factors that may drive regulators to consider certain design choices at certain times over others. High penetrations of PV, for example, may create certain grid management issues (e.g., duck curve) that could motivate the utilization of more granular, cost-reflective rates (e.g., TOU tariffs) or alternatives to NEM to better align customer and grid system needs. On the other hand, jurisdictions that have financially insolvent utilities or significant cross-subsidy schemes in place may be more concerned with ensuring utility revenue sufficiency and avoiding cost-shifting and may wish to encourage the use of customer-sited storage deployment primarily for self-supply or backup during grid outages.

At a high level, changes in compensation mechanism design consequently drive customer behavior and may incentivize greater behind-the-meter storage deployment, depending on the specific approach taken. Early-stage DER markets may take different approaches to compensation mechanism design than mature DER markets depending on these context-specific factors and needs. In an era of rapidly shifting technology costs, customer

[19] For the purposes of this report, sell rate design refers specifically to the design of a volumetric energy export rate (i.e., stated in $/kWh) under a compensation mechanism framework designed for retail customers that is approved by regulators. In the future, this term could also be inclusive of compensation rates offered by aggregators and other third parties in the free market (i.e., not set by regulators) for grid services provided by customer-sited DER.

demand, and power system dynamics, the leapfrogging of traditional compensation mechanism design transition pathways forged by mature DER markets is entirely possible, if not likely.

4.1 Metering and Billing Arrangements

This section focuses on the two primary metering and billing arrangements for behind-the-meter resources that allow for self-consumption of on-site electricity production: net energy metering and net billing.[20]

4.1.1 Review of Net Energy Metering and Net Billing

Net energy metering (NEM), often referred to as net metering, is the most common compensation mechanism for DG in the United States. In NEM schemes, whenever a customer's distributed generation exceeds their consumption, their excess generation is injected to the grid for a credit in kWh. These credits can then be used to offset their consumption from the grid in the current billing cycle and often in future billing cycles, depending on the design of the specific NEM program. Thus, it is the customer's net consumption of energy from the grid, or the consumption from the grid minus the exports from the customer's distributed generation system, which is billed. This net consumption is typically measured using a single bidirectional net meter (see Figure 8). Gross metering, with separate consumption and generation meters, can also provide the same compensation as net metering, provided the sell rate for compensation of grid injections matches the volumetric portion of the retail electricity tariff, and the crediting terms[21] are sufficiently similar (Zinaman et al. 2017).

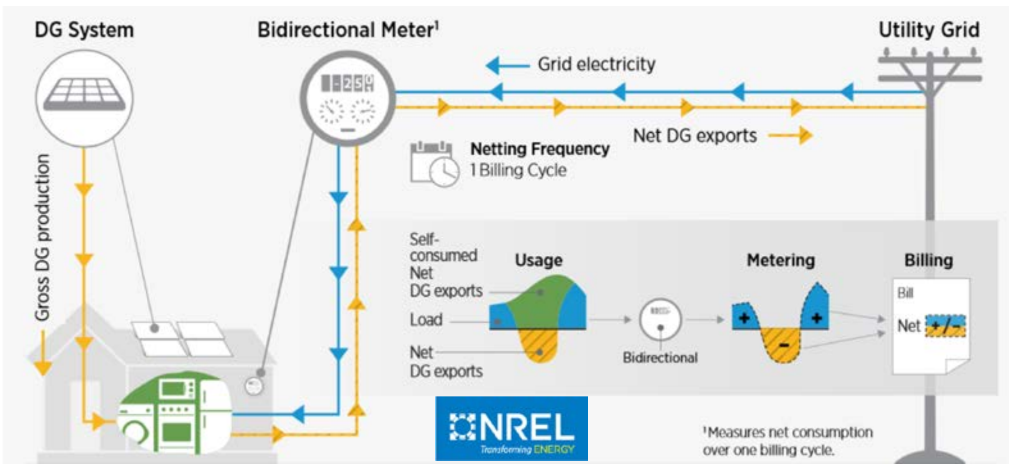

Figure 8. NEM schematic for DG system without BESS

Source: Adapted from Zinaman et al. 2017

Despite NEM's popularity in the United States, some jurisdictions have begun transitioning to net billing schemes. Under net billing, excess DG injected to the grid cannot be used to offset consumption on a kWh-for-kWh basis in later periods (as occurs under NEM), and instead is turned into bill credit. Any DG injected into the grid is credited at a predetermined sell rate (typically less than the volumetric retail energy tariff[22]). All injections to the grid are metered in real time by an electricity export meter. Any energy consumption from the grid (which, in practice, is the customer's real-time energy demand in excess of their real-time DG production) is charged to the customer at the predetermined volumetric retail energy tariff, as usual, using a regular electricity consumption meter. At the end of the billing cycle, the customer is charged for the difference between the generation credits and the consumption debits (see Figure 9) (Zinaman et al. 2017).

[20] Buy All, Sell All metering and billing arrangements are not discussed, as these are effectively front-of-the-meter schemes for retail customers.

[21] Crediting terms define whether compensation is granted as bill credit (either in currency or kilowatt-hours) or directly as cash payments. They also determine the extent to which credit can be carried over between billing cycles and the circumstances under which credits might expire and cash payments are paid to the DG system owner. For more information, see Zinaman et al. (2017).

[22] Sell rates for injections at levels above the volumetric energy charge of the retail tariff also occur in some places, but typically under buy-all sell-all or nonuser DPV schemes (IEA 2019).

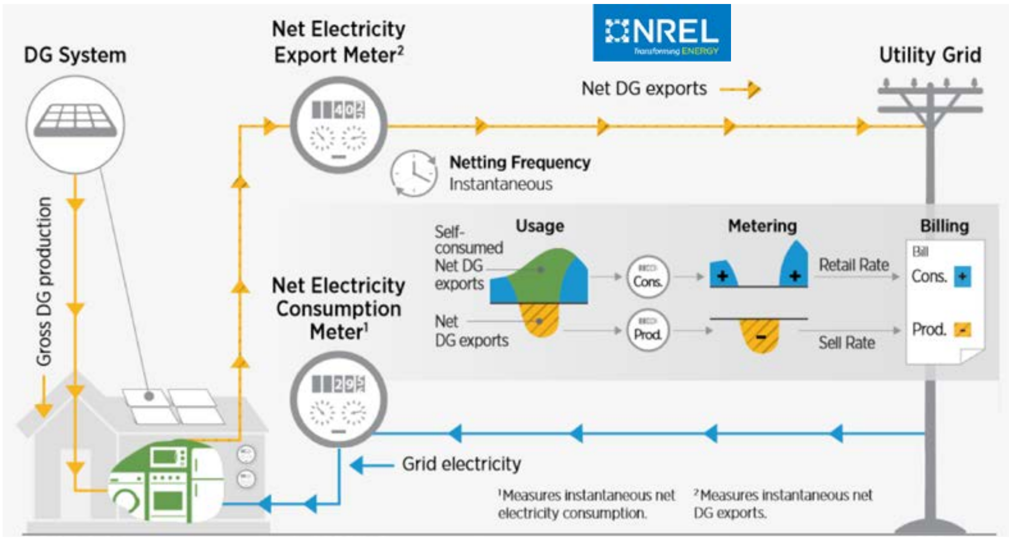

Figure 9. Net billing schematic for DG system without BESS

Source: Adapted from: Zinaman et al. 2017

4.1.2 Implications for DPV-Plus-Storage Deployment

NEM schemes essentially enable the utility grid to offer a form of financial storage for behind-the-meter DG systems. Whether it supports combined DPV-plus-storage systems depends on how regulations are structured.

- If the DPV-plus-storage customer is under an NEM scheme and is subject to a tariff structure that features a time-invariant volumetric energy rate, then from the customer's perspective, in financial terms, the utility distribution system serves the same function as the storage system—to bank DPV energy for that individual customer's benefit and use it at a later time. Thus, such a simple retail tariff structure under NEM does not incentivize the pairing of DPV systems with behind-the-meter storage. See Section 4.2.1.1 for a deeper discussion.
- TOU tariffs could be optimized to encourage DPV-plus-storage systems configured to export during higher value times (e.g., peak periods) NEM schemes under TOU energy rates—where distinctly valued kilowatt-hour credits are granted for exports based on the time of export—can help customers reduce bills and enhance the business case for DPV-plus-storage deployment. These are described more fully in Section 4.2.1.2.

Net billing schemes typically feature a sell rate for exports below the retail volumetric energy rate. As a result, customers have an economic incentive to maximize self-consumption of their DPV production, because avoiding a retail kilowatt-hour purchase from the grid through self-consumption is more valuable to the customer than receiving compensation for exports. But much of a customer's demand is typically noncoincident with times of DPV production; thus, the presence of a paired energy storage system for customers under net billing can augment the ability of the customer to self-consume their DPV kilowatt-hours, as DPV kilowatt-hours that would otherwise be exported can be stored and consumed at a later time, after accounting for roundtrip losses.

4.2 Retail Tariff Design

Because energy storage systems can enhance the ability of the customer to increase DPV self-consumption and avoid retail electricity purchases, the retail tariff structure tends to have a more significant effect on overall DPV-plus-storage customer economics than choosing between a NEM or net billing scheme (McLaren et al. 2019).

Retail tariff design is an essential element of compensation mechanisms for DPV-plus-storage systems. From a customer's standpoint, the bill savings and credits yielded from behind-the-meter systems are intrinsically linked to retail tariff design and, thus, retail tariffs strongly influence both customer economics and deployment. From a utility's perspective, retail tariff design can promote utility revenue sufficiency and help align customers' exports and consumption with the needs of the larger power system.

Importantly, many of the retail rate design strategies discussed in the following subsections that are intended to support DPV-plus-storage deployment involve the introduction of greater complexity to retail tariff structures.

This is predominantly implemented through time-variant rates, as well as demand-based charges, which are intended to better reflect the real-time cost of electricity delivery.[23]

More complex tariff structures may require more advanced metering solutions. In practice, these advanced tariff structures have been enabled by the emergence of advanced metering infrastructure, which is able to measure and collect more granular data on electricity production and consumption. Smart infrastructure, which intelligently operate behind-the-meter energy assets and manage energy consumption—such as battery control systems, home energy management systems, and smart thermostats—can also play a large role in enabling DPV-plus-storage customers facing more complex retail tariff structures to realize bill savings. These technologies can enable customers to increase their bill savings by shifting consumption from the grid to lower price periods (in response to time variant rates) or reduce peak demand (in response to demand charges) in an automated manner.

As utilities and regulators consider these strategies, some key practical considerations to keep in mind include[24]:

- **Simplicity**—Will the customer be able to understand how they are being charged for electricity under the new tariff? Will the utility be administratively and technologically prepared to implement the new tariff?
- **Responsiveness**—Does the customer have both the understanding and the ability to adjust their energy behavior to lower their bill under the new tariff?
- **Stability—**Is the customer (and utility) sufficiently shielded from unreasonably high fluctuations in bill costs (and bill collections) between billing cycles?

At a high level, many regulators and utilities are attempting to balance the above considerations with a desire to, among others:

1. better align customer operational behavior with the technical requirements of the power system;
2. promote fair utility cost recovery;
3. reduce cross-subsidization effects between participating and nonparticipating customers; and
4. promote the deployment of specific technologies to meet other policy objectives.

The subsequent subsections introduce various tariff structure elements and outline considerations for implementing them in the context of DPV-plus-storage deployment.[25]

4.2.1 Volumetric Energy Rates

Volumetric energy rates are a standard tariff component designed to charge customers on a per kilowatt-hour (i.e., $/kWh) basis for their electricity consumption. Essentially all retail electricity customers pay some form of volumetric energy charge, which often comprises the majority of customers' bills for residential customers. Commercial and industrial ratepayers typically also have volumetric energy components of their electricity bills, but may also have demand-based charges in their utility tariffs as well.[26] In the context of DPV-plus-storage systems, the following subsections will discuss:

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[23] Until recently, almost all residential customers and many smaller commercial customers around the world have been subject to tariffs comprising a simple, flat volumetric electricity rate that ensured steady revenues to utilities and stable, easily understood bills for customers. But with the advent of new metering and information and communication technologies, it is increasingly possible to institute more complex tariff elements normally reserved for large commercial and industrial customers, such as time-of-use rates and demand charges. These new tariff structures will be discussed in subsequent subsections.

[24] These considerations are not unique to DPV and storage-plus-DPV systems, but instead apply to all retail customers subject to tariff changes; however, the presence of a storage system presents new opportunities for customers to use battery control software to be more responsive to more complex tariffs.

[25] Fixed charges and minimum bills—which are often used to recover fixed utility costs from retail customers—are not discussed in this section. For more information on the merits of fixed charges for DG customers, see Linvill, Shenot, and Lazar (2013). For more information on minimum bills, which have grown in prominence to address utility revenue sufficiency issues caused by DPV in the United States, see Lazar (2014).

[26] Commercial and industrial customers may also have demand-based charges in their utility tariffs, which, in some locations, have been increasing to be equal to or more than the energy component. The details are very location-specific. See section 4.2.2 for more information on demand charges.

- Time-invariant energy rates (Section 4.2.1.1)
- Time-of-use energy rates (Section 4.2.1.2)
- Nonbypassable energy rates (Section 4.2.1.3)
- Inclining and declining block energy rates (Section 4.2.1.4)
- Critical peak pricing (Section 4.2.1.5)
- Real-time pricing (Section 4.2.1.6)

Importantly, these rate structures are by no means mutually exclusive, and it is possible to combine elements of these rate designs when developing retail tariff structures.

4.2.1.1 *Time-Invariant Energy Rates*

Many residential and commercial customers are on tariffs featuring a time-invariant (often referred to as "flat") volumetric energy rate; it is the most common configuration in the United States today. These rates are deemed time-invariant because they do not change based on the time that the customer consumes energy. Time-invariant volumetric energy rates are generally simple and easy to understand for consumers, easy to implement by utilities using simple electromechanical meters, and help to protect consumers from volatility in real-time electricity prices.

Placing a DPV-plus-storage customer on a time-invariant rate eliminates the possibility of arbitrage activities, as the customer only experiences a single price for energy throughout the day. For customers on time-invariant volumetric energy rates, however, there is no connection between their load consumption patterns, their DPV-plus-storage generation, and the actual system conditions at the time of consumption or generation. Absent a scenario where the utility is directly controlling the behind-the-meter system, there is no economic signal available to influence the behavior of customers to contribute to power system operations. From the utility and societal perspectives, this lack of an economic signal may constitute a foregone opportunity for the utility or utility's system to derive value from these resources.

4.2.1.2 *Time-of-Use Rates*

An increasing number of utilities are adopting TOU rates, driven by desires for more cost-reflective and system-friendly pricing, renewable energy grid integration challenges, and the growing ubiquity of advanced metering technologies enabling their implementation. Under TOU rates, a set of predetermined volumetric energy rates are applied to a customer's consumption, where the rates change based on the time of day, week, or year their energy is consumed (Lowder et al. 2017). TOU rates vary throughout a given time period in anticipation of expected system conditions and associated time-variant costs of power system operation. The time periods and rates are set well in advance of the time of consumption and are not adjusted to reflect actual conditions on the distribution system (Hogan 2014).[27] The implementation of TOU rates within billing cycles (as opposed to seasonal rates) requires metering solutions that can track energy consumption at the appropriate interval (e.g., hourly).

During periods of peak system-wide or localized demand, the utility's real-time cost of delivering electricity can increase drastically. With or without storage systems, if retail customers are even partially exposed to these price signals through a TOU rate, and if they have the ability to understand and respond to these price signals,[28] they may choose to reduce their consumption and thus contribute to easing system stress.[29] Importantly, TOU rates tend to economically incentivize DPV-plus-storage systems relative to time-invariant rates by offering customers

[27] This is distinct from critical peak pricing (CPP) tariffs under which customers pay significantly higher rates during a set number of periods when the grid is most constrained, in response to calls from utilities based on day- or week-ahead forecasted grid conditions (see Section 4.2.1.5).
[28] To respond to TOU rates, customers must either manually manage their electricity consumption and the operation of their storage-plus-DPV system or utilize smart infrastructure. A study on the effect of smart infrastructure in Baltimore showed that technology that alerted customers to prices and gave them the ability to reduce consumption during peak hours led to more significant peak consumption reductions than a TOU rate alone (Faruqui et al. 2012).
[29] TOU rates can be understood as a measured step in the direction of exposing retail customers to the real-time cost of electricity delivery, sending price signals to conserve energy during typical times of higher demand (or to use more energy during times of excess production), while still protecting customers from the full price volatility of real-time energy market conditions (Lowder et al. 2017).

the opportunity to derive value from temporal differences in the retail volumetric energy rate and/or sell rate for electricity—these energy arbitrage activities may or may not be desired by policymakers and regulators. In any case, TOU rates may be a useful tool for incentivizing DPV-plus-storage system deployment.

The details of how TOU rates are designed will influence the economic and technical impact that DPV-plus-storage systems will have on customers and the utility system. Relevant TOU rate design elements include, inter alia:

- **Pricing of TOU Periods**—the difference in the price of electricity between the various periods (e.g., between peak and off-peak energy rates) influences the potential for customer bill savings and the incentives for customers to shift consumption from the grid to lower-priced periods. The magnitude of customer responses to TOU rates is strongly related to the peak-to-off-peak price ratio: one study suggests that for every 10% increase in this price ratio, customers in TOU pilots in the United States reduced their on-peak demand by an average of 6.5% (Faruqui 2018).
- **Timing of TOU Periods**—setting peak periods outside the range of DPV production hours can influence the relative economics of a storage-plus DPV system, as customers with grid-tied DPV systems would otherwise be unable to take advantage of the difference between period prices (see the "Timing of TOU Periods" text box for more details).
- **Duration of TOU Periods**—creating longer duration peak period windows can be less effective in incentivizing customer behavior to match the system's needs. Longer duration peaks, around 5-8 hours, require more significant behavioral changes or longer-duration storage systems, which are typically more expensive, to reduce demand for the entirety of the peak period. Shorter duration peak periods, around 2-3 hours, will require less significant behavioral changes and less expensive, lower-duration storage systems to take advantage of the period pricing differences. As these periods are set well in advance, shorter peak periods are also less likely to coincide with actual individual system peak events, potentially eliminating the system benefit of modifying customer behavior. Importantly, customers who face TOU charges can still benefit from the addition of storage, even if storage system does not have enough duration to cover the entire peak period window, so long as the system can reduce the customer's total consumption during the peak period window.

Timing of TOU Periods

One key element of TOU rates that can influence the deployment of storage-plus-DPV systems is the timing of the peak period. If a DPV system's generation profile occurs primarily during off-peak price hours, the system owner may experience smaller reductions in their energy charges, particularly if they also cannot shift consumption to off-peak periods. They may also be incentivized to orient their panels in a particular direction to maximize production during peak periods (e.g., orienting panels to the west to maximize later-afternoon production). A storage-plus-DPV system, however, can help customers shift consumption to off-peak periods or shift exports to the grid during on-peak prices hours.

In this way, TOU rates can improve the economics of storage-plus-DPV systems relative to grid-tied DPV systems. McLaren et al (2019) demonstrates this effect in their modeling of storage-plus-DPV for commercial customers. They found that the presence of TOU elements in the retail rate increase the economic viability of storage-plus-DPV.

As PV penetration increases on power systems, previously on-peak hours may become periods of low demand and may eventually receive lower remuneration, further increasing the incentive for export-shifting capabilities. This has already happened in California, where all three of California's major investor-owned utilities have adjusted the peak period of their TOU rate to later in the evening to better align with the timing of their net load peak (Diau 2017).

Jurisdiction Examples

California—In California, all commercial, industrial, and agricultural customers are required to be on TOU rates. California utilities have also begun transitioning residential customers away from a flat rate toward a residential TOU rate. These residential TOU rates have already gone into effect for San Diego Gas & Electric and will go into effect in 2020 for Pacific Gas & Electric and Southern California Edison (SCE). Any customer who applies for California's Net Energy Metering 2.0 incentive scheme will be required to join a TOU rate. SCE offers a TOU rate (known as "TOU-D-PRIME") specific to households with electric vehicles, behind-the-meter storage, or heat pumps (SCE 2019). This rate has a seasonal and weekly aspect with different price periods depending on whether consumption occurs during the summer or winter, on weekends or weekdays. Regardless of season or day of week, the peak period occurs in a 5-hour window from 4 p.m.-9 p.m., well outside optimal solar generation hours, yet during SCE's anticipated system peaks.

4.2.1.3 *Nonbypassable Volumetric Charges*

A nonbypassable volumetric charge is a volumetric energy rate that a customer pays on every kilowatt-hour of electricity they consume from the grid (i.e., their grid consumption); however, unlike a traditional volumetric energy charge, the charge cannot be offset by receiving credits for DPV or DPV-plus-storage exports. In practice, this means that when the customer purchases electricity from the grid, they would be billed at the applicable volumetric energy rate and the nonbypassable charge rate. But when the customer exports DPV-plus-storage electricity, they are only compensated at the volumetric energy rate.[30,31] During the billing process, nonbypassable charges and volumetric energy rates would be tabulated separately. These charges reduce bill savings for DPV-plus-storage customers and are primarily implemented to promote utility fixed cost recovery, although they can support a wide range of functions, including energy efficiency or clean energy incentive programs.

Jurisdiction Examples

California—Customers under California's NEM 2.0 scheme are subject to a nonbypassable volumetric charge for purchasing grid electricity that cannot be offset. In California's NEM 1.0 scheme, customers paid a similar set of tariff riders on their net energy consumption; however, under the new scheme, a nonbypassable charge is applied to gross electricity consumption, and is tabulated separately than volumetric energy charges (CPUC 2016a). Using the definitions established in this report, the introduction of a volumetric nonbypassable charge to California's NEM program effectively makes it a net billing scheme.

Israel—Under Israel's NEM scheme, NEM customers are subject to a nonbypassable volumetric charge for both gross grid electricity consumption and DPV self-consumption. The charge was explicitly structured to recover utility costs from customers who depend on the bulk power system during periods of time without solar production. The Israeli NEM framework also features an additional nonbypassable volumetric charge for all DPV exports that is intended to remunerate the utility for the cost of integrating these variable renewable energy resources into the power system, following a calculation methodology established by the International Energy Agency (PUA 2014).

4.2.1.4 *Inclining and Declining Block Charges*

Under inclining block charges (IBCs) and declining block charges (DBCs), the volumetric rate for electricity increases or decreases, respectively, as cumulative electricity consumption within the billing cycle increases (see Figure 10).

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[30] Nonbypassable volumetric charges are a more useful construct for customers under NEM schemes, where kilowatt-hour credits are granted to offset energy charges, as opposed to net billing schemes which already feature energy charges that can be considered nonbypassable.

[31] The introduction of a nonbypassable volumetric charge into an NEM scheme would, based on the definitions established in this report, create a net billing scheme.

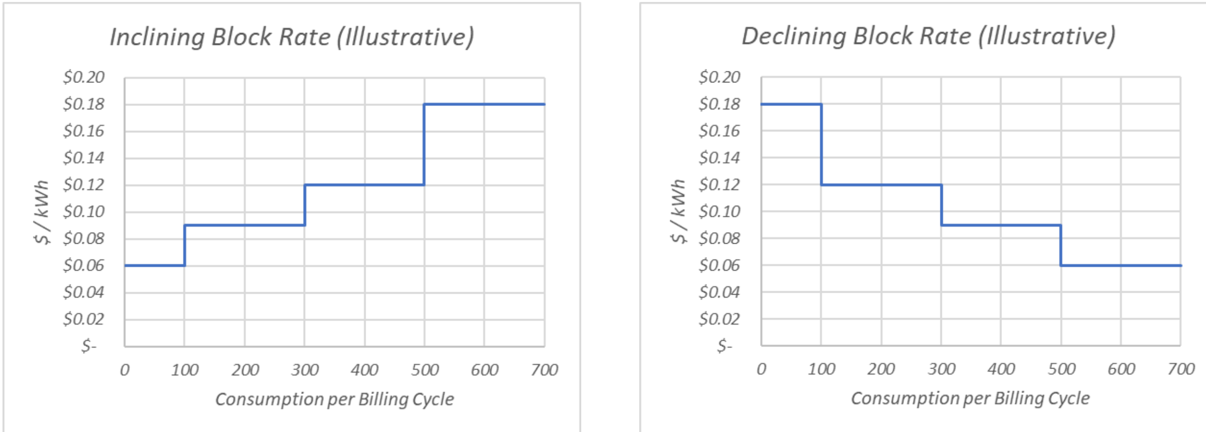

Figure 10. Illustrative diagram of inclining block rate (left) and declining block rate (right)

Source: Original

IBCs are common retail tariff components already present in tariff structures in many countries. They are not typically implemented specifically for DPV or DPV-plus-storage customers but can be considered as DPV or DPV-plus-storage programs are being designed. IBCs are typically implemented to promote energy conservation, as increasing energy consumption leads to higher retail prices, or as a matter of social policy, as policymakers may wish to subsidize low-usage (and often lower income) customers through tariff structures. For DPV customers, IBCs encourage DPV self-consumption, and could further incentivize the pairing of DPV and storage systems if consumption blocks grow sufficiently more expensive relative to the sell rate for exported DPV production.

DBCs, while relatively uncommon in the United States, can be considered as a tool to promote utility cost recovery from classes of customers which are increasingly supplying their own electricity through grid-tied DPV and DPV-plus-storage.

4.2.1.5 *Critical Peak Pricing*

An additional time-variant rate for regulators to consider is CPP. Under CPP schemes, prices are generally set to significantly higher levels during a set number of periods of system stress and will be lower outside of those periods. These higher peak prices are designed to better reflect the actual energy and capacity costs associated with providing electricity service during times of system stress.

Importantly, CPP schemes are activated in response to system needs by utilities. Utilities are required to notify customers at least one day in advance of an expected critical peak event, usually through phone calls or text messages. Regulators will typically limit the number of critical peak periods a utility can declare (e.g., 15 days per year during the season of system peak). Critical peak events can either be during the same set of hours for all events, similar to TOU on-peak rates that always occur during a predetermined set of hours, or can change from event to event as the system needs change. CPP schemes tend to provide a stronger price signal than more conventional TOU rates, while exposing customers to higher energy prices during relatively fewer number of hours per year. In some jurisdictions there has been resistance to implementing CPP because of the significantly higher prices during critical peak events. Customers may also consider CPP tariffs to be more intrusive as they must be regularly contacted by utilities in advance of the event (Faruqui et al. 2012).[32]

As with more conventional TOU rates, regulators must balance multiple objectives when determining the price differential between critical peak events and normal system operating periods. Larger differences between the two sets of periods tend to produce stronger demand reductions in customers and thus better align customer behavior with system needs. One variant of CPP is variable peak pricing, in which the price during critical peak events can

[32] Customer concerns surrounding privacy and intrusiveness under CPP tariffs can be partially alleviated by allowing the customer to designate which method of communication they would prefer (e.g., email, text, phone call). The use of enabling technologies, such as smart thermostats and water heaters, that respond automatically to utility price signals could also be used to minimize these concerns (Faruqui et al. 2012).

change from event to event to better reflect system conditions. In these cases, the new price is typically relayed to the customer when they are informed of the critical peak event. The ability of the customer to understand and respond to CPP notifications is key. The timing of the critical peak events also influences the economics of grid-tied DPV and DPV-plus-storage systems. As with TOU rates, critical peak events that fall outside of normal solar generation hours will create an incentive to pair grid-tied DPV systems with storage systems. Importantly, CPP can be combined with TOU rates, such that the utility is allowed to increase the normal on-peak pricing during critical peak events to further stimulate load reductions when the system is stressed.

Jurisdiction Examples

California—As a part of a pilot project, Sacramento Municipal Utility District (SMUD) outfitted 34 net-zero-energy smart homes with grid-interactive DPV-plus-storage systems to test their ability to provide a wide range of services such as regulation, spinning reserve, demand response, and peak load shifting (Jimenez 2014). In addition to the DPV-plus-storage, the houses were installed with smart thermostats to help enable customer responses to changes in electricity prices. Approximately half the customers were placed on a combined TOU-CPP rate to test the new rate's ability to induce load reductions. Customers on average reduced their demand by 1.35 kW during time-of-use peak periods and by 2.66 kW during critical peak events (Trabish 2015).

4.2.1.6 *Real-Time Pricing*

Real-time pricing, in which customers see and pay for the actual price of electricity at any time period of the day,[33] has only seen limited deployment for smaller commercial and residential classes, due to their historical inability to respond to such dynamic rates. For customers with sufficient infrastructure to see and react to real-time prices, these tariffs allow for the best alignment between customer consumption and utility electric system requirements (Hogan 2014). The increased price volatility associated with real time pricing may provide a strong incentive to store cheaper energy during off-peak periods for self-consumption during on-peak periods, which could increase the appeal of DPV-plus-storage; however, there is little experience and limited research to date on real-time pricing for residential and commercial customers and its effect on DPV-plus-storage economics and deployment.

Jurisdiction Examples

Texas—In Texas, which features a competitive retail energy market, some energy retailers offer "indexed" energy pricing schemes that shift a portion of wholesale energy market price risk to customers by tying changes in various market indices to retail energy prices (Texas Power Guide 2017).

Illinois—Ameren Illinois and ComEd offer real time pricing tariffs for residential customers. Under Ameren's Power Smart Pricing tariff, hourly prices for the next day are set the night before and communicated to customers so that they can adjust their consumption (Ameren Illinois 2019). Under ComEd's Residential Real Time Pricing tariff, prices are based on the actual hourly market price of electricity during the day, and customers on the tariff are alerted when these prices are high or are expected to be high so that they can adjust consumption (ComEd 2019). Both rates include an additional charge to cover the cost of ensuring adequate capacity, based on their contribution to system peak demand, similar to a demand charge. Again, the impact these tariffs have on customer adoption of DPV-plus-storage is unclear at this time.

4.2.2 Demand Charges

Demand charges are a per-kW fee applied to a customer's maximum consumption within a specified period. Demand charges are common for commercial and industrial customers, but less so for residential customers; however, utilities are increasingly exploring demand charges for smaller (i.e., residential and small commercial and industrial) customers and several U.S. jurisdictions have evaluated or implemented demand charges for customers with DG (Proudlove et al. 2018).

Many of the costs associated with delivering energy are closely related to the system's (and customer's) peak demand for electricity (kW), including costs of ensuring sufficient transmission, distribution, and generating capacity, rather than the total energy consumption within a given period (kWh). Although these costs could be,

[33] In jurisdictions with established wholesale electricity markets, customers are generally able to observe the wholesale price of electricity. In jurisdictions with vertically integrated utilities, customers' prices could be determined by the utility or regulator based on an ex-post evaluation of real-time system conditions.

and historically have been, recovered by the utility through volumetric energy rates, the use of demand charges can send an economic signal to customers to adjust their consumption during system peak hours to reduce system costs and improve reliability. Thus, demand charges may provide better incentives to customers to engage in load management through energy efficiency, storage, or DPV by providing an opportunity for bill reductions via reducing either their peak demand or demand during certain periods.

Key elements to consider when designing a demand charge include:

- **Coincident versus noncoincident charges**—A noncoincident demand charge is a per-kW fee that is applied to a customer's peak demand during a billing cycle. Noncoincident peak demand charges can be an effective tool for reducing individual customers' peak demand, and the generation and network costs associated with serving that peak demand. A coincident demand charge is a per-kW fee that is applied to a customer's highest demand during the *system's* peak demand period, the timing of which is typically specified in advance to the customer (Lazar and Gonzalez 2015). Coincident peak demand charges are an effective tool for aligning the customer's behavior with the needs of the power system by encouraging them to reduce consumption during periods of high demand (Passey et al. 2017). While both demand charge structures offer opportunities for bill reductions for DPV-plus-storage customers, coincident peak demand charges may offer a greater potential to alleviate system peak concerns relative to non-coincident charges (Darghouth et al. 2019). While non-coincident peak demand charges require continuous monitoring and control of the customer's grid usage throughout the day to be effectively minimized, coincident peak demand periods are typically only four hours in length, making effective demand management a more feasible task.
- **Peak demand period timing**—the timing of the demand period (if using coincident peak demand charges) will influence the economics of DPV-plus-storage systems relative to grid-tied DPV systems. If the peak demand window falls outside of the peak production period for a DPV system, this may serve as incentive to utilize DPV-plus-storage systems.
- **Peak demand period duration—**longer peak demand periods may reduce the customer's ability to reduce their maximum demand for the entire duration of the demand period. Shorter peak demand periods can better allow customers to shift their consumption outside the peak demand period and reduce both their strain on the power system and their bills, either through storage or behavioral changes. Put differently, demand charge reductions are typically greater from energy storage systems when peak demand periods correspond to the duration of energy storage capacity (Darghouth et al. 2019).
- **Averaging interval—**the peak customer demand applied to the per-kW demand charge fee is based on the average of their demand over a specific interval of time (e.g., every 15 minutes). Longer averaging intervals tend to create lower peak demand values used in the calculation of the demand charge, thereby reducing the overall opportunity for storage-plus- systems to lower demand charges (Darghouth et al. 2019). Shorter averaging intervals more accurately represent the customer's contribution to system peak demand and provide a greater opportunity to reduce demand charges.

Although DPV is also capable of reducing customer demand from the grid, its variable and uncertain nature and limited temporal range of generation (i.e., daytime) may interfere with its ability to reduce customer demand charges, such as if peak demand occurs after sunset or if cloud cover interrupts generation during a relevant demand measurement period (Darghouth et al. 2017). Unlike grid-tied DPV systems, DPV-plus-storage systems are—if managed properly—more dispatchable in nature. This allows these resources to more reliably reduce demand charges relative to grid-tied DPV systems, especially if combined with controls specifically designed to limit peak demand (Neubauer and Simpson 2015; Hledik and Greenstein 2016). Thus, as with TOU rates, the implementation of demand charges has the potential to increase the economic attractiveness of DPV-plus-storage systems. McLaren et al. (2019), for example, demonstrate that the presence of demand charges, particularly those greater than $10/kW, among commercial customers, contribute to larger bill savings for DPV-plus-storage systems relative to grid-tied DPV systems (McLaren et al. 2019).

Regardless of whether the customer has a grid-tied DPV or a DPV-plus-storage system, a key factor in the ability of these systems to reduce demand charges is the customer's underlying load pattern. Customers with "peakier" load patterns, assuming the peak of their load coincides with the demand peak period, are more likely to experience greater reductions in demand charges through the use of storage systems relative to customers with flatter demand patterns (Darghouth 2019).

Jurisdiction Examples

Massachusetts—One Massachusetts investor-owned utility, Eversource, gained approval from the public utility commission to institute a residential demand charge for customers who own rooftop-PV starting in 2019, based on noncoincident peak demand (Walton 2018). The rate structure will need to be revised, however, due to recent legislation requiring any residential demand charges to be based on coincident peak demand (Commonwealth of Massachusetts 2018). At the time of this writing, it is too early to tell whether this demand charge will incent DPV-plus-storage deployment in Eversource's service territory.

Arizona—In Arizona, utilities have begun offering rates that combine TOU rates with demand charges. Arizona Public Service (APS), for example, offers a Saver Choice Plus rate and a Saver Choice Max rate (APS 2018b; 2018a). In each of these rates, a customer's bill consists of three elements: (1) a basic service charge ($/month) that remains constant regardless of energy usage; (2) a peak hour usage (or demand) charge, which applies a flat charge ($/kW) to the highest demand of electricity during the system's peak demand hour for that billing cycle; and (3) an energy charge ($/kWh) that is applied to overall energy use, with a higher rate applied to energy used during predetermined on-peak periods and a lower rate applied to off-peak periods.

Despite their similar structure, Saver Choice Max has a significantly higher demand charge and lower energy charges than Saver Choice Plus. Customers able to shift more of their total energy consumption (kWh) during the predetermined peak hours to off-peak hours would benefit from the Saver Choice Plus plan, while those able to reduce their highest instantaneous demand consumption (kW) during the predetermined peak hours would benefit from the Saver Choice Max plan. Under either plan, DPV-plus-storage systems could allow customers to shift their consumption from periods of high prices to periods of low prices, as well as reduce the demand charge portion of their bill. Data on the impact of these tariffs on DPV-plus-storage economics and deployment are not available at this time.

4.3 Sell Rate Design

The sell rate, or the level at which DPV exports to the grid are credited, can be an important factor in the economics of both grid-tied DPV and DPV-plus-storage systems. Under NEM, the sell rate is the volumetric energy rate of the retail tariff.[34] In practice, under typical time-invariant volumetric rates, there is minimal economic benefit for pairing storage and DPV, as the grid is effectively being utilized as a free financial battery for DPV kilowatt-hour credits.

Under net billing, however, the sell rate is typically lower than the volumetric energy rate. Under these circumstances, there is an economic incentive to pair solar and storage together, since avoiding consumption from the grid through self-consumption is more valuable than exporting DPV generation. As with volumetric retail rates, the sell rate can be dynamic and time-variant in order to incentivize exporting of energy to the grid during certain peak periods or to discourage exports during periods of low demand.

With proper metering infrastructure in place, it may also be possible to implement distinct sell rates for DPV-originated energy versus grid-originated energy for DPV-plus-storage systems. While this possibility may not be immediately relevant for most programs, implementing distinct sell rates may help to encourage more fair and appropriate remuneration for customers and enable participation in aggregation schemes.

Jurisdiction Examples

Hawaii—Given Hawaii's extensive penetration of DPV resources, the region is coping with large injections of solar energy and distribution system limitations during the day and high ramping requirements for dispatchable generators in the transition from day to evening as solar resources taper off. Encouraging some customers to store this energy on-site and either consume this energy or send it back to the grid in the transition period or evening peak period not only helps reduce the surplus injections and address distribution limitations during the day, but also to mitigate the aforementioned higher ramp rate requirements. In this context, a series of tariffs was rolled out in 2015 to replace Hawaii's legacy NEM program. These tariffs were designed to limit the amount and time at which energy could be exported to the grid from customers. Under one of these, the 'Smart Export' tariff, customers with DPV-plus-storage installations are only compensated under a net billing scheme for energy exported to the grid between 4 p.m. and 9 a.m., while receiving no credits during the hours of prime DPV

[34] There may be a separate sell rate for expired kWh credits.

production capability (HECO 2019b). By creating a time-variant sell rate, participating customers are incentivized to store their excess DPV energy during the day and export it in the transition and evening periods.

In summary, the design of compensation mechanisms offers a number of opportunities to meet program goals. Metering and billing arrangements can emphasize different objectives and can be structured to support the highest regulatory priorities. Retail tariff design has a variety of volumetric energy rate options that can promote a variety of market outcomes, and demand charges are becoming an increasingly important component for reducing both customer bills and utility costs, particularly for DPV-plus-storage facilities. Finally, sell rate design can be an important component for decision makers to influence how customer's self-generation is utilized. In the future, separate compensation mechanisms for the provision of grid services may be an important economic factor for DPV-plus-storage customers.

5 Step III: Design Metering and Technical Configuration Requirements

The prioritized regulatory objectives identified, as well as the subsequent design of compensation mechanisms, tend to be a significant driver of technical configuration requirements and metering requirements for DPV-plus-storage systems.

Technical configuration requirements are the rules governing the allowed flows of energy between the customer's load panel,[35] the DPV system, the storage system, and the utility distribution system. Importantly, the responsibility for determining the exact technical details for how storage and DPV system are electrically coupled behind a customer's meter is typically left to the installer, as well as relevant codes and standards (in particular, the National Electrical Code [NEC] in the United States). Utilities, on the other hand, typically have comparatively little input into the configuration of these DERs behind the service meter. Regulators may be concerned with ensuring there is both clarity and certainty on the allowed technical configurations specified within relevant technical standards, codes and interconnection rules, and that no undue cost burdens are being placed on either participating or nonparticipating customers. Furthermore, regulators and utilities may be concerned with restricting particular power flows (e.g., battery exports to the grid) to accomplish certain objectives.

Metering requirements can be defined as rules governing which exact flows of energy must be measured using metering equipment, the specific technical requirements of metering infrastructure that must be installed, and where each meter must be placed within known technical configurations to ensure all desired energy flows are accurately measured. Compensation mechanisms designed to meet specific sets of prioritized objectives directly influence metering requirements. For instance, if DPV-plus-storage customers are placed on a TOU tariff, then the metering requirements must specify the ability of the meter to measure electricity consumption for prespecified time windows, which may necessitate the use of advanced metering infrastructure. Similarly, utility requirements may extend to metering infrastructure that is behind the service meter (which is the typical jurisdictional line of demarcation for utilities) to track certain power flows. Regulators must balance a desire to avoid excessive metering costs for customers and consumer privacy concerns with the need to encourage accurate measurements and billing practices through adequate metering infrastructure.

Both the technical configuration and the metering requirements imposed by regulators have important implications for the services battery systems can provide and the economics of these systems to customers, as well as the integrity of compensation mechanisms (see Section 5.3).

5.1 Technical Configuration Requirements

Energy storage systems can be connected (or coupled) to a DPV installation on either the AC or DC side of an inverter. The decision to couple DPV and storage systems in AC or DC configurations is made by either the customer or installer and depends on various factors, including the size of the systems, the desired use cases, and whether the system is new or retrofitted. Most new, smaller DPV-plus-storage installations are designed and built as DC-coupled systems, whereas retrofits with existing DPV systems or larger systems tend to be AC-coupled. For systems that primarily use DPV energy to charge the battery for use at a later time, AC-coupled systems have higher efficiency losses (due to multiple AC-DC conversions) than DC-coupled systems (Ardani et al. 2017). DC-coupled systems can be less expensive as they require only one battery-based inverter, whereas AC-coupled systems require a battery-based inverter and a grid-tied inverter for the PV array (Mullendore and Milford 2015).

Both AC- and DC-coupled configurations can be allowed by regulators and utilities as each system design suits different customer classes and use cases. Rather than exclude a particular coupling category, regulators may choose to allow a subset of the possible configurations for each coupling category to ensure that regardless of whether the system is AC- or DC-coupled, it engages only in desired operational behavior. In other words, it may be more pragmatic for regulators to be concerned with the allowed flows of energy between the customer's load panel, the DPV system, the storage system, and the utility network, rather than whether a particular system is AC-

[35] The load panel or service panel is the point of entry for power from the grid into the customer's premise. The service panel will be situated on the user side of the utility service meter and in nearly all circumstances belongs to and is the responsibility of the customer, not the utility.

or DC-coupled.[36] Unlike other forms of generation, storage has the capability to charge from either a paired DG resource or directly from the grid, and, absent specific discharge controls, it can export both grid-sourced and DG-sourced energy to the grid, as well. Figure 11 offers a conceptual diagram of the various origins, pathways and destinations of electricity for a DPV-plus-storage customer.

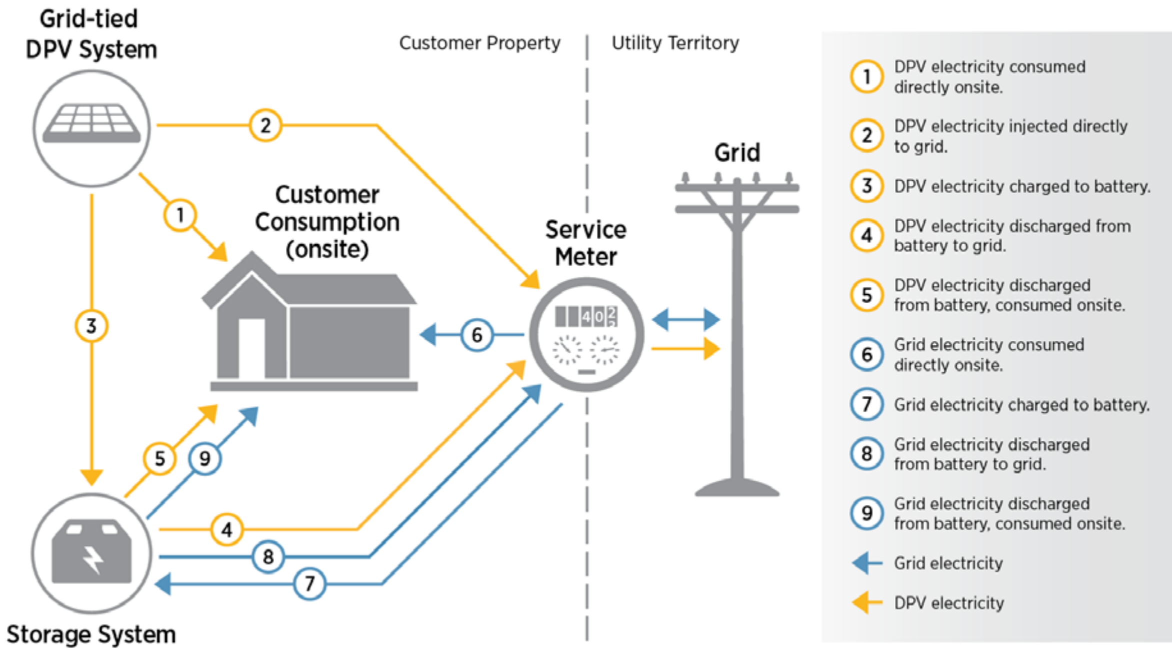

Figure 11. Energy origins, pathways, and destinations for behind-the-meter solar-plus-DPV customers

Source: Original [Illustration by Christopher Schwing, NREL]

Note: The "Service Meter" icon is intended to serve as a jurisdictional delineation between the customer and the utility. This illustrative diagram of potential energy flows does not depict other meters that may be necessary or appropriate for implementing a particular compensation mechanism.

Some regulators may wish to promulgate technical configuration requirements that constrain certain pathways of electricity flows (e.g., limiting the ability of the storage system to charge (⑦) from or discharge (④ or ⑧) to the electricity system for safety or other reasons). One common issue that regulators may be concerned with is mitigating inadvertent exports, in which non-exporting systems send energy back to the grid due to unanticipated mismatches between customer load and battery discharging, creating power quality disturbances or operational concerns for line workers during emergencies that cause local or larger area outages. Another concern may be cases in which both the DPV and battery system export their maximum capacity to the grid and potentially overload utility and/or customer equipment. Both issues can be mitigated through the implementation of battery control system requirements, which can be stipulated independently by or in collaboration among regulators, utilities, and other authority having jurisdictions (examples are included in Horowitz et al. 2019; Baldassari 2018). Battery control system requirements determine the allowable operations a battery system can engage in and can have important implications for the economics of the DPV-plus-storage system for customers, which may prompt regulators to take action to balance utility concerns with customer/installer interests. Related regulatory issues and approaches will be discussed in Section 5.3

5.2 Metering Requirements

Metering requirements will vary by the type of design configuration and whether a system is a retrofit or new installation. Requirements will also be strongly influenced by the compensation mechanism to which the DPV-plus-storage system is subject. At a high level, there are a variety of electricity flows that may be relevant for metering (see Figure 11), depending on the intended use case of the DPV-plus-storage system, such as total DPV exports (② + ④) to validate export credits, DPV production to validate renewable energy production (① + ②

[36] For more technical details on common technical configurations, see Appendix B.

+ ③), gross grid consumption (⑥ + ⑦) to accurately bill a nonbypassable volumetric charge, or total grid exports (② + ④ + ⑧) for use in a virtual power plant scheme, among other quantities.

According to McAllister et al. (2019) "directly metering behind-the-meter storage systems can give a utility additional insight into how storage systems are operating." Nevada's interconnection requirements, for example, require that storage systems be deployed with separate utility meters, the cost of which must be borne by customers and project developers. Separate metering provides data that can be used for distribution system planning, retail tariff design, and verification of compensation mechanism credits, according to NV Energy (McAllister et al. 2019; NV Energy 2018a). But requiring separate metering of storage systems increases costs for developers and customers, may require additional utility administrative efforts to process data, and may also raise customer privacy concerns.[37] Inverter software controls may be able to provide data that can assuage utility concerns about compensation mechanism credits and arbitrage activities, and serve as an alternative to separate metering (Noh et al. 2018); [38] however, there is still uncertainty as to whether inverter measurements are sufficient for tariff and policy compliance (from the utility perspective), have sufficient cybersecurity features, or cross traditional lines of demarcation between customers and utilities. Furthermore, inverter data may be output in a separate format than traditional metering data that utilities have experience processing, creating additional challenges for their use. In general, the presence of a DPV-plus-storage system may complicate efforts to accurately implement DG compensation mechanisms from the standpoint of metering and billing, relative to a grid-tied DPV system.

5.3 Preserving Compensation Mechanism Integrity

Metering and billing arrangements such as NEM or net billing are typically implemented to reward exported energy that is generated from an eligible distributed generation system (e.g., DPV). As DPV-plus-storage systems continue to permeate U.S. power markets, some decision makers have placed an increased emphasis during regulatory proceedings on ensuring that grid-supplied energy that is later exported by the storage system does not yield a financial reward using the DPV metering and billing arrangement. Addressing this issue can be broadly referred to as preserving the integrity of the DG compensation mechanism. A separate but sometimes related issue is monitoring and reducing energy arbitrage activities. Energy arbitrage is where DPV-plus-storage customers rely on time-variant price differences in the retail energy rate and profit by buying grid-supplied energy during less expensive periods and selling it back to the system during more expensive periods.[39]

Compensation mechanism integrity issues are typically addressed through technical configuration and metering requirements. In practice, decision makers have utilized several types of approaches, which are listed below from the simplest (and therefore least expensive for the user) to the more complex (with the highest relative costs). These include:

1. Estimating the customers' gross DPV production or DPV-originated energy exports using a simplified methodology
2. Mandating specific DPV-plus-storage technical configurations to prevent storage systems from charging from or exporting to the utility grid
3. Requiring adequate metering to track all quantities relevant to and from most or all devices for preserving compensation mechanism integrity.

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[37] Granular battery storage use information collected by a separate meter can potentially reveal the behavior and activities of a residence or business at a level of detail that customers may find intrusive.

[38] Utilizing inverter software as a utility-grade meter is an emerging opportunity being tested by some U.S. utilities. For instance, under Vermont's Green Mountain Power Resilient Home program, customers can either lease or use their own behind-the-meter storage system, receiving backup power services during outages and otherwise allowing Green Mountain Power to dispatch their system to reduce system-wide demand charges. The storage system is also utilized as a meter, effectively replacing an older single-purpose meter with a software-enabled smart meter that can measure and communicate real-time usage data to the utility. For more information, see: https://greenmountainpower.com/product/powerwall/.

[39] Energy arbitrage activities conducted by retail customers are not inherently negative for power systems. In some cases, they may be a cost-effective means to reduce and/or serve peak demand, or provide other valuable load shifting services. However, depending on how TOU rate are designed, retail arbitrage activities have the potential to exacerbate existing cost-shifting issues associated with DPV deployment. A discussion of the costs and benefits of retail arbitrage activities is outside the scope of this report.

Importantly, these approaches are not mutually exclusive. For instance, system size limits can be used to apply distinct approaches to DPV-plus-storage systems of different sizes within the same jurisdiction (see California example in Section 5.3.1). This is applied to ensure that the administrative and infrastructure-related costs associated with preserving compensation mechanism integrity are commensurate with the potential impact of the corresponding systems. Offering alternative options that are equally satisfactory approaches for regulators and utilities to ensure compensation mechanism integrity can help system owners choose the most appropriate method for their specific set of circumstances and intended uses.

While each of the three methods discussed in subsequent sections has associated drawbacks, these drawbacks may be applicable to or precluded by specific regulatory objectives. Tracking clean energy production for regulatory compliance for larger-scale behind-the-meter systems might fit best with a highly accurate method, such as requiring additional metering infrastructure. Preventing the inaccurate crediting of energy from ineligible sources, meanwhile, could be managed through limiting technical configurations, which are financially and administratively less burdensome than additional metering. Conversely, maximizing the value of the battery to the grid could be achieved through estimation or metering methodologies which do not limit the operational capabilities of the DPV-plus-storage system. The relative priority of each goal tends to dictate the method chosen. In general, the more granular control and observability one wants over the DPV-plus-storage system, the more expensive or administratively cumbersome the appropriate method may be to implement.

5.3.1 Using Estimation Methods for DPV-Plus-Storage Export Crediting

One method to ensure DPV-plus-storage system owners are fairly compensated without the need for additional metering is to set a cap on export credits available to these systems based on an estimation of expected DPV generation. At the end of each billing cycle, the customer's metered exports are compared against an estimation of generation conducted by the utility using a prespecified methodology, and the customer receives the lower of the quantities as a bill credit. In practice, these approaches can be used when the cost of additional metering represents a large proportion of overall project costs (i.e., for smaller systems) or when the risk/scale of compensation mechanism integrity violations (i.e., gaming and arbitrage activities) is low.

Although not as accurate as direct metering, this simplified method gives an approximate value for generation from the eligible DPV system without the need for customers to install additional metering equipment beyond what is required for a grid-tied DPV system. Given an adequately granular estimation of the solar resource available in a specific time period and the size of the generating system in question, utilities can use techno-economic performance analysis tools (e.g., NREL's System Advisor Model) to estimate the output of a qualifying generating system. Utilities can also use more simplified approaches, such as determining a rough kWh per kW factor for energy production for systems within a given region. The values estimated from these methods can then be used to grant the customer credit for their generation based on the size of their DPV system, regardless of the charging or discharging of their paired storage system. While estimation approaches are the least expensive approach to preserving compensation mechanism integrity, they are also likely the most inaccurate and may entail an administrative burden for utilities who must develop estimation methodologies and integrate them into bill processes.

Jurisdiction Examples

California—in California, an NEM scheme remains the primary mechanism for compensating DERs like DPV. For DPV-plus-storage systems where the battery power output is under 10 kW, the California Public Utilities Commission (CPUC) implemented a generation credit estimation methodology in lieu of requiring more metering equipment or limiting the capability of the battery to charge/discharge from the grid. Under this scheme, California utilities are required to calculate the projected DPV generation for each DPV-plus-storage customer in a particular month in a particular region using a calculation methodology approved by CPUC (CPUC 2016b). Customers are then assigned the lesser of the actual exports to the grid or the estimated DPV generation. While this methodology tended to overestimate DPV production (unless a customer has no on-site consumption for an entire month), the ability of smaller customers to game the NEM compensation mechanism was assumed to be negligible. While the initial scheme was implemented in 2016, the methodology was updated by the regulator in 2018, following complaints from utilities that the analysis process was too administratively burdensome; currently, a simpler kWh-per-kW profile for each climate zone in the region is now used (CPUC 2018b). This profile is used along with the DPV system size to determine the likely amount of renewable energy exported to the grid, and customers are credited for exports to the grid up to this estimation. Additionally, provided the storage system is under 10 kW, there are no limitations on the maximum output power of the battery system relative to the maximum output capacity of the paired, NEM-eligible generator. This is partly due to the limited battery sizes below 10 kW available to customers, and partly due to the limited ability of smaller battery systems to meaningfully violate NEM integrity principles at-scale (CPUC 2014; 2016b).[40]

5.3.2 Ensuring Accurate Metering Through Design Configuration Limitations

An alternative method to ensure more accurate measuring and appropriate crediting for energy exports is to limit the types of DPV-plus-storage design configurations eligible for interconnection. These approaches typically involve limiting the ability of the storage system to import from or export to the grid using system controls. Common design configuration limitations include:

1. **Storage can only charge from DPV, no storage exports allowed**—a limited configuration that constrains the use of stored DPV energy for self-consumption only, and does not allow grid charging of the battery; the only energy eligible for credit under the DPV compensation mechanism is DPV energy that is produced and immediately exported to the grid.
2. **Storage can charge from DPV and grid, no storage exports allowed**—this configuration allows the customer to charge from both the DPV system and the grid, but the storage system is not able to export to the grid. Only DPV energy that is not immediately used or stored is exported to the grid and credited.
3. **Storage can only charge from DPV, storage exports allowed**—a less limited configuration where the storage device is allowed to export stored DPV-originated energy to the grid and receive credit under the DG compensation mechanism.
4. **Storage can only charge from the grid, storage exports allowed**—a limited configuration where the storage device is allowed to charge from and export to the grid, but is not allowed to interact with the DPV system.

In general, design configuration limitations ensure that any customer exports to the grid come exclusively from on-site generation, eliminating concerns of compensation mechanism integrity and energy arbitrage using grid-supplied energy. But only allowing the storage system to charge from the paired DPV system limits the ability of the energy storage system to become grid-interactive and provide valuable system services to the utility distribution system (e.g., congestion management) or the transmission network (e.g., frequency regulation). As opportunities expand for DPV-plus-storage systems to derive value from providing the broader power system with energy services (see Section 8.6), these limited design configurations may result in a lost opportunity in the future for both system owners and utilities—thus, limited design configurations should be considered through both a short-term and long-term lens.

Jurisdiction Examples

Hawaii—In Hawaii, NEM was closed to new participants in October 2015 and replaced with a transitional market structure featuring two interim systems and associated tariffs, which limited the amount and time at which energy could be exported to the grid from customers. Under the Customer Self-Supply option, customers who install DPV or DPV-plus-storage systems in configurations, which preclude exports to the grid, require interconnection review prior to installation, but are eligible for expedited review processes, including in areas that have already exceeded voltage limitations due to higher solar photovoltaic penetrations (HECO 2019a). This tariff incentivizes customers to install storage to maximize the consumption of their on-site DPV resource—the output of which may or may not naturally coincide with customer demand—and reduce their own consumption from the grid.

California—For DPV-plus-storage systems with batteries larger than 10 kW in California, regulators determined the estimation methodology used for smaller systems would not be sufficient to ensure NEM integrity and discourage arbitrage activities. These systems were instead required to use either a limited design configuration or additional metering (CPUC 2014). For the limited design configuration option, systems must install a nonexport

[40] Violating NEM integrity principles here refers both to the misallocation of NEM credits to non-NEM-eligible generation and to the potential for arbitrage or relying on price differences in the retail rate of electricity to profit by buying energy during less expensive periods and selling it back to the system during more expensive periods. CPUC found that "[w]hile arbitrage is a theoretical concern under both methods … [it] would be uneconomical based on current battery costs, current differentials in TOU period pricing, and round trip efficiency losses of 10-20%" (CPUC 2016b, 20).

relay on the storage device, which excludes the exporting (and thus, crediting) of grid-charged energy back to the grid, ensuring the actual amount of NEM-eligible generation can be accurately calculated (CPUC 2014). Regulators also instituted a battery sizing requirement for all batteries larger than 10 kW to ensure its primary functions are to augment the value of the paired NEM-generator and satisfy on-site demand, instead of performing arbitrage activities using TOU rates. The maximum output power of these paired storage systems may not exceed 150% of the paired NEM-generator's maximum output capacity, and the storage system's energy capacity is limited to a maximum of the energy equivalent of 12.5 hours of discharge at the maximum power capacity.[41] The NEM-generator, in turn, was originally limited to 1 MW in capacity under the original NEM tariff, but under California's new net metering scheme (NEM 2.0) there is no maximum size limit, although all systems over 1 MW are required to pay associated interconnection fees (CPUC 2016a).

Colorado—As with larger systems in California, Xcel Energy in Colorado only grants Renewable Energy Credits (described further in Section 8.3) to NEM-eligible renewable generation systems that are either configured so as to prevent the export from the battery to the grid, or that have adequate metering in place to appropriately assign Renewable Energy Credits (Xcel Energy 2018, 191–92).

Nevada—In 2018, the Nevada Public Utility Commission passed an interconnection rule that restricted energy storage devices paired with NEM-eligible DG systems such that they are either: (1) technically restricted from exporting energy to the distribution system altogether; or (2) technically restricted to being charged only from the customer's NEM-eligible DG system (NV Energy 2018a, 18).

New York—Although New York is transitioning toward its Value of Distributed Energy Resources tariff structure, at the time of this writing it still relies on a NEM framework, and concerns have been raised over distributed storage's potential to game NEM crediting schemes. To address these concerns, the New York State Department of Public Service approved a Hybrid Energy Storage System Tariff for DPV-plus-storage systems which would qualify for NEM credits (NYPSC 2018b). The tariff allows four different qualifying configurations, two of which involve limited configurations which demonstrate systems exclusively charge from eligible DERs and limit exports of grid-supplied power.

5.3.3 Require Adequate Metering to Track All Quantities Relevant for Preserving Compensation Mechanism Integrity

A final method for ensuring compensation mechanism integrity is requiring additional metering equipment. Installing additional metering to track the flow of energy within DPV-plus-storage systems is undoubtedly a robust method for preserving compensation mechanism integrity. It may also enable grid interactivity and participation in (likely not-yet-developed) grid services schemes (e.g., a virtual power plant scheme); however, a requirement for additional metering beyond what is needed for grid-tied DPV systems may incur significant costs, depending on the customer, particularly in the case of retrofitting existing systems with new meters. These costs may outweigh the benefits associated with more accurate measurements, particularly for smaller residential systems, which have a limited capacity to engage in energy arbitrage activities or to profit from selling grid-supplied energy back to the grid using DG compensation mechanisms.

Jurisdiction Examples

California—As an additional option for >10 kW storage systems beyond design configuration limitations, regulators offered additional metering as an alternative means of ensuring NEM integrity. For DPV-plus-storage systems with batteries larger than 10 kW, system owners had the choice to "[1)] install an interval meter for the NEM-eligible generation, meter the load and meter total energy flows at the point of common coupling; or [2)] install interval meter *(sic)* directly to the NEM-eligible generator(s)" (CPUC, 2014). Both of these methods ensure the actual amount of NEM-eligible production and exports can thus be accurately calculated for billing and goal-tracking purposes.

New York—In addition to the limited design configurations listed above, New York's Hybrid Energy Storage System Tariff also allows for systems with sufficient metering equipment to qualify for NEM credits. For paired systems with appropriate telemetry and metering infrastructure on the storage system, credits are calculated by

[41] For example, if a storage system had a power rating of 4 kW, then its energy capacity rating could not exceed 50 kWh.

taking the difference of the net hourly injections measured at the customer meter and any discharges recorded on the storage system meter (NYPSC 2018b).

Massachusetts—In 2017, the Massachusetts Department of Energy Resources established the Solar Massachusetts Renewable Target (SMART) Program to incentivize solar statewide. Eligible storage systems co-located with solar can receive an incentive adder (Department of Energy Resources 2017). To qualify for the program, solar-plus-storage customers are required to purchase a utility meter that measures their solar production. This requirement has prompted formalized concerns from installers that: (1) the cost of additional metering eats into incentive savings, reducing potential deployment; and (2) additional metering is unnecessary, because certain advanced inverters are capable of accurately tracking solar generation for SMART program compliance. Utilities contest the magnitude of additional metering costs and prefer revenue-grade metering technology. The Massachusetts Department of Energy Resources has yet to determine if advanced inverters are an acceptable alternative to additional metering for the SMART program (Spector 2019).

Behind-the-meter energy storage systems are dynamic and flexible energy resources, able to act as both a source of power and energy during some time periods while being a load with demand and energy needs at other time periods (or may be neither source nor load at other times). The technical design and configuration of such systems affect their ability to interact with the grid. Taking a purely technical perspective, storage systems can be designed to charge from the grid and/or an on-site distributed energy resource (e.g., DPV), and the charging source and/or duration may be limited by the distribution system operator. Similarly, they can also be designed to discharge to the grid, serve on-site customer electricity demand, or both through value stacking.

In reality, however, behind-the-meter energy storage system design configurations are often (though not exclusively)[42] influenced by a desire to reduce the hosting customer's electricity bill or provide reliability services during outages, which is influenced by how retail tariff structures and distributed energy resource compensation mechanisms are designed. When serving on-site power and energy needs, these systems might be technically optimized to reduce monthly power demand charges, take advantage of TOU tariffs, maximize DPV self-consumption (when paired with a storage system) and avoid power and energy exports, and/or provide backup during outages or periods of grid instability. In any case, this technical design flexibility brings both challenges and opportunities for system owners, utilities, and the power system at large that utility regulators can understand to fairly and effectively regulate this technology.

[42] In some cases, the design and operation of third-party owned BESS may be optimized by developers to provide a specific type of bankable grid service (e.g., demand response in a power market).

6 Step IV: Design Interconnection Rules

Interconnection rules govern both the procedural elements and technical requirements associated with connecting a DPV-plus-storage system to the power system. They also communicate a variety of expectations to utilities, developers, and installing customers. Regulators can play an important role in guiding the overall development of DPV-plus-storage interconnection rules, which can be understood through the following categories:

- Rules governing interconnection application procedures and management offer guidance on the process for how developers and utilities must interact. These rules specify the various steps that each stakeholder must take in the overarching process of formulating, evaluating, and ultimately approving or rejecting applications to interconnect to the power system. Specific rules about the interconnection process may include aspects such as mandated time frames for utilities or developers to take various steps (e.g., screen an application, respond to an inquiry), standardized data requirements that developers must provide to utilities in an application, requirements of how much information utilities must provide developers about the process, standardized terms of interconnection agreements that are ultimately executed between the customer and utility, schedules of interconnection fees, and dispute resolution processes, among others.
- Rules governing grid requirements offer guidance on which electrical equipment standards that system components must comply with, the technical configuration, metering, monitoring and control requirements, and the various technical requirements for how the system should be interacting with the power system during normal and abnormal operating conditions. Many model equipment standards (e.g., UL 1741) and interconnection standards (e.g., IEEE 1547) already exist in the United States for DERs, and regulators are often tasked with directing utilities to draw from these existing resources and/or engaging with the utilities and the public to adapt these resources to local conditions. When considering grid requirements, regulators typically attempt to balance a desire for: (1) the safety of utility workers and the general public; (2) the reliability and service quality of the distribution system; and (3) the affordability of equipment (and associated installation labor) needed to comply with requirements.
- Rules governing interconnection application technical review practices offer guidance on the technical criteria and associated procedures that utilities must utilize when evaluating an interconnection application, with a specific focus on how the proposed DPV-plus-storage system will impact operations on the distribution circuit where it will be constructed. This includes various screening criteria for when a particular application can be fast tracked for approval or may be flagged for supplemental or formal engineering review. In this realm, regulators are typically balancing a desire to avoid adverse distribution system impacts with a desire to ensure evaluation processes and criteria are not unnecessarily burdensome for consumers. Regulators may also provide guidance on cost allocation in the event that more expensive engineering studies or network upgrades are required to permit interconnection.

The design of interconnection rules involves the codification of regulatory decisions surrounding compensation mechanism design and metering and technical configuration requirements discussed in previous sections. While their exact role can vary greatly from region to region, regulators are increasingly playing a leading role in the adaptation, adoption, and public dissemination of existing interconnection standards and codes. Figure 12 illustrates the typical high-level process of navigating DER interconnection and permitting, beginning with application submission and ending with the utility granting the system permission to operate. The figure also highlights which authority or actor typically oversees each step of the process, as well as examples of which rules, requirements, standards, and codes the storage or DPV-plus-storage system may be subject to at that particular step. It is important to note that the requirements included in the figure are intended as examples, and systems may be subject to different and/or additional rules depending on the jurisdiction. As well, the term authority having jurisdiction (AHJ) is used to describe any local authority that has oversight or control over a relevant permitting process—issues related to permitting and AHJs are discussed in Section 7.

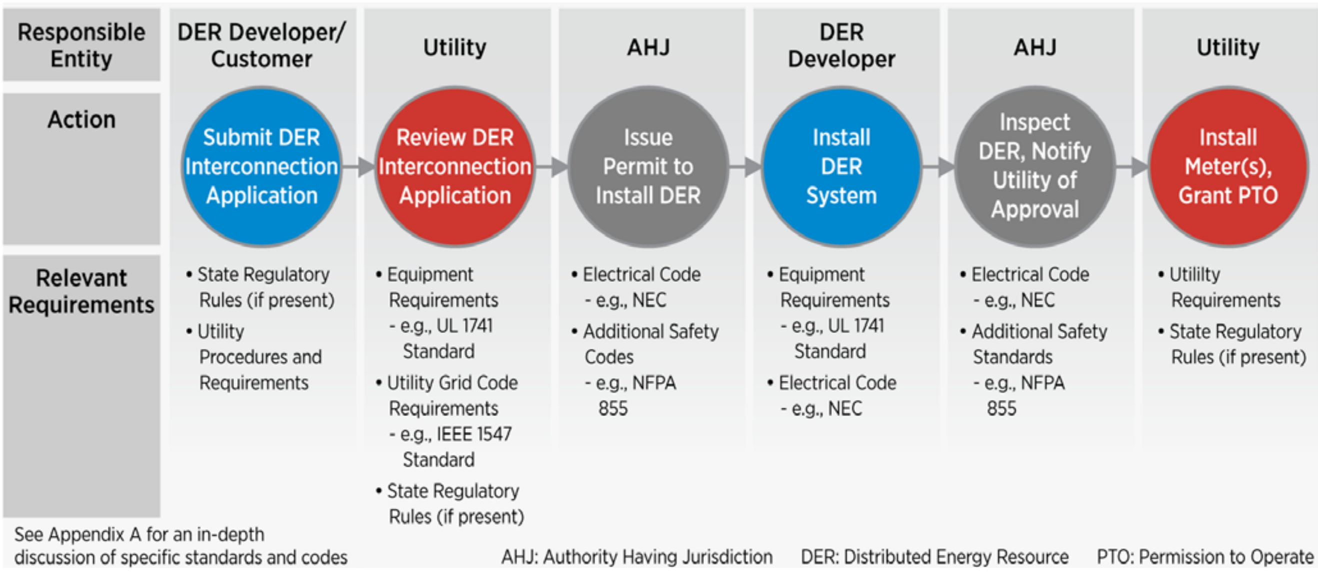

Figure 12. Typical DER interconnection and permitting process

Source: Original [*Illustration by Alfred Hicks, NREL]*

Importantly, many regulators attempt to create standardized processes, applications, and technical requirements across their jurisdiction; doing so may help to ensure all applications are reviewed on a nondiscriminatory basis, and also reduces the need for developers to learn an entirely new set of interconnection procedures and requirements for each utility service territory.[43] A key trend in creating such standardized processes is to customize interconnection rules based on system capacity (see Section 2.2), with smaller systems being subject to less rigorous interconnection requirements.

In the United States, regulators have pursued several distinct approaches to address interconnection processes in response to increasing DPV-plus-storage deployment. These include:

- Actions which clarify that existing interconnection rules for small-scale distributed energy resources apply to storage (e.g., California, Colorado, Iowa, North Carolina, and New Mexico);
- Actions which develop separate interconnection rules for DPV-plus-storage systems to address some of the unique operational features of storage (e.g., California and Nevada), including:
    - Actions which distinguish between non-exporting and exporting DER systems and apply exceptions or modifications (e.g., expedited review, limited review, or no review) for non-exporting systems that interact less with the grid (e.g., California, Colorado, New York, Hawaii, Arizona [proposed]); and
    - Actions which customize the rigorousness of interconnection rules, with specific technical requirements, including applicable standards and codes, based on the size of the applying system (e.g., New York, California).

6.1 Rules Governing the Interconnection Application Procedures and Management

Interconnection processes for DERs have been discussed at length in the literature (see Horowitz et al. (2019)), and have also been promulgated by utilities and regulators (see NYPSC (2017)). In practice, DPV-plus-storage interconnection processes may be quite similar to (or even the exact same as) processes for grid-tied DPV systems. While their exact role can vary greatly from region to region, regulators may be interested in addressing some or all of the following set of issues related to interconnection application procedures and management (this section draws heavily on Horowitz et al. (2019)):

[43] In some cases, utilities can have additional utility-specific requirements not specified (but authorized) by the regulator.

Interconnection Pre-Application Rules

- **Public Communication of Interconnection Process:** Regulators may wish to ensure that information about DER interconnection processes are broadly available to the public. This may involve requiring utilities to: (a) post relevant information on their website, such as frequently-asked-question pages or other customer-facing documentation that describe the various steps in the application process, data requirements, timelines, and fees; (b) provide reference materials such as example application documents, sample line diagrams, technical requirement documentation, or instructional videos; and (c) host trainings or webinars for developers and customers. In many cases, utilities may take these (or similar) steps without regulatory intervention, but regulators may nevertheless wish to set a minimum standard for public outreach and communication.
- **Availability of Data on Interconnection Feasibility:**[44] Regulators may wish to expand the availability of information on the technical feasibility of interconnection at various points on the utility distribution system. This can occur through the issuance of pre-application reports, where developers request the utility to provide readily available information on the potential limitations of a specific distribution circuit where they are considering developing a project. In this case, regulators may need to help determine a reasonable cost that utilities can charge developers for this service, as well as mandate a time frame for providing the report. Regulators may also wish to ensure utilities publish and periodically update DER hosting capacity maps, which visually communicate technical information on the feasibility of DER interconnection to the public, such as is currently available from California investor-owned utilities.[45] Hosting capacity maps can help grid-tied DPV and DPV-plus-storage developers understand the maximum capacity of DER systems that can be installed in a specific location, saving developers time and energy by avoiding areas with lower probabilities of successful interconnection. For more information on hosting capacity maps and analysis, see the text box in Section 6.3.2.

Interconnection Application Rules

- **Utility-Developer Communication**: Utilities and developers/customers may need to interact throughout the interconnection process to address various requests and questions. Regulators may wish to ask utilities to provide a single point of contact for each applicant to answer interconnection-related questions or guarantee the right of applicants to request scoping meetings with utilities to discuss interconnection requests and review applications. Such requirements can help to reduce developer uncertainty, streamline communication, and limit confusion on application statuses and next steps.
- **Interconnection Application Form Design**: Regulators may wish to directly design, provide input to, and/or formally review and approve interconnection application forms, which provides a variety of relevant data to utilities about prospective projects. Typically, regulators aim to ensure that applications are sufficiently clear and understandable for customers and provide a reasonable amount of information to utilities to evaluate requests. In some cases, larger systems may merit separate application forms with additional information requirements.
- **Application Submission Procedures**: Regulators are often concerned with ensuring a fair and transparent process for submitting and evaluating applications. In the realm of fairness, utilities may be required by regulators to process applications on a first come, first served basis in the event that multiple applications are submitted for projects on the same feeder. Regulators may also require utilities to offer an online application submission process and/or an online application status tracking tool. They may also wish to specify utility protocols in the event of an incomplete application submission by a developer.
- **Application and Study Fees**: Regulators typically specify or review utility proposals for customer fees that may be charged when interconnection applications are submitted and/or additional engineering studies by the utility are required.

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[44] It is important to note here that feasibility refers broadly to the ability of a prospective grid-tied DPV or storage-plus-DPV system to be interconnected to the power system without compromising reliability or resilience. This is independent of the more industry-specific definition of a feasibility study, which larger utilities may require for larger, front-of-the-meter installations.

[45] For two examples of these maps, register here for PG&E: https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page, or here for SDG&E: https://www.sdge.com/more-information/customer-generation/enhanced-integration-capacity-analysis-ica.

Interconnection Process Rules

- **Overarching Structure of Interconnection Process**: Regulators are typically involved in developing the overall progression of steps in the interconnection process, including aspects such as (but not limited to) initial application submission, preliminary application reviews, utility technical screening, supplemental engineering studies (if merited), distribution system mitigation upgrades (if merited), project construction, system testing and certification, and final system verification. In practice, a given interconnection process can go in a number of different directions, depending on how an application progresses through the various steps, and what types of additional utility-developer interactions and/or additional engineering studies are required. Regulators may wish to play a role in developing a standardized utility process that helps streamline the overall process and reduce developer uncertainty.
- **Mandated Time Frames for Interconnection Process:** Regulators are often focused on mandating the maximum allowable time frame for utilities and developers to take various steps in the interconnection process, such as a maximum response time for a utility to evaluate an application or conduct an engineering study, or for a developer to respond to a request for more information from the utility. Creating guidelines for response times from utilities and DER developers helps to reduce uncertainty for all parties, ensuring that applications waiting in a queue for a particular distribution circuit are not unnecessarily delayed.
- **Dispute Resolution Processes**: Regulators may wish to specify a predetermined procedure, which is followed in the event that a dispute occurs between the utility and developer related to the implementation of the interconnection process. This process is typically specified within an interconnection agreement. Regulators may provide general guidance on the location, time frame and method for dispute resolution (e.g., enrollment of a mutually acceptable mediator in a mutually convenient location within 30 days), and/or may interject as the mediating authority themselves if a resolution cannot be met through the initial process.

Screening Rules

- **Technical Screening Procedures**: This issue will be discussed in additional detail in the Section 6.3.

Final Interconnection Rules

- **Terms of Interconnection Contract**: Regulators may directly design, provide input to, and/or formally review and approve utility- or jurisdiction-specific interconnection contracts. These contracts outline the terms of the legal agreement between the utility and the customer, allowing the customer to sell electricity back to the utility and detailing a variety of rights and restrictions to which utility and customer are subject. In some jurisdictions, regulators directly promulgate standardized interconnection contracts that balance utility and customer interests.
- **Cost Allocation for Grid Upgrades:** In the event that a distribution system upgrade is required to accommodate a prospective DER, regulators must specify who is responsible to pay for the cost of the upgrade. Deciding how upgrade costs can be allocated equitably can be a challenging task.[46] This is typically addressed through the promulgation of a broadly applicable set of regulatory rules.

[46] See Section 6 of Horowitz et al. 2019 for more information on this topic.

The relative role of regulator versus utilities in creating these rules is summarized in Table 3.

Table 3. Roles and Responsibilities for Interconnection Application Procedures and Management Rules

	Rule Category	Typical Roles and Responsibilities
Pre-Application	Public Communication of Interconnection Process	Utilities are typically responsible for communicating with their customer base about the interconnection process; under some circumstances, regulators may motivate utilities to do so through rules or requirements on public communication of the interconnection process.
	Availability of Data on Interconnection Feasibility	Under most circumstances, regulators have intervened to motivate utilities to provide pre-feasibility assessments for interconnection. Some utilities have also provided this data voluntarily or choose not to provide it at all.
Application	Utility-Developer Communication	In some cases, regulators may intervene to specify the procedures for utility-developer communications. In other cases, this is handled solely by the utility.
	Interconnection Application Form Design	In cases where regulators are creating standardized state-wide interconnection processes, they will typically lead the development of interconnection application form design, with input from utilities. In other circumstances, utilities will create interconnection applications independently with varying levels of regulatory oversight.
	Application Submission Procedures	In some cases, regulators intervene to provide either high-level or detailed guidance on various aspects of the application submission procedure. In other cases, utilities may lead the creation of these procedures with limited to no regulatory oversight.
	Application and Study Fees	Regulators frequently specify the maximum interconnection application fee and detailed impact study fee that utilities may charge various types of retail customers.
Interconnection Process	Overarching Structure of Interconnection Process	There are a wide range of possibilities regarding the design and promulgation of interconnection processes. On one end of the spectrum, regulators have led the development of standardized interconnection processes for states. On the other end of the spectrum, regulators have left the design process fully to utilities. In the middle, regulators may pick specific areas where they wish to intervene or oversee utility activities.
	Mandated Time Frames for Interconnection Process	Regulators often, but not always, specify maximum time limits for various steps in the interconnection process.
	Dispute Resolution Processes	Regulators oftentimes, but not always, specify the rules and procedures surrounding dispute resolution processes between utilities and developers. They very frequently serve as the "backstop" dispute resolution body between developers and utilities, should other means not lead to resolution.
Screening	Technical Screening Procedures	In cases where regulators are creating standardized state-wide interconnection processes, they will typically take a leading role in developing technical screening procedures, in close collaboration with utilities. In most other cases, utilities play a leading role in developing technical screening procedures, with varying levels of regulatory oversight. In some cases, these screens may be based on screening procedures that are promulgated by a federal government entity, such as the Federal Energy Regulatory Commission Small Generator Interconnection Procedures technical screens in the United States.
Final Interconnection	Terms of Interconnection Contract	In some jurisdictions, regulators directly promulgate standardized interconnection contracts that balance utility and customer interests. In other cases, utilities play a leading role in developing the terms of the interconnection contract under regulatory oversight.
	Cost Allocation for Grid Upgrades	Regulators are tasked with developing the set of rules governing how costs are allocated among utilities/ratepayers and interconnecting customers, should a grid upgrade be required to accommodate an interconnection request.

6.2 Rules Governing Grid Requirements

In addition to rules governing interconnection application procedures and application evaluation protocols, the promulgation of grid requirements is an important element of regulating interconnection processes. Grid requirements typically comprise equipment requirements, which govern technical capabilities and quality of DER equipment, and interconnection requirements, which govern the interactions and interoperability of equipment with the broader power system.

The establishment of grid requirements within a given regulatory jurisdiction helps to establish the minimum technical parameters that DPV-plus-storage systems must exhibit to safely interconnect to an electrical power system. Their implementation helps to ensure standardized, predictable behavior from all interconnected distributed assets, which safeguards against DER interfering with the safe operation of the power system, enables DER to help restore the power system to normal operating conditions during frequency and voltage excursions, ensures the safety of utility line workers, and allows DER to contribute to the broader reliability of the power system given adequate facilitating infrastructure (see Sections 8.5 and 8.6 for examples of DER providing system energy and ancillary services). Regulators have an important role in the development and adoption of grid requirements, including the adaptation of established international equipment and interconnection standards to local power system conditions, and the regular update of interconnection requirements to keep pace with changing system conditions.

In general, equipment requirements and interconnection requirements rely on established standards developed by national and international standard-setting organizations (e.g., Institute of Electrical and Electronics Engineers [IEEE]) and safety certification bodies (e.g., Underwriters Laboratories). Interconnection and equipment standards themselves are voluntary guidelines that establish basic procedures and minimum technical performance metrics for equipment and systems operating in parallel to (i.e., grid-tied) or in isolation from (i.e., stand-alone or off-grid) the power system. They are often adopted directly or modified as needed by regulators and utilities to form mandatory interconnection requirements and equipment requirements that comprise a broad set of grid requirements.

6.2.1 Interconnection Requirements and Underlying Relevant Standards

While requirements for interconnecting larger, grid-tied systems may be processed on a case-by-case basis, for smaller distributed systems, these requirements are often codified in technical requirement documentation known as interconnection requirements. Interconnection requirements are key mechanisms that utilities use to ensure safe and reliable interconnection processes when connecting new DERs (Nagarajan 2018). The requirements are primarily focused on the interface between DERs and the power system. DER interconnection requirements govern behavior related to:

- the operation of the DERs during normal grid operation;
- the response of the DERs during abnormal grid conditions;
- physical safety, maintenance practices, and cybersecurity protocols;
- the ability of DER to communicate through accepted protocols; and
- the interoperability of DER systems to streamline their operation and interconnection (Nagarajan 2018).

These requirements do not typically offer guidance on the operation or planning of the power system in the context of DERs.

DER interconnection requirements will typically establish a minimum standard of behavior for components related to specific actions to help maintain or re-establish system stability. For instance, a DER interconnection requirement may include a requirement dictating the minimum ability of a DPV-plus-storage system to absorb or inject reactive power into the electric distribution system or the ability to stay online during system disturbances. Often, DER interconnection requirements designate a range of latent capabilities that interconnecting systems must be able to provide, such as IEEE 1547's performance categories—ultimately, utilities (sometimes under the oversight of regulators) will choose to activate the capabilities and responses most appropriate for their power system context within a mandatory interconnection requirement.

Most DER interconnection requirements are to some extent underpinned by the voluntary industry standard IEEE 1547, the most recent of which was updated in 2018. IEEE 1547-2018, or *Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*, is a voluntary industry standard for DER interconnection that establishes criteria and requirements for interconnection of DER with electric power systems and associated interfaces (Horowitz et al. 2019; Nagarajan 2018). IEEE 1547 is generally technology neutral and refers to all DER connecting to the power system, including both grid-tied DPV and DPV-plus-storage systems. To meet IEEE 1547-2018, DER systems and their individual components must be capable of meeting all performance categories and communication protocols. In reality, some utilities and regulators that use IEEE 1547 as a basis for their interconnection requirement may select which of the latent capabilities to activate according to local power system characteristics and needs. Others may choose to adopt IEEE 1547 as their interconnection requirement wholesale—without any major modifications to the various design parameters.

6.2.2 Equipment Requirements and Underlying Relevant Standards

One of the most important aspects of guaranteeing the safety of utility line workers and the public more broadly is ensuring that all interconnected electrical equipment operates as required and is built to comply with relevant interconnection requirements and electrical codes. To ensure safety, electrical codes governing the construction of systems behind the utility meter (see Section 7), as well as interconnection requirements which govern interactions of DER with the power system, require electrical equipment be certified by a recognized testing and certification laboratory, such as Underwriters Laboratory in the United States, which promulgates electrical testing requirements and certifies equipment from various manufacturers. Equipment standards developed by such institutions typically consist of a series of testing procedures certifying that a specific piece of equipment undergoing certification is capable of behavior required by common interconnection standards. While interconnection standards, such as IEEE 1547, may dictate the behavior required from inverter-based systems and DERs interconnecting to the power system, the testing to certify that inverters are actually capable of such behavior is contained in a separate equipment standard known as UL 1741.[47]

Equipment precertification helps ensure that individual pieces of equipment and/or common combinations of equipment (e.g., solar panels, batteries, inverters, and/or other interface devices) are acceptable for continuous operation and interaction with the utility grid and can be reviewed and approved in a streamlined manner. While using precertified equipment can help to avoid costly or time-consuming equipment reviews and tests, this does not automatically qualify an interconnection application for approval—relevant screening criteria must still be implemented, and interconnection requirements must be complied with as well.

6.2.3 The Role of Regulators

IEEE 1547 and UL 1741 have been adopted in some form by the majority of U.S. states as binding interconnection requirements and equipment requirements. Yet, regulators in each jurisdiction have been faced with decisions on how exactly to adopt and incorporate them into their grid requirements, as these standards allow for some customization of desired DER behavior. Some U.S. regulators, often with a statutory mandate motivating them, have played a leading role in developing and implementing state-wide grid requirements.[48] Other regulatory bodies lacking statutory mandates, adequate staffing resources, and/or institutional capacity are frequently tasked with reviewing, modifying (if warranted), and approving utility proposals for grid requirements in public regulatory proceedings. In these circumstances, regulators may also provide broad guidance to utilities, such as to modify certain characteristics of particular standards.

Regardless of whether existing standards are adopted or modified, regulators also have an important role in ensuring that interconnection requirements are publicly available. Clear, transparent, and readily accessible grid requirements can ensure a smooth deployment of DPV-plus-storage systems by communicating to customers and installers acceptable equipment and systems (e.g., UL-certified). Furthermore, regulators often aim to ensure a consistency of interconnection requirements across various utilities operating under their jurisdiction. This

[47] Interconnection standards and equipment standards often develop in tandem or in response to one another.

[48] In the United States, in jurisdictions that have seen significant DPV and storage-plus-DPV deployment (e.g., Hawaii Rule 14H and California Rule 21—see Appendix A), regulators have chosen to play a more significant role in the development of standardized state-level interconnection requirements, whereas elsewhere regulators have adopted standards such as IEEE 1547-2003 and UL 1741 with little to no changes.

consistency can reduce administrative burden for installers by eliminating the need to learn multiple utility interconnection processes while doing business in a single regulatory jurisdiction (e.g., a state).

Importantly, regulations governing the grid requirements are not static, and regulators have an important role in determining when state and/or utility-specific requirements need to be updated in response to an evolving power system and market context. New technologies (e.g., behind-the-meter battery energy storage systems), improved capabilities (e.g., the ability for inverters to absorb and provide reactive power, even absent solar generation), and increasing levels of system deployments (which can exacerbate technical issues on the distribution system) are all reasons for updating existing equipment requirement and interconnection requirements. In the United States, updates to grid requirements have been driven primarily by:

- increasing penetrations of new inverter-based technologies and associated increases in bidirectional flow of power at the distribution level;
- the availability of improved communication and controls for DER systems; and
- the need for increased power system flexibility due to increasing levels of variable renewable energy generation (Nagarajan 2018).

As the number of DERs on power systems has grown, these systems are increasingly being required to play a larger role in maintaining power system reliability. For instance, the 2003 version of IEEE 1547 required distributed assets to trip offline during abnormal grid events and barred these assets from providing any sort of voltage regulation because there was little experience with significant levels of DERs on the grid system at this time. In 2014, IEEE 1547a was published, requiring DERs be capable of actively regulating voltage, providing improved frequency ride-through, and riding through a wide range of high and low voltage levels. The standard was again updated in 2018 with additional details and requirements, such as allowing, but not requiring, DER systems to provide inertial response (Horowitz et al. 2019).

6.3 Rules Governing Interconnection Application Technical Review Practices

The technical review practices that govern interconnection are reviewed below, including the DER technical screening process, distinctions for screening DPV-plus-storage, and U.S. examples.

6.3.1 Review of Distributed Energy Resource Technical Screening Processes

Interconnection applications are subject to a technical review process by utilities prior to interconnection to ensure that the proposed DER system will not interfere with the safe and reliable operation of the distribution system. This review involves the implementation of various technical screening criteria (often referred to as screens) through a structured process. Regulators will typically either directly promulgate these screening requirements, or review and approve utility proposals to do so, or some combination thereof.[49] These screens may either be developed by regulators and utilities themselves or may be adopted and adapted from model screens developed by other regulatory agencies, such as the U.S. Federal Energy Regulatory Commission (FERC) Small Generator Interconnection Procedures (SGIP).

Technical screening criteria, which are a series of technical questions about the proposed interconnected system, are intended to account for both the key operating parameters of the proposed interconnecting system as well as the actual conditions of the circuit to which the system intends to interconnect. Ultimately, these screens are designed to ensure that the level of review to which interconnecting systems are subjected is commensurate with their potential impact on the local distribution system. Technical screening criteria are typically framed in a technology-neutral format and often cover all generating facilities connecting to the distribution system, rather than grid-tied DPV systems or DPV-plus-storage systems independently. Thus, the same technical review process

[49] In more advanced jurisdictions, regulators have taken a more hands-on approach to the development of the interconnection review process, such as in California, where regulators intend to require utilities to use hosting capacity analyses (see Hosting Capacity Analysis text box) to further fast track interconnection applications.

used for grid-tied DPV systems should adequately cover DPV-plus-storage systems, with few modifications (discussed in the subsequent subsection).

Once an application for interconnection is received by the utility, there may be a series of initial application review questions to quickly determine if the system requires a more in-depth review or might immediately require a more detailed study. One important concern for utilities is whether or not the system uses precertified equipment, such as inverters certified under UL 1741 (see Section 6.2.2 for a discussion on equipment requirements and standards), which guarantees a minimum threshold of safety and ensures the system will behave in a reliable and predictable manner. Using precertified equipment is typically required for systems seeking expedited, or fast tracked, approval. Precertified equipment, however, does not guarantee fast track approval.

In practice, systems will still be subject to initial technical review screens, usually in the form of simple, binary yes-no questions and statements, which cover fundamental operational behavior of the system (e.g., “Aggregated DG does not cause protective device to exceed 87.5% of short circuit interrupting capability”). Importantly, DPV-plus-storage systems which are designed to not export to the distribution system may be subject to a lower number of technical review screens than exporting systems. For instance, Hawaii’s Rule 14H states that installing customers who participate in the Customer Self-Supply program—which does not allow grid exports—are exempt from 5 of the 10 initial technical review screens that exporting customers are subject to (HECO 2015a). [50]

In many technical review processes, proposed systems that do not satisfy these qualifications may be subjected to a series of more in-depth supplemental review screens. If the proposed system passes these supplemental screens, then it may still qualify for a fast-tracked approval.

Systems that fail both initial technical review screens and supplemental technical review screens will be subject to a detailed impact study to determine the extent of expected technical impacts and what mitigation measures, if any, can and should be taken before the system can be allowed to interconnect. These studies are typically paid for by the DER applicant and are only conducted if the DER applicant agrees to pay for the study. Impact studies, which can be performed by the utility themselves or be required from third-party groups, can be quite costly, especially relative to the cost smaller scale DER systems. Regulators are therefore often tasked with determining a fair and appropriate fee that utilities can charge or require of customers for their completion, as well as a reasonable time frame for completing the study.

[50] Other key distinctions for screening storage-plus-DPV systems will be discussed in Section 6.3.2.

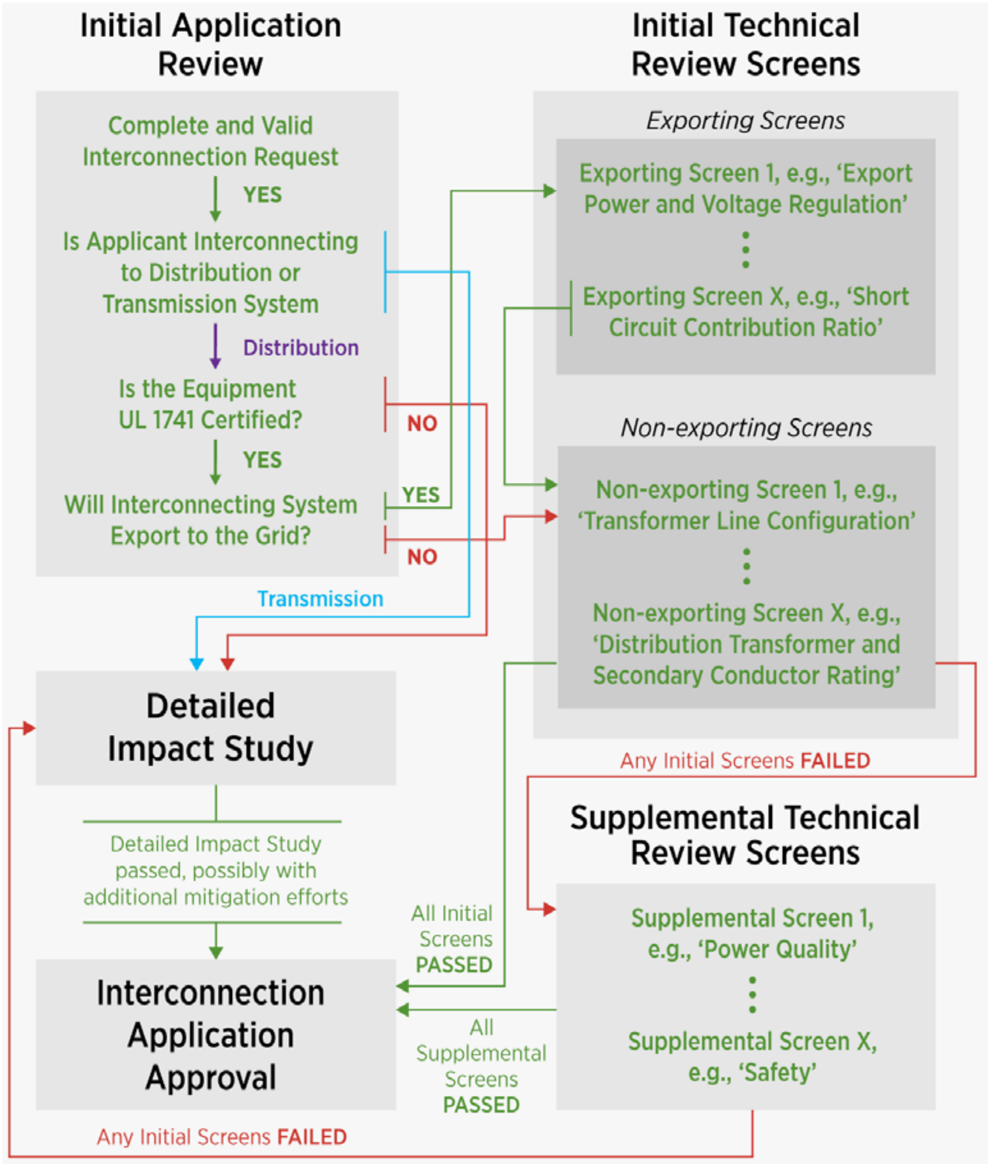

Figure 13. Overview of technical screening process for an interconnection application

Source: Original [*Illustration by Alfred Hicks, NREL]*

Managing a significant number of interconnection applications can become administratively burdensome for utilities, and subjecting each application to a detailed review may exhaust utility resources or cause application processing times to exceed regulated time limits. Categorizing interconnection requests through a series of increasingly more involved technical screens, as shown in Figure 13, helps reduce the administrative burden for utilities and average application times for customers without sacrificing the reliability of the power system. Furthermore, streamlining applications this way helps utilities focus their resources on reviewing proposed interconnections which are most likely to cause potential issues. Figure 13 depicts one example of the different levels of technical screens and how they interrelate and can ultimately lead to a detailed engineering study.

6.3.2 Distinctions for Screening DPV-Plus-Storage Systems

As mentioned previously, the same general technical review criteria and process used to evaluate grid-tied DPV systems can be used to evaluate DPV-plus-storage systems; however, there are a few key differences. Depending on the technical configuration, intended use case, and total export capacity of the DPV-plus-storage system, various changes to the technical screening process may be appropriate.

To begin, screening criteria are often implemented using the nameplate capacity of the DER; however, it may not necessarily be appropriate to use this metric for a paired storage and DPV system. For example, if a DPV-plus-storage system's control settings limited its ability to charge from or export to the grid (e.g., due to a technical configuration requirement), evaluating the combined nameplate capacity of the battery and DPV systems may be inappropriately rigorous, and the DPV system capacity could instead be used. In the event that the storage system undergoing review is allowed to export to the distribution system, it is increasingly common in the United States to use a capacity metric that reflects the maximum possible export of the combined DPV-plus-storage system rather than nameplate capacity. This metric is often based on the inverter nameplate size, or if multiple inverters are involved, a combined nameplate size, in kW or kVA. Utilities in states such as Minnesota, Nevada, North Carolina, and South Carolina are required to evaluate the interconnection requests of DPV-plus-storage systems based on their net system capacity (i.e., the maximum export allowed by the storage control system), rather than the nameplate capacity (i.e., the aggregate capacity of the battery and DPV system) (see Nevada's Rule 15) (Horowitz et al. 2019). Along similar lines, Colorado's Xcel Energy and NV Energy's interconnection guidance documents also discuss how the net capacity of storage systems can be reduced using programming and controls (Xcel Energy 2017; NV Energy 2018a).

At a high level, understanding the intended use and technical configuration of a DPV-plus-storage system can help utilities and regulators determine which capacity metric should be evaluated to avoid unnecessarily rigorous review processes. Carefully considering which capacity metric to evaluate for an interconnection application is particularly important for systems, which are designed not to export to the grid, as these systems are least likely to interfere with normal operations and could reasonably benefit from being subjected to less intense scrutiny (Peterson 2018; Horowitz et al. 2019). For instance, in Hawaii, customers who install DPV systems in configurations that preclude exports to the grid are eligible for expedited review processes (HECO 2019a).

Jurisdiction Examples

California—Rule 21 mandates the process and requirements for generation facilities to interconnect to the distribution system. Numerous revisions have been made over the years, including two recent revisions that clarify an expedited interconnection process for non-exporting storage and further explain the review process for evaluating load aspects of storage (an important factor in determining how costs are allocated if storage load triggers grid upgrades) (PG&E 2018). Currently, Rule 21 is under revision to include, among other updates, the incorporation of a hosting capacity analysis and power flow analysis known as the Integration Capacity Analysis tool to further streamline interconnection application processing (CPUC 2017b).

Nevada—Rule 15 clarifies that net, not combined, system generating capacity will be used to determine storage system sizes and the requisite rigorousness of interconnection review. Moreover, non-exporting storage are required to undergo supplemental testing procedures to ensure their control systems function properly and comply with inadvertent export restrictions (NV Energy 2018a).

Hawaii—Interconnection requirements address both non-exporting and exporting behind-the-meter DER systems in Hawaii, while also making special accommodations for retrofit storage systems (i.e., those added onto an existing DPV system) versus new-build systems. All exporting systems (e.g., those under Hawaii's Smart Export Program) follow the standard interconnection process (which includes provisions for evaluating storage capacity and exported power) (HECO 2015a, 14; 2018, 25). New-build, non-exporting systems fall under Hawaii's Customer Self Supply program and are subject to a reduced number of technical screening criteria relative to exporting systems. Non-exporting storage retrofitted to an existing, exporting NEM-approved DPV must register with the utility but generally bypass technical reviews (Peterson 2018); however, regulations state that "the total export capability must be limited to the size of the original NEM system," and advanced inverter requirements must be met (Hawaii PUC 2018, 33). If a customer chooses to add additional DPV capacity and storage to an existing NEM account, they would fall under Hawaii's NEM Plus program—provided that the original export capacity for which they have already been approved under the NEM program is not exceeded, they are subject to the less rigorous Customer Self Supply screening procedure.

Hosting Capacity Analysis

DER hosting capacity is the total DER capacity that can be accommodated on a given distribution feeder, without any feeder upgrades or modifications, before adverse impacts to critical operational parameters (such as voltage, frequency, power quality) begin to manifest (Ding, Mather, and Gotseff 2016). Hosting capacity is an important parameter for utilities that clearly communicates whether a feeder is in danger of experiencing abnormal operation due to the presence of DERs. This metric is often displayed using distribution feeder maps that indicate the DER capacity that can be accommodated at specific locations throughout the distribution system. This metric and associated maps can help utilities quickly categorize interconnection applications based on the local conditions of the feeder to which the proposed system intends to interconnect. The hosting capacity of a feeder is not static and can change in response to many factors, such as how the various interconnected DERs are being operated, the presence of mitigating measures and equipment, or the consumption patterns of customers present on the feeder. For instance, the increased supporting role of DER that is enabled when the IEEE 1547-2018 standard is adopted can increase the DER hosting capacity of feeders by allowing smart inverters to mitigate potential voltage issues caused by PV arrays (Nagarajan 2018).

DER hosting capacity analyses use power flow studies to determine the maximum level of installed capacity of a particular technology that a feeder can support without interfering with normal grid voltage, protection coordination, and other essential quantities. These analyses can function as important tools for utilities to help accurately and quickly determine whether a proposed system (such as storage-plus-DPV) will negatively impact grid operations based on system and feeder specific characteristics (system capacity, number of customers on the feeder, intended use case of the system, and so on).

In some jurisdictions, regulators have begun incorporating these metrics and studies into the interconnection process to streamline application processing times while increasing the technical rigor of screening criteria. In California, regulators are currently revising their interconnection process to require utilities to periodically conduct hosting capacity analyses as a part of their standard technical screening process (CPUC 2017b). Utilities will be required to supply periodically updated hosting capacity maps to developers, which can help developers target their installations in areas where interconnection is least likely to require expensive mitigation efforts. This can lead to less administrative burden for utilities tasked with processing these applications, as well as faster and less expensive interconnections for customers and developers. (To explore one of these maps for SCE, see this guidebook: https://www.sce.com/sites/default/files/inline-files/DERiM_User_Guide_Final_AA_0.pdf, or visit this website: https://ltmdrpep.sce.com/drpep/.)

In Hawaii, the Hawaiian Electric Companies are required to provide circuit-level hosting capacity analysis for all islands in the Companies' service territories, and to make that information publicly available. Locational Value Maps, found on the Companies' website, for Oahu, Maui County, and Hawaii Island indicate the approximate amount of DPV currently on the utilities' primary distribution network, as well as the available remaining total capacity output available for customers to connect DPV to the grid based on the hosting capacity of the primary circuit and service address location. Maps can be accessed at https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/locational-value-maps.

7 Step V: Consider Local Permitting Issues

While not directly responsible for them, regulators may need to account for the presence of local permitting processes and compliance with relevant electrical codes within interconnection processes for DPV-plus-storage deployment.

In the United States, local jurisdictions issue construction and building permits for DG systems as part of their requirement to ensure safety, public health, and general welfare as it relates to buildings and construction—in the electric utility sector in the United States these local jurisdictions are sometimes referred to as the authority having jurisdiction (AHJ). AHJs issue permits that recognize compliance with relevant electrical and fire codes adopted by the jurisdiction and signal to the utility that a DER system can be permitted to operate, provided it has successfully complied with the relevant grid requirements (for an overview of the entire interconnection and permitting process, see Figure 12 in Section 6). In the United States, the main electrical code adopted by jurisdictions is the National Electrical Code (NEC), which covers all elements relevant to the safe and secure installation of electrical equipment and electrical wiring (see Appendix A). Where interconnection and equipment standards specify the desired operation of the DER, the NEC provides guidance on how to safely install and wire a DER system.

With the increasing deployment of DPV systems, many local governments have increasingly adopted streamlined permitting procedures, and have gained familiarity with issuing permits for DPV systems. Few, however, have experience permitting behind-the-meter battery storage systems, leading to inconsistent permitting processes and fees across jurisdictions. Understanding if and how the permitting processes of stand-alone storage and/or DPV-plus-storage systems differ from grid-tied DPV system permitting processes may be increasingly important as battery prices continue to decline and businesses and residents begin to deploy these systems at-scale.

To address this information gap, California passed Assembly Bill 546 in September 2017, directing California cities and counties to make storage permitting procedures and applications publicly available online and accept applications electronically. Additionally, the bill instructed the Governor's Office of Planning and Research (OPR) to educate communities and local governments on storage permitting and inspection best practices (California State Legislature 2017). Energy storage workshops held in 2018 informed the development of an energy storage guide that California's OPR plans to issue in 2020 (Governor's Office of Planning and Research 2019). In the meantime, OPR offers communities a curated online repository of energy storage resources. In their 2017 *Final Report on Policy Recommendations and Guidelines for Permitting Energy Storage* prepared for the California Energy Commission, various stakeholders recommended the use of a standardized, streamlined, and expedited energy storage permitting processes across California jurisdictions largely based on existing small-scale PV system permitting processes, plus additional training for contractors (Sovereign Energy and Clean Coalition 2017).

Like California, New York has been a first mover in the establishment of storage permitting best practices. For example, in April 2018 the New York State Energy Research and Development Authority, in partnership with the Smart Distributed Generation Hub, ConEdison, and various New York City departments, published the *Energy Storage System Permitting and Interconnection Process Guide For New York City Lithium-Ion Outdoor Systems*, outlining how different sizes of outdoor storage systems should be treated in the unique, dense, urban environment of New York City.[51] The New York State Energy Research and Development Authority also plans to issue guidance on storage siting outside NYC and in indoor settings (McAllister et al. 2019). In both California and New York, the development of local permitting best practices, guidelines, and resources for battery energy storage systems has been and continues to be a multi-stakeholder-driven process that considers fire, electrical, and building codes and standards.

As penetrations of DPV-plus-storage systems increase, the need for clear, standardized guidance pertaining to battery safety issues will become more pressing. Equipment requirements apply to all aspects of energy storage systems, from the design and construction of small parts of the energy storage system (e.g. wires, switches) to how system components (e.g. inverters) work together, and codes dictate how systems are integrated into the built environment (Conover 2014). Many storage technologies have spatial sensitivity (where they are allowed to be

[51] It should be noted that this guide only offers guidance for outdoor systems, due to the New York City Fire Department's concern about siting lithium-ion battery systems indoors.

installed) and temperature sensitivities where cooling or heating may be required so they perform safely during all times and during all seasons (Akhil et al. 2013; Byrne n.d.). Particularly in the case of batteries, these new installations can pose fire hazards for system owners, first responders, utility employees, and system installers.

Ongoing NREL-led research tested battery performance characteristics under different environmental conditions using NREL's Energy System Integration Facility's testing chambers. Results indicate that lithium-ion batteries de-rate significantly at high temperatures and shut down entirely upon reaching 115° F/46° C, as aligned with relevant equipment standards. This temperature-induced shutdown reduces safety concerns (e.g., fires, explosions) due to thermal runaway, but does demonstrate that temperature can impose operational constraints that utilities and customers should be aware of from both technical and economic perspectives.

Safety codes and regulations can help ensure DPV-plus-storage systems will perform as expected, regardless of environmental conditions, and not degrade due to improper installation, operation, or transportation. Building and fire codes, like those adopted in California (see the text box below) and New York (as previously discussed), address indoor and outdoor storage systems' safety concerns separately given different environmental conditions and risks. Important features called out in building and fire codes include spacing, security (e.g., fencing for outdoor systems), placement of electrical disconnects and emergency stops, construction building or encasement material (e.g., noncombustible), fire suppression systems, and ventilation and exhaust systems. Appendix A includes some major standards and codes in the United States, covering the testing, performance, and installation of DPV-plus-storage systems installed behind-the-meter, but the list is not exhaustive. Policymakers in their respective countries can assess if and how their safety codes address behind-the-meter battery storage and what additions, or adjustments may be needed for this technology.

Fire Codes and Market Implications for Storage-Plus-DPV Systems

Sometimes codes and standards must be adapted to cater to the characteristics of emerging energy technologies, as in the case of behind-the-meter lithium-ion batteries. When governments are slow to adapt, this can create confusion for developers and impede deployment until stakeholders have time to understand and adapt to new rules. For example, the California Building Standards Commission adopted a state fire code revision in July 2018 that places more stringent spacing and fire suppression requirements on indoor and outdoor lithium-ion batteries 20 kWh or greater (previously 250 kWh or greater) (GTM 2018). This new requirement is adopted from the recently released National Fire Protection Association (NFPA) 855 "Standard for the Installation of Stationary Energy Storage Systems" that will go into effect in 2020 (Hyde 2018). These new regulations have caused concerns and project delays from developers and led some market analysts to decrease their 2019 and 2020 nonresidential battery deployment forecasts for California (GTM 2018).

8 Policy and Market Context for DPV-Plus-Storage

Regulatory decisions are made in the broader context of a policy and market environment. This policy and market context influences all other steps in the decision-making process. The following section provides a brief overview of various policy, market instruments, and approaches that may have relevance for DPV-plus-storage systems.

These include, among others:

- Storage Deployment Mandates (Section 8.1)
- Nonbinding Storage Goals (Section 8.2)
- Renewable Portfolio Standards and Clean Peak Standards (Section 8.3)
- Direct Financial Incentives (Section 8.4)
- Distribution Network Service Provision (Section 8.5)
- Wholesale Market Participation (Section 8.6)
- Distribution Market Structure
- Distribution Company Performance Standards

The latter two points are beyond the scope of this report, but have important implications for financing, investment, ownership, and operation and maintenance of DPV-plus-storage projects, as well as the fostering of competitive markets where new service providers have access alongside incumbent distribution utilities.

8.1 Storage Deployment Mandates

Governments can directly require utilities to procure specific levels of behind-the-meter storage capacity using deployment mandates. Most U.S. storage-related mandates to date have been stated in terms of total power capacity (kW) or energy capacity (kWh). Utilities may be subject to a single target or a series of consecutive, graduated targets over time.

For ensuring desired outcomes with storage-only or DPV-plus-storage deployment mandates, governments can consider specifying who is allowed to own eligible behind-the-meter storage systems. Should utilities be allowed to own these customer-sited assets, or can eligible third parties and/or customers be allowed to own them as well? Regulatory guidance to utilities on acceptable procurement mechanisms for behind-the-meter storage can help to reduce regulatory uncertainty and ensure utility buy-in for the mandate.

Jurisdiction Examples

California—In October 2013, in response to Assembly Bill 2514, the California Public Utility Commission issued Decision 13-10-040, which mandated their three investor-owned utilities (IOUs) to procure 1,325 MW of storage by 2020 (CPUC 2013). The bill also created interim, graduated storage mandate targets for each of the IOUs for 2014, 2016, and 2018. Furthermore, the storage mandate targets were divided between three different "grid domains," or points of interconnection (transmission, distribution, and behind-the-meter), with 200 MW of storage required to be behind-the-meter.

The California IOUs are allowed to defer up to 80% of their required storage capacity to later procurement periods and are allowed to shift up to 80% of their required storage capacity between the transmission and distribution grid domains, although no target shifting is allowed for customer-sited storage. This flexibility and graduated targets should allow the IOUs to align the storage mandates with their actual territories needs and to make the most economically efficient investments. The IOUs are furthermore allowed to own up to 50% of all the storage capacity across all three grid domains, including behind-the-meter systems (CPUC 2013).

For ensuring utility compliance with the deployment mandate, California utilities can use a range of mechanisms, including: (1) count customers for compliance who installed storage systems independently in response to existing incentive programs and compensation mechanisms; (2) create regulated utility programs that involve direct utility ownership of customer-sited storage systems; (3) create regulated utility programs which involve private ownership of customer-sited storage systems, where financial incentives are offered to grant the utility control over the storage system; and (4) conduct a competitive procurement for grid services from aggregated customer-sited storage systems to which third parties and aggregators can respond.

8.2 Nonbinding Storage Goals

In addition to setting binding deployment mandates, jurisdictional authorities can also set aspirational or nonbinding goals for utilities to reach. Instead of including punitive measures to incentivize procurement, policymakers can attempt to remove barriers to deployment or provide additional funding. Some U.S. states have instituted nonbinding storage goals.

Jurisdiction Examples

New York—In 2018, the governor of New York established a nonbinding goal of 1,500 MW of storage by 2025 and 3,000 MW by 2030. The goal directs New York's relevant regulatory bodies to remove barriers to the adoption of storage and signals a strong future for storage to potential developers. The target does not differentiate between stand-alone storage or PV-paired storage, or larger front-of-the-meter installations and behind-the-meter installations. While not directly incentivizing DPV-plus-storage systems, many of the changes to policy and regulations which may stem from the target, such as streamlining interconnection processes or fire-safety approvals may nevertheless be valuable for encouraging such installations (NYPSC 2018a).

In addition to the target, the New York Independent System Operator (NYISO) explicitly allows the aggregation of behind-the-meter batteries to facilitate their participation in the wholesale energy market, which could open up an important revenue stream for DPV-plus-storage systems in the near future, and allows for dual participation of such systems in retail and wholesale markets (NYISO 2017).

Massachusetts—In 2017, the Department of Energy Resources adopted an aspirational target of 200 MWh for distribution companies to procure by 2020. As with New York, this aspirational goal fits into a larger plan, the Energy Storage Initiative, which provides funding for rebates and studies, and recommends regulatory changes to help distribution companies achieve the targets (DOER 2017).

8.3 Renewable Portfolio Standards and Clean Peak Standards

Renewable portfolio standards (RPS) are obligations regulators impose on utilities that require a certain level of energy used to meet demand or a certain level of generating capacity in a utility territory come from qualifying resources. Clean Peak Standards (CPS) are a relatively new variation on RPS and mandate that a certain portion of peak demand or net peak demand be met using renewable energy sources.[52] These policies reflect a growing interest by policymakers and regulators to reduce the magnitude of peak demand and/or supply clean electricity to meet peak demand, as opposed to using conventional peaking capacity (e.g., open cycle gas turbines) that is typically expensive and less clean to operate.

In RPS or CPS schemes, a trading platform or registry creates, issues, and finally retires tradable certificates, which represent the renewable or clean aspect of a MWh of generation from qualifying resources. Regulators use these certificates to track compliance with the RPS or CPS. These certificates are awarded to eligible generators who can then sell them to complying entities, such as distribution utilities, who in turn use the certificates to meet their RPS or CPS obligations, which are determined by regulators. When a utility surrenders their acquired certificates, the certificates are retired to prevent the same certificate from satisfying the requirements of multiple power purchasers.

Under an RPS, qualifying generators are awarded renewable energy certificates for any generation that is injected to the grid. Under a CPS, qualifying generators are awarded clean peak certificates for any generation exported to the grid during a CPS compliance window. This compliance window is set well in advance of the initiation of the CPS program, usually concurrently with the establishment of the annual minimum generation percentage target.

While these policy tools are generally focused on incentivizing the deployment of utility-scale renewable generation assets, they can be adjusted to also include distributed assets and storage. RPS have already been

[52] Net demand can be defined as the total electricity demand in a power system minus variable renewable energy generation. It represents the electricity demand that must be met by non-variable renewable energy resources, such as fossil-fuel resources, hydropower or nuclear energy. Net peak demand is the maximum value that net demand exhibits in a given period.

expanded to incentivize DG deployment through the use of special carve-outs in the RPS or credit multipliers for DG resources, and it is plausible these elements in an RPS or CPS could be similarly used to incentivize storage and DPV-plus-storage deployment (Donalds 2017; Holt and Olinksy-Paul 2016). While credit multipliers could be used to incentivize the pairing of DPV and storage, they also could have the effect of lowering the overall level of desired clean energy capacity that is procured to satisfy the RPS or CPS, and thus should be considered carefully.

Even without the presence of credit multipliers or carve-outs, a CPS could incentivize the pairing of solar and storage by creating an additional value stream for storage systems. This is particularly true if the CPS compliance window occurs outside solar generation hours and can be used for either distributed or centralized systems. Under a CPS, storage could help DPV systems qualify for certificates by shifting renewable energy generation to meet peak demand, and net peak demand in particular (Burgess and Olinsky-Paul 2018).

As storage cannot generate electricity in and of itself, it is important to prevent accounting errors (e.g., double counting) of qualifying energy generation to ensure REC and CPS integrity. Generally, there are three cases when ensuring renewable energy certificate and CPS integrity: (1) the storage can charge from multiple sources, and the generation into the storage system is known; (2) the storage can charge from multiple sources, but the generation into the storage system is not known; and (3) the storage can only charge from an eligible generating source. In the first case certificates can be issued based on the generation mix used to charge the storage system. In the second case, certificates may only be issued to the generating resources, which would not incentivize storage. In the third case, certificates can be issued based on the generator or storage output. When certificates are based on the generator, this would ignore round-trip losses in the storage system; however, when certificates are based on storage output, the generator would be effectively taxed for those losses even though the grid may benefit from the use of storage to shift generation (Holt and Olinksy-Paul 2016).

Jurisdiction Examples

Massachusetts—In July 2018, the Massachusetts House passed the Act to Advance Clean Energy, which required the Department of Energy Resources to establish a CPS and a minimum share of energy sales to customers, which must come from clean peak resources (defined as a qualified clean energy resource, storage system, or demand response resource that generates or discharges energy to the power system, or reduces load, during a seasonal system peak period). This minimum share of energy sales would increase by 0.25% per year thereafter (Golden et al. 2018). According to draft regulations, storage is qualified for accreditation under the CPS as long as it can prove that it operates primarily to store and discharge renewable energy through one of the following conditions (Baker et al. 2019):

1) The storage system is collocated with a renewable generation resource;

2) The storage system is contractually bound with a non-collocated renewable generation resource; or

3) The storage system charges coincident with designated Qualified Energy Storage System charging periods, shown in Table 4.

Table 4. Qualified Energy Storage System Charging Windows by Renewable Energy Source		
	Energy Storage Charging Windows	
Clean Peak Season	Solar-Based Charging Hours	Wind-Based Charging Hours
Winter	10 a.m.-3 p.m.	12 a.m.-6 a.m.
Spring	8 a.m.-4 p.m.	12 a.m.-6 a.m.
Summer	7 a.m.-2 p.m.	12 a.m.-6 a.m.
Fall	9 a.m.-3 p.m.	12 a.m.-6 a.m.

Adapted from: Baker et al. 2019

For Massachusetts, the Clean Peak compliance window will be redetermined at least every 5 years based on changes in the state's load shape, but has been determined to coincide with net peak demand. The compliance window changes for each season and will initially be: Spring, March 1-March 14 from 5 p.m. to 9 p.m.; Summer, May 15-September 14 from 3 p.m. to 7 p.m.; Fall, September 15-November 30 from 4 p.m. to 8 p.m.; Winter, December 1-February 28 from 4 p.m. to 8 p.m.

Arizona—In October 2018, a commissioner for the Arizona public utility commission introduced an Energy Modernization Plan, which set forth several targets, including 80% clean energy by 2050, a 3-GW storage mandate by 2030, rules for promoting electric vehicle growth, and a CPS starting at 1.5% and increasing by 1.5% every year thereafter (Tobin 2018). The plan has not yet been finalized as of the time of this report's writing.

Washington—In 2013, the Washington legislature introduced a bill, which ultimately was not adopted, to modify the state's RPS to include credit multipliers for qualifying generating systems combined with energy storage. The bill would have allowed utilities to count electricity from energy storage facilities at 2.5 times the normal rate if the facility was "capable of storing energy from an eligible renewable resource during off-peak hours and dispatching the energy as electricity to an electrical transmission or distribution system during peak hours" (Morris et al. 2013, 6).

8.4 Direct Financial Incentives

In addition to changes to tariff structures or mandates, policymakers can create financial incentives, which can help customers meet the upfront capital costs involved in purchasing DPV-plus-storage systems and improve their return on investment. Financial incentives are either direct (i.e., cash) or tax-based. Tax-based incentives can be production-based (i.e., tax credit for every kWh of renewable energy produced), investment-based (e.g., tax credit equal to a fixed percentage of eligible project costs), or tax exemptions (i.e., eliminate or reduce a specific tax). Tax credits reduce the overall lifetime cost of a DPV-plus-storage project by reducing the taxes that the owner of a project owes its government.

Direct financial incentives are typically either upfront cash incentives or production-based cash incentives. Upfront rebates reduce the initial cost of installing a DPV-plus-storage system while performance-based rebates provide ongoing payments to a system owner based on the system's actual kWh production. Upfront rebates are typically expressed on a per-watt basis (e.g., $1.00/watt). The value of these incentives tends to fall over time when certain installed capacity targets are reached or in parallel with declines in market costs for DER projects. Participation rebate programs can be limited to systems which share certain characteristics (e.g., system size limits, technical configurations) or which agree to certain behaviors (e.g., data sharing, self-consumption only).

Jurisdiction Examples

California—California's Self-Generation Incentive Program provides rebates for qualifying energy systems, including battery energy storage systems. [53] To be eligible for the funds, qualifying systems must: (1) be connected to the local utility's distribution system on the customer's side of the meter; (2) be configured to run in

[53] http://www.cpuc.ca.gov/sgip/

parallel with the grid; (3) be a permanent installation for the useful life of the system; (4) be capable of discharging at rated capacity for a minimum of 2 hours; and (5) discharge fully at least 52 times per year. Of the total program budget, 75% is reserved for storage with the rest devoted to generation technologies; furthermore, 15% is reserved for projects with a capacity less than or equal to 10 kW. The program consists of a series of declining incentive rates ($/kWh) for storage systems and allots a maximum budget to each incentive rate. When the budget for the largest incentive rate is exhausted, the succeeding systems are offered the next largest incentive rate. Thus the limited 'budget bins' act as a spending cap for the entire rebate program. Table 5 shows how the allotted budget for each eligible storage type changes as the program progresses through the steps when the previous step's budget is exhausted. It also outlines the step-down in incentives for each step. Although the budget is allotted on a lottery basis, priority is given to projects which would have additional grid benefits or reduce greenhouse gas emissions (CPUC 2017a).

Table 5. California Small Generator Incentive Program Budget and Incentive Levels

		Step 1	Step 2	Step 3	Step 4	Step 5
Large Storage (> 10kW)	Budget*	$ 42,728,094	$ 102,959,451	$ 75,890,956	$ 75,890,956	$ 32,046,071
	Incentive	0.50 ($/Wh)	0.40 ($/Wh)	0.35 ($/Wh)	0.30 ($/Wh)	0.25 ($/Wh)
Large Storage Claiming ITC (> 10kW)	Budget*	$ 42,728,094	$ 102,959,451	$ 75,890,956	$ 75,890,956	$ 32,046,071
	Incentive	0.36 ($/Wh)	0.29 ($/Wh)	0.25 ($/Wh)	0.22 ($/Wh)	0.18 ($/Wh)
Residential Storage (≤ 10kW)	Budget	$ 7,540,252	$ 14,232,625	$ 10,526,843	$ 10,526,843	$ 5,655,189
	Incentive	0.50 ($/Wh)	0.40 ($/Wh)	0.35 ($/Wh)	0.30 ($/Wh)	0.25 ($/Wh)

*Note: the budgets for Large Storage with and without the ITC are shared.

Adapted from: SCE et al. 2017; CPUC 2019

Arizona—Starting in May 2018, Arizona utility Salt River Project began offering a $150/kWh-DC rebate, up to $1,800 for residential customers who installed a qualifying battery storage system and agreed to participate in their battery study. The program is available for three years or up to a program cap of 4,500 customers if they choose to participate. Only lithium-ion batteries certified to UL 1973 or UL 9540 are eligible. The study will focus on how customers use battery systems, how battery systems perform in Salt River Project's environment, and how residential battery systems affect the operation of the grid (SRP 2018).

Arizona Public Service also announced a Storage Rewards program in September 2018 that provides residential customers a one-time $500 bill credit for allowing Arizona Public Service to site a behind-the-meter storage system in their residence and grant APS control over the asset. The pilot program will help Arizona Public Service understand how behind-the-meter storage can support peak demand management (APS 2018c).

Massachusetts—As part of its Energy Storage Initiative, the Department of Energy Resources (DOER) has suggested the implementation of a rebate, Massachusetts Offers Rebates for Storage Program, known as "MOR-Storage," for behind-the-meter storage projects at commercial and industrial businesses. The $20 million grant will be available for both stand-alone storage and for storage paired with on-site solar PV generation. In addition to requirements on cost sharing, eligible projects must be able to demonstrate that the storage is providing a service that benefits all consumers, such as reducing on-site peak demand and that the project is capable of dispatching in response to local distribution system needs (Customized Energy Solutions et al. 2017).

In addition to rebates for select projects, Massachusetts also provides a financial incentive for DPV-plus-storage systems through the Solar Massachusetts Renewable Target (SMART) program.[54] Through this program, DPV owners receive payments for solar energy produced at a fixed $/kWh rate. Systems can also qualify for NEM credits, and the total compensation amount is the difference between the original SMART compensation and the NEM compensation to prevent double-counting. The SMART incentive rate is based on a declining block design wherein customers receive a set compensation rate up until a program cap is reached, after which the compensation rate is reduced for new applicants. In September 2018, the DOER clarified the eligibility of storage systems to participate in the SMART program. Storage systems co-located with solar installations which meet requirements on minimum efficiency, minimum/maximum nominal rated power, minimum/maximum nominal useful energy, and data provision can qualify for an Energy Storage Adder to the existing SMART rate, which applies to the level of solar generation of the paired system. Behind-the-meter installations which can meet the physical and operational requirements can also qualify (DOER 2018).

Nevada—In response to Senate Bill 145, NV Energy released an energy storage incentive program in September 2018. Customer eligibility, system size requirements, and incentive levels ($/watt-hour) vary by customer category (i.e., residential, small commercial, large commercial, low income/nonprofit, public entity). All eligible systems must be capable of being charged 75% by renewable energy sources. Customers on TOU rates receive a higher maximum incentive rate than non-TOU customers; similarly, commercial customers in a "critical infrastructure" area receive a higher rate than those in a noncritical infrastructure area. For all customer categories, incentive levels "step down" to a lower rate each time $1 million USD in incentives has been disbursed, with $5 million reserved for program funding across all customer categories (NV Energy 2018b). Thus, as with California's SGIP, the allotted budget functions as a program cap to ensure cost containment.

8.5 Distribution Network Service Provision

Utility DER-aggregation programs and pilots are typically intended to provide load control and demand response services to the local distribution system, as opposed to the wholesale market (Cook et al. 2018). In these more common use cases, distributed resources are either aggregated directly by the utility or by third parties, which then interface with the utility as a single resource to provide valuable services to the distribution system, such as congestion management. Similar to aggregated resources participating in wholesale energy markets, these resources must have the ability to receive and respond to signals, as well as relay their operational decision to respond back to the utility or third-party aggregator.

In addition to technical barriers to optimizing battery operations for the provision of multiple services, such as immature communication or battery control technologies, there can also be market and policy barriers to this kind of value stacking for stand-alone battery storage and DPV-plus-storage systems. Several of these potential market and policy issues are highlighted in the Market and Policy Barriers to Value Stacking text box.

Market and Policy Barriers to Value Stacking

In addition to the technical barriers to value stacking, there are several market and policy barriers which may prevent distributed storage-plus-DPV systems from providing multiple system services. First, in order to profit from providing a system service, these services must be valued either through markets or other mechanisms. Currently in many power systems, services such as governor response or black-start are not valued, and are instead required as a prerequisite to interconnection without opportunity for compensation. Second, even if system services are compensated, batteries and other distributed resources may not be fairly considered for service provision as they are relatively new and utilities are unfamiliar with the technologies. Finally, in some jurisdictions, systems may be barred from receiving compensation from both wholesale markets (for services like frequency regulation) and cost-of-service arrangements (Bhatnagar 2013). Regulators have an important role in clarifying that DERs are allowed to provide certain system services and ensuring that they are both adequately compensated for services provided as well as fairly considered for service provision in the first place. These considerations must be balanced with utility concerns to ensure that the provision of certain services from batteries and storage-plus-DPV systems does not compromise the safe, reliable operation of the power system.

[54] For additional information on Massachusetts' initiative, visit: https://www.mass.gov/info-details/solar-massachusetts-renewable-target-smart-program

Jurisdiction Examples

Hawaii—In 2014, as a part of DOE- and U.S. Navy-funded Energy Excelerator program, the utility (Hawaiian Electric) and battery operator (Stem) began installing behind-the-meter storage and storage-control systems. These systems were located on 29 commercial sites on the island of O'ahu, reaching a total installed capacity of 1MW by 2017. Using advanced software control, weather forecasts, and historical and real-time load data, these storage systems can be deployed to help commercial entities reduce peak demand usage, leading to larger bill savings for customers. The storage controls also allow Hawaiian Electric to aggregate these systems into 'virtual power plants.' The utility can call upon the virtual power plants in order to manage variations in solar PV output or other disturbances on the distribution system, allowing Hawaii to integrate increasing levels of renewable energy resources (HECO 2017; 2015b). Although all of these projects were stand-alone storage units, with advanced system controls, the same principle could be extended to DPV-plus-storage systems.

New York—As a part of the Reforming the Energy Vision initiative, the New York Public Service Commission directed its major IOUs to create demonstration projects which would "inform regulatory changes, rate design, and the most effective means to integrate DER on a larger scale" (NYPSC 2015, 118).[55] In response to this directive, the utility New York State Electric and Gas proposed and began implementing its "Aggregated Behind the Meter Energy Storage" demonstration project, which seeks to "demonstrate some of the value streams that can be leveraged in parallel by behind-the-meter battery storage and attempt to identify new value streams … [and] evaluate potential alternative rate designs and their impact on the value proposition of aggregated behind-the-meter battery storage" (NYSEG 2018, 3). Among other goals, the demonstration project seeks to prove that commercial and industrial customer storage systems can aggregate into a virtual power plant to reduce distribution circuit and system peaks. The demonstration project will install a mixture of small to larger battery systems at eight customer sites for a total of 1.06 MW and 4.2 MWh of battery storage capacity. By 2021 the utility hopes to be able to show, through data from metering equipment installed as part of the project, that the systems were able to reduce circuit peak during times of system-wide peak. Actual targets for circuit peak reduction will be determined once the customers have been chosen and the systems installed.

Vermont—Through its Resilient Home program, utility Green Mountain Power in Vermont offers its customers Tesla Powerwall batteries for $15/month, which customers can use to store excess solar power or to provide backup power during outages, in exchange for the ability to discharge the batteries to reduce its distribution system's peak demand. Customers can also enroll in the program without leasing the battery pack through the utility's Bring Your Own Device program, where they receive a fixed monthly bill credit from Green Mountain Power for their participation.[56] As of August 2018, the utility had more than 600 customers in the program and used the distributed solar-plus-storage systems to reduce demand during the summer peak periods, saving customers an estimated $500,000 in 2017 and $600,000 in 2018.[57]

8.6 Wholesale Market Participation

One large potential source of income for utility-scale battery storage systems is the provision of peaking capacity and ancillary services in wholesale electricity markets (Denholm 2019). Regulatory barriers to utility-scale storage systems in U.S. markets are being addressed with implementation of FERC Order 841, which stipulated that regional transmission organizations and independent system operators must revise their tariffs to allow for a 'storage participation model' that would facilitate storage's entry into the regional transmission organizations/independent system operators markets (FERC 2018b). The FERC order explicitly declined to expand the order's applicability to behind-the-meter storage that did not inject power to the grid and set a minimum size requirement for market participation of 100 kW.[58]

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[55] All demonstration projects can be found at: https://rev.ny.gov/rev-demo-projects-1.

[56] https://greenmountainpower.com/product/powerwall/.

[57] https://greenmountainpower.com/news/gmp-beats-new-peak-delivers-bigger-customer-savings-with-growing-network-of-stored-energy/.

[58] FERC argued that behind-the-meter storage systems which did not inject power into the grid were adequately covered under existing rules for demand response. The FERC order did not explicitly set the minimum size requirement to 100 kW, but rather required RTOs and ISOs to establish their own minimum size requirement that did not exceed 100 kW. Although FERC did not explicitly focus on behind-the-meter storage, barriers to smaller batteries could be similarly removed.

Minimum size constraints—which are intended to streamline power system operation in wholesale energy markets—prohibit most behind-the-meter storage systems and DPV-plus-storage systems from direct participation in wholesale power markets by themselves, in particular for systems sited with residential customers.

The aggregation of smaller DERs into a larger "virtual" resource can help smaller plants still participate in the wholesale market despite the minimum size constraints. In these use cases, DERs are typically aggregated by a private market participant. This aggregating entity is responsible for ensuring that smaller resources have the ability to receive signals, modify their operations as needed, and communicate their operational pattern to relevant entities.

The aggregation of DER for wholesale market provision may raise concerns over operational impacts to the distribution system, especially at the feeder level. Resources on the distribution system responding to signals to provide regulation services to the bulk-power system, for example, may increase feeder peak load or drastically impact voltage at the feeder. This is particularly true for energy storage which can both charge and discharge, potentially impacting voltage at the feeder in both directions (FERC 2018a). Despite these challenges, efforts are under way in several markets to enable smaller individual resources to be aggregated into larger systems for wholesale market participation.

Jurisdiction Examples

California—In 2016, CAISO modified its tariff structure to allow aggregated DERs, including behind-the-meter battery storage, to participate in its independent system operator market to provide both energy and ancillary services (California ISO 2016).

In 2015 PG&E, an investor-owned utility, started the Supply Side DR Pilot, which was designed to study aggregated resources' ability to supply a proxy demand resource product in the wholesale market (Anderson and Burrows 2017; California ISO 2010). A proxy demand resource is defined as "a California Independent System Operator market product where retail customer loads are bid in to the CAISO's wholesale energy market for purposes of demand response. A PDR can be one or more retail customer accounts that have been entered as a single resource into the CAISO's demand response system by a demand response provider." Systems from five third-party aggregators successfully provided both customer-facing services (e.g., demand charge reductions) and bulk-power system services (California ISO 2010). The pilot was updated and continued in 2017 to help provide local distribution services in addition to customer-facing and bulk-power system services (PG&E and Olivine 2017).

Regulators in California have also pioneered the development of market rules surrounding value stacking issues for batteries. Specifically the rules (CPUC 2018a):

- Dictate that batteries can only provide services at the voltage level to which they are interconnected or higher, but not lower (i.e., transmission-level assets can't provide customer-level services);
- Develop categories of services and prioritize "reliability services" over "nonreliability services" and ensure that batteries cannot contract for additional services that would interfere with any obligation to provide "reliability services";
- Require that batteries comply with all performance and availability requirements for services it provides and that noncompliance penalties be communicated in advance;
- Require that batteries inform the utility of any services it currently provides or intends to provide; and
- Take measures to prevent double compensation to batteries for services provided.

These rules help ensure that batteries can select the most cost-effective combinations of services to provide without negatively impacting the reliability of the grid (CPUC 2018a). Although the rules are not specifically oriented towards DPV-plus-storage systems, such rules provide a guideline for resolving issues around maximizing the revenue streams for such systems by providing both customer- and grid-facing services.

New York—In New York, the Public Service Commission directed the NYISO to allow participation of storage systems in both retail markets and wholesale markets, allowing for a broader range of potential income streams for such projects (NYPSC 2018a). Additionally, in 2016, the investor-owned utility Con Edison launched a pilot program to aggregate DPV-plus-storage installations at 300 residential customer sites to provide both lower bills and greater resiliency for customers, as well as aggregated ancillary services to be bid into the NYISO wholesale market on behalf of the utility (ConEdison 2016). The pilot was suspended in 2017 due to permitting issues for storage at residential sites with the Fire Department of New York and the NYC Department of Buildings, but Con Edison intends to resume the project once these issues have been resolved (REV Connect 2018).

FERC—With the adoption of FERC Order 841, FERC directed all wholesale energy market operators under its jurisdiction to develop a participation model for energy storage to ensure these resources can are “eligible to provide all capacity, energy, and ancillary services that the resource is technically capable of providing” (FERC 2018b). This participation model should apply to all storage resources, regardless of whether they are behind-the-meter or on the distribution or transmission system, so long as they are of at least 100-kW capacity. Although the order does not create any tariffs itself, it does ensure that all wholesale markets will offer the opportunity to behind-the-meter DPV-plus-storage systems to participate in wholesale markets, so long as they can meet the minimum technical requirements for provisioning of services. While most DPV-plus-storage systems will be too small to participate, the order opens the door for widescale participation of aggregated distributed storage resources in wholesale markets.

An overview of policy and market context for DPV-plus-storage systems was covered in this section, as regulators make decisions in the broader context of a policy and market environment. This section covered policy and market instruments that may be relevant for DPV-plus-storage systems, including storage, renewable energy, and clean peak mandates, nonbinding storage goals, direct financial incentives and participation in distribution system service markets and wholesale energy markets.

9 Concluding Remarks: Considerations for Regulators

Looking across the spectrum of regulatory issues for DPV-plus-storage systems, there are a number of relevant considerations that regulators can contemplate in order to promote fair, efficient, and well-functioning programs for DPV-plus-storage resources.

Determine the desired role of DPV-plus-storage. Compared to grid-tied DPV systems, DPV-plus-storage has a significantly broader set of capabilities to offer customers and the power system, and regulators are often in a position to guide how these resources are ultimately utilized. Some regulators may wish to see DPV-plus-storage systems deployed to primarily or explicitly serve a customer's own energy demand, and/or for individual customer backup purposes during grid outages. Others may wish to enable DPV-plus-storage systems to provide grid services to the power system, or simply to preserve the option to do so in the future without expensive retrofits. In any case, determining the desired role of DPV-plus-storage systems upfront and ranking them in priority order, before various rules and regulations are advanced, can help to guide a range of decisions related to compensation mechanism design, metering and technical configuration requirements, and technical interconnection processes and requirements.

Customizing rules and requirements based on the characteristics of the DPV-plus-storage system is a key strategy to promote fairness. Creating distinct sets of compensation mechanisms, metering and technical configuration requirements, and interconnection processes—which may be based on system size, the intended use of the system (e.g., an exporting versus non-exporting storage system), and other aspects—can help to ensure that regulatory requirements are appropriate for various segments of the DPV-plus-storage market.

Market context strongly influences compensation mechanism design and its timing. Solar penetration levels, grid management issues, storage deployment mandates or goals, DER technology costs, utility cost recovery and cross-subsidization considerations, and low-income customer concerns are examples of factors that may drive regulators to consider certain design choices at certain times over others. For example, the presence of higher penetrations of solar photovoltaics may create certain grid management issues (e.g., the "duck curve") that could motivate the utilization of more granular, cost-reflective rates (e.g., TOU tariffs) and/or alternatives to NEM to better align customer and grid system needs. On the other hand, jurisdictions which have financially insolvent utilities or significant cross-subsidy schemes in place may be more concerned with ensuring utility revenue sufficiency and avoiding cost-shifting, and may wish to encourage the use of customer-sited storage deployment primarily for self-supply and/or backup during grid outages. Importantly, early-stage DER markets may take different approaches to compensation mechanism design than mature DER markets, depending on these context-specific factors and needs.

Tariff design is the primary tool to align the interests of DPV-plus-storage customers with the broader power system. Relative to grid-tied DPV systems, the presence of a paired behind-the-meter storage system allows customers to better control the magnitude and timing of their electricity consumption from the grid, as well as their grid exports. TOU volumetric energy rates and coincident demand-based charges, if designed and implemented properly, can take advantage of this load shifting capability and incentivize DPV-plus-storage customers to act in a more grid-optimal manner (e.g., reducing consumption and/or increase exports during typical peak demand periods). This behavior, as incentivized by time-variant tariffs, can help ease the management of distributed energy resources on the distribution system and also lead to a reduction in power system operational costs. Implementation of such tariffs may require new metering equipment and administrative responsibilities for utilities but can serve as a grid-friendly incentive for customers to install DPV-plus-storage systems.

Regulators can help balance common utility concerns with consumer interests, ensuring that the implementation cost of solutions is commensurate with the scale of the issue being created. Utilities may voice concerns over issues such as compensation mechanism integrity, energy arbitrage activities, or inadvertent exports from storage systems. There are a variety of known solutions to address these issues, but many of them involve additional expenditures by customers and/or new administrative burdens for utilities. Regulators are in a position to balance utility and customer interests and ensure that utility proposals to mitigate their concerns do not place an undue burden on participating and nonparticipating customers. For instance, while undesirable energy arbitrage could be mitigated through the deployment of additional metering equipment, the cost of installing additional metering equipment might be inappropriately high for smaller scale residential, commercial, or industrial customers.

Regulators can enable business model innovation for DPV-plus-storage systems. Regulators can play a key role in allowing alternative investment and ownership models for DPV-plus-storage systems. Many U.S. DPV assets have been deployed under third-party ownership models (either lease or power purchase agreement) whereby a utility customer does not actually own the asset but receives a portion of the benefit of the DPV generation. Third-party ownership models are already beginning to play a role in storage deployment in the United States, Australia, and elsewhere, both for retrofits and new-build DPV-plus-storage systems. In the future, these resources might be aggregated by third parties, who are allowed to do so, to provide valuable services to distribution companies and/or the bulk power system. Regulators can play a key role in enabling the participation of aggregators and in some cases, defining how they are allowed to operate. This consideration links to broader questions of market reform in the distribution sector.

Standardizing interconnection application forms, processes, and requirements may offer a variety of benefits. Doing so can reduce barriers to market entry for developers, as developers would only have to learn a single process for interconnecting prospective customers with utilities, as opposed to a separate process for all utilities in a particular market. Standardization may also reduce the number of incomplete or incorrectly completed applications that utilities have to process, which both streamlines interconnection processes and reduces utility administrative burdens. On the other hand, creating standardized interconnection standards could be an additional burden for regulators to undertake the effort and periodically update it. Furthermore, additional regulatory approvals may be required if specific utilities want to modify their standards to be more specifically catered to their situation.

Appendix A—Relevant Codes and Standards

Rule 14H—Hawaii Interconnection of Distributed Generating Facilities with the Company's Distribution System

Rule 14H governs the interconnection of both non-inverter-based and inverter-based generating systems located on customer premises operating in parallel to Hawaiian Electric Company's distribution system.[59] The rule explicitly applies to generators that incorporate the use of an energy storage device, such as DPV-plus-storage systems. In addition to grid requirements, which are based on IEEE 1547-2003, the rule also addresses issues related to the management of the interconnection process (e.g., by providing a standard outline for interconnection agreements to be used by the utility), as well as interconnection application evaluation practices (e.g., under what scenarios the utility can initiate a supplemental technical review). Among the technical requirements outlined in the rule are transient overvoltage mitigation and advanced inverter functions that are aligned with capabilities certified by UL 1741 SA and included in IEEE 1547-2018. These functions include the ability to ride through voltage and frequency disturbances, as well as control active power output and reactive power compensation along various pre-determined functions.

Available at:
https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/14.pdf#page=7

Rule 21—California Generator Interconnection

Similar to Rule 14H, Rule 21 "describes the interconnection, operating and metering requirements for generation facilities to be connected to a utility's distribution system."[60] The rule outlines technical requirements from equipment interconnecting to the power system, technical screens to evaluate systems wishing to interconnect, and parameters governing how interconnection applications must be processed by the utilities. As with Rule 14H, Rule 21 provides required capabilities from smart inverters for inverter-based generating systems (including DPV-plus-storage systems), which can be certified using UL 1741 SA. As of the time of this writing, Rule 21 is being updated in accordance with Rulemaking 17-07-007 to incorporate power flow analysis into the technical screens in order to improve interconnection siting decisions and facilitate fast-tracking of qualifying projects (CPUC 2017b).

Available at:
https://www.cpuc.ca.gov/Rule21/

UL 1741—Inverters, Converters, Controllers, and Interconnection System Equipment for Use with Distributed Energy Resources

This equipment testing certification standard covers equipment such as smart inverters used in stand-alone or grid-connected power systems. In addition to verifying normal operating temperatures and acceptable operation during short circuit and overloading conditions, UL 1741 covers the performance of equipment as they provide specific grid functions such as low and high voltage ride through, fixed power factor and anti-islanding. The testing procedures outlined in UL 1741 are designed to certify conformance with the capabilities outlined in IEEE 1547. UL 1741 was updated to UL 1741 SA (Supplement A) to provide additional testing to ensure conformance with California's Rule 21 and Hawaii's Rule 14H for smart inverters.

Available at:
https://standardscatalog.ul.com/standards/en/standard_1741_2

[59] 14H is a subset of Hawaiian Electric Company's Rule No. 14, "Service Connections and Facilities on Customer's Premises."
[60] Each large investor-owned utility in California has its own slightly customized variation of Rule 21, which can be found on the rule's website.

IEEE 1547-2018—Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

IEEE 1547 is a voluntary industry standard for DER connection codes that establishes criteria and requirements for interconnection of DER with electric power systems and associated interfaces (Nagarajan 2018). IEEE 1547 is technology neutral and refers to all DER connecting to the power system, including both grid-tied DPV and DPV-plus-storage systems. Within the family of IEEE 1547.x standards, a new standard (1547.9) will specifically discuss considerations for behind-the-meter storage, expected in 2022. Among other technical requirements, IEEE 1547 establishes a series of performance categories that set minimum requirements for both the ability of a DER to absorb reactive power (specified under Categories A and B) and for the ability of a system to remain online during abnormal system conditions (Categories I, II and III) as well as a range of acceptable communication protocols. To meet IEEE 1547, systems and their individual components must be capable of meeting all performance categories and communication protocols. In reality, some utilities and regulators that utilize IEEE 1547 as a basis for their connection code may select which of the latent capabilities to activate according to local power system characteristics and needs. Others may choose to adopt IEEE 1547 as their connection code wholesale—without any major modifications to the various design parameters.

Available at:
https://standards.ieee.org/standard/1547-2018.html

IEEE 1547.9—Guide to Using IEEE Standard 1547 for Interconnection of Energy Storage Distributed Energy Resources with Electric Power Systems

This forthcoming recommended practice considers the specific application of energy storage systems connected at the distribution system. A separate standard was considered appropriate, given the unique characteristics of storage such as the bidirectional exchange of real and reactive power with the electrical grid. The standard will help provide guidance on technically sound approaches to interconnection and will include topics not covered in IEEE 1547, such as guidance on charging and generation constraints to minimize negative impacts to the distribution grid.

Available at:
https://standards.ieee.org/project/1547_9.html

NFPA 111—Standard on Stored Electrical Energy Emergency and Standby Power Systems

NFPA 111 covers performance requirements for stored electric energy systems providing an alternate source of electrical power in buildings and facilities during interruption of the normal power source. These requirements cover, among others: power sources; transfer equipment; controls; supervisory equipment; accessory equipment needed to supply power to selected circuits; installation, maintenance, operation, and testing requirements pertaining to battery system performance. While regulators for the electric power system may not have jurisdiction over siting and permitting decisions, such as fire safety, it is important for them to take these requirements into consideration as it may impact the feasibility of developing certain DPV-plus-storage systems.

Available at:
https://www.nfpa.org/codes-and-standards/all-codes-and-standards/list-of-codes-and-standards/detail?code=111

NFPA 855—Standard for the Installation of Stationary Energy Storage Systems

Development on NFPA 855 began in 2016 in response to the growth of storage systems in the United States and was first published in September 2019. NFPA 855 covers requirements for the installation of stationary energy storage systems, such as in DPV-plus-storage systems. This includes acceptable locations for installations, sizing and separation of system components, and fire suppression and control. The standard covers electrochemical, capacitor, fuel cell, flywheel, and superconducting magnet systems. NFPA 855 also considers the ventilation, detection, signage, listings, and emergency operations associated with energy storage systems to help mitigate fire and life safety hazards. For utility-operated storage facilities, utilities in the United States are typically allowed to use the NFPA 70 and ignore NFPA 855 at their discretion.

Available at:
https://www.nfpa.org/codes-and-standards/all-codes-and-standards/list-of-codes-and-standards/detail?code=855

NFPA 70—NEC

The NEC is the de facto electrical code in the United States for the installation of electrical equipment and wiring, applying to residential, commercial, and industrial facilities. It is updated every three years, with the next version expected in late 2019. The rules cover installations, circuits and protection, methods and materials for proper wiring, and general-purpose equipment. The rules also cover special equipment, emergency systems and communication systems. The NEC also often refers to listed devices and equipment that has been properly designed, manufactured, tested or inspected by an appropriate listing agency, or national recognized testing laboratories, such as UL. Some iteration of the code has been wholesale adopted at the state-level in all but three U.S. states, with widespread county/municipality adoption of the code in those three states. The NEC has also been adopted by many U.S. territories and over a dozen countries. [61] Because of the frequent changes in each update cycle, many states, cities, and counties often adopt a version of the NEC but may not adopt the latest version upon publication. Importantly, AHJs may adopt requirements beyond those in the NEC.

Available at:
https://www.nfpa.org/codes-and-standards/all-codes-and-standards/list-of-codes-and-standards/detail?code=70

[61] For more information on the adoption of the NEC in the United States and globally, see: https://www.nfpa.org/NEC/NEC-adoption-and-use.

Appendix B—DPV-Plus-Storage Technical Configurations

This section provides describes several key design configurations for DPV-plus-storage systems that are popular in the United States and may become prevalent in other international contexts, and also provides illustrative diagrams[62] of these configurations. These design configurations have been included primarily because they allow for backup power when energy is not available from the grid, an important consideration in both the United States and around the world.[63]

For DPV-plus-storage systems, one important consideration is whether to couple the hybridized system with an AC or DC connection. In AC-coupled systems, the battery and the PV array have separate inverters, while in DC-coupled systems they share a single inverter. Typically for behind-the-meter systems, DC-coupled systems share a multiport hybrid inverter that allows bidirectional power flow to and from the battery, while only allowing unidirectional power flow from the PV array. While not necessary for DC-coupled systems, this multiport hybrid inverter allows the battery to charge from both the grid and the PV array, increasing the overall flexibility of how the coupled system can operate (Ardani et al. 2017). Although a full treatment of battery and PV inverters is outside the scope of this work, the coupling strategy and associated equipment requirements of these systems may have important implications.

For behind-the-meter applications in the United States, most DPV-plus-storage systems to date have been AC-coupled, in particular for retrofits and for larger commercial and industrial customers (Moskowitz 2017). When retrofitting existing PV systems under AC coupling, the battery system can be added in parallel without replacing the PV inverter. Retrofits under DC-coupling, however, require the PV inverter to be replaced, which can add significantly to project costs (Ardani et al. 2017). Commercial and industrial DPV-plus-storage systems are typically AC-coupled due to limited inverter sizing and system space constraints. Currently, the multiport hybrid inverters used in DC systems come in select sizes, and are usually better suited for smaller residential customers. Furthermore, DC-coupled systems require the batteries to be interspersed throughout the photovoltaic array, which can be an issue for larger systems if the customers have limited space (Moskowitz 2017). Despite these limitations, for smaller customers installing new DPV-plus-storage systems not limited by space or inverter sizing, DC-coupling offers several key advantages. Even though multiport hybrid inverters are more expensive than standard inverters, DC-coupling tends to have lower overall costs due to shared inverter components and reduced wiring costs. This cost reduction is particularly relevant for smaller systems, for which inverter equipment is a significant driver of total system costs. For systems in which the DPV generation is often stored and consumed at a later time, rather than instantaneously consumed at the time of generation, DC-coupled systems also have higher efficiencies than AC-coupled systems as they suffer fewer inefficient AC-to-DC and DC-to-AC conversions (Ardani et al. 2017). Furthermore, DC-coupled systems avoid PV clipping, in which some DPV generation is dumped due to power limitations of inverters, which tend to be undersized relative to the maximum PV array output (Moskowitz 2017).[64] The combination of high efficiency and avoided clipping means DC-coupled systems may be better suited to maximize DPV generation to meet on-site demand and/or sell electricity back to the grid, improving system economics. Figure B- 1 and Figure B- 2 provide illustrative diagrams for AC-coupled and DC-coupled systems, respectively. Table B- 1 summarizes the differences between AC- and DC-coupled systems.

[62] Importantly, these illustrative diagrams are not equivalent to electrical line diagrams, but instead are intended to qualitatively describe the various storage-related design configurations.

[63] Stand-alone storage systems are not covered in this appendix. While storage-plus-DPV systems have been more common in the United States relative to stand-alone storage systems, stand-alone storage systems may be more prevalent in other country contexts depending on the frequency of load shedding events and the premium that customers place on reliable electricity services.

[64] For information on PV clipping, see this article from Sandia National Laboratories' PV Performance Modeling Collaborative.

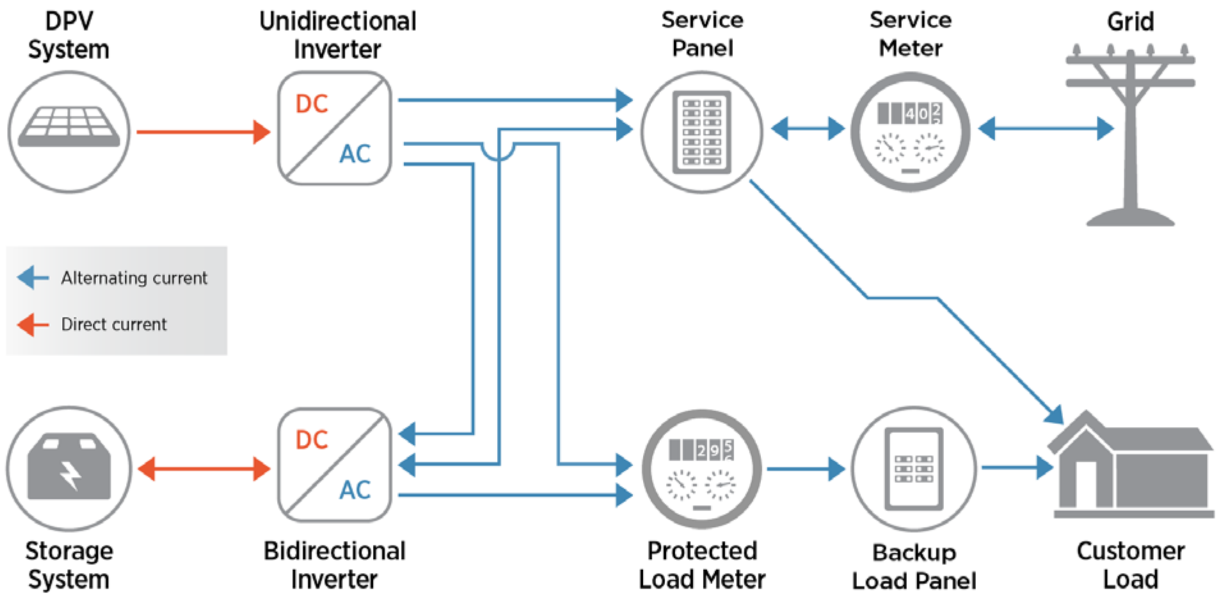

Figure B- 1. AC-coupled DPV-plus-storage system with backup enabled

Source: Original [*Illustration by Christopher Schwing, NREL]*

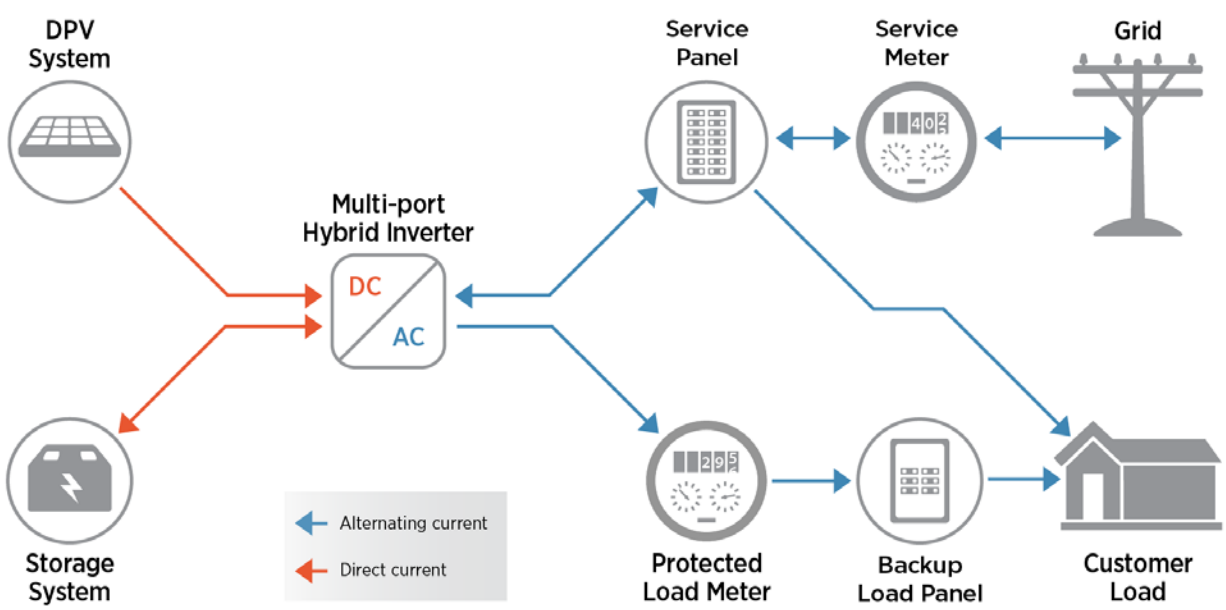

Figure B- 2. DC-coupled DPV-plus-storage system with multiport hybrid inverter with backup enabled

Source: Original [*Illustration by Christopher Schwing, NREL]*

Regardless of how the DPV-plus-storage system is coupled, to continue supplying power during a grid outage, DPV-plus-storage systems require inverters capable of switching from the normal service entrance, which connects the customer to the DPV-plus-storage system and to the grid, to a special backup load panel. These backup load panels provide an entrance to the customer but not to the larger grid, allowing DPV-plus-storage to supply power to customers without endangering utility line workers. Configurations may also include a protected load meter, which only allows power to flow from the inverter to the backup power panel. Importantly, backup panels and protected load meters incur additional costs both for the equipment and installation. Furthermore, from an administrative standpoint, installers may need to work with customers to determine which customer loads should be served through the backup load panel in the event of a grid outage.

Table B- 1. Comparison of AC- and DC-Coupled Systems

	DC-Coupled Systems	AC-Coupled Systems
Inverter Requirements	A single shared inverter, typically a multiport hybrid inverter.	Two separate inverters, one each for the battery and PV array.
Size Availability	Multiport hybrid inverters come in a limited number of sizes, normally at the residential scale, although this may change as the industry matures.	A wide range of inverter sizes suitable for all applications are available.
Space Requirements	DC-coupled systems tend to require more space and must be co-located, as the batteries are interspersed throughout the array	AC-coupled systems can have the battery and PV array located completely independently of one another.
System Costs	Tend to be less expensive for new projects due to shared inverter components. This cost reduction is particularly pronounced for small systems, for which the inverter comprises a larger share of total system costs.	Tend to be more expensive for new projects as inverters and associated equipment, wiring and installation costs are duplicated.
System Efficiency	Tend to be more efficient in applications in which the DPV generation is stored and consumed at a later date. Systems do not typically suffer from PV clipping, increasing overall available PV generation.	Tend to be more efficient in applications in which the PV generation is consumed immediately. PV generation is often clipped, due to power constraints of the inverter, leading to lost energy.
Suitability for Retrofit Versus New Build	Better suited for new systems, as retrofitting existing PV arrays with a battery requires replacement of photovoltaic inverter.	More common in retrofits as the battery can be added to the system in parallel without affecting the existing DPV system.
Appropriateness for Customers	Better suited for residential or smaller commercial customers not subject to inverter sizing limitations or space constraints.	Better suited for larger commercial and industrial customers or customers with siting constraints.

Adapted from Ardani et al. 2017

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