Capturing More Value from Combinations of PV and Other Distributed Energy Resources

John Shenot, Carl Linvill, Max Dupuy, and Donna Brutkoski

Regulatory Assistance Project (RAP)

NREL Technical Monitor: Sara Farrar

NREL is a national laboratory of the U.S. Department of Energy
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National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
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By John Shenot, Carl Linvill, Max Dupuy, and Donna Brutkoski

AUGUST 2019

Regulatory Assistance Project (RAP)®

50 State Street, Suite 3
Montpelier, Vermont 05602
USA

Telephone: +1 802-223-8199
Email: info@raponline.org
raponline.org
linkedin.com/company/the-regulatory-assistance-project
twitter.com/regassistproj

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Figures

Tables

Abbreviations

AMI .... advanced metering infrastructure

APS .... Arizona Public Service Co.

BPA........ Bonneville Power Administration

BQDM...... Brooklyn-Queens Demand Management

CAISO ..... California Independent System Operator

CaSPM..... California's Standard Practice Manual for Economic Analysis of Demand-Side Programs and Projects

C-E .... cost-effectiveness

CHP .... combined heat and power

DER........ distributed energy resource

DERP ...... DER provider

DG .... distributed generation

DPV........ distributed solar PV

DR .... demand response

DRIPE...... demand reduction induced price effect

DSIRE...... Database of State Incentives for Renewables & Efficiency

DSP........ distribution system planning

EM&V ..... evaluation, measurement, and verification

EPRI .... Electric Power Research Institute

EV .... electric vehicle

FERC ...... Federal Energy Regulatory Commission

FIT......... feed-in tariff

IDP .... integrated distribution planning

IEEE .... Institute of Electrical and Electronics Engineers

IRP .... integrated resource planning

IRR .... internal rate of return

ISO .... independent system operator

kWh .... kilowatt-hour

LBNL ...... Lawrence Berkeley National Laboratory

LSE .... load-serving entity

MWh ...... megawatt-hour

NEM .... net energy metering

NGR .... non-generator resource

NIST .... National Institute of Standards and Technology

NPV .... net present value

NREL ...... National Renewable Energy Laboratory

NSPM...... National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources

NWA .... non-wires alternative

NY PSC .... New York Public Service Commission

OCEI ...... Oakland Clean Energy Initiative

PAC........ program administrator cost test

PDR .... proxy demand resource

PPA........ power purchase agreement

PRD .... price-responsive demand

PT .... participant test

PTR .... peak-time rebate

PUC .... Public utility commission

PURPA ..... Public Utility Regulatory Policy Act

PV .... photovoltaic

RAP .... Regulatory Assistance Project

RDRR ...... reliability demand response resource

REC .... renewable energy credit

RIM........ ratepayer impact measure

RMI........ Rocky Mountain Institute

RPS........ renewable portfolio standard

RTO .... regional transmission organization

SCT........ societal cost test

RVT........ resource value test

TOU .... time-of-use

TRC........ total resource cost test

UL .... Underwriters Laboratories

U.S. DOE ... U.S. Department of Energy

V2G .... vehicle-to-grid

VOS .... value of solar

Executive Summary

Much has been written about the value of solar photovoltaic (PV) generation, but less about the value of some of the other distributed energy resources (DER) — other forms of distributed generation (DG), energy storage, electric vehicles (EVs), demand response (DR), and energy efficiency (EE) — or how these resources can be combined. This paper considers the types of values (or "value streams") that combinations of DERs can create, examines three "use cases," and explores a path for capturing more of the full value of these combinations.

Cost of Service, Value of Service, and Value Streams

To begin our analysis, we must clarify what we mean by "value." The traditional cost-of-service model as used by monopoly utilities still governs some electric utility services, but a more diverse, competitive marketplace has emerged for other services — with independent power producers, energy service companies, and in some regions competitive retail electricity suppliers all in the mix. In this new marketplace, value-of-service procurement has emerged as a complement to cost-of-service ratemaking.

Valuation and cost-benefit analyses have been staples of policy and regulatory decisions regarding ratepayer-funded energy efficiency programs for more than 30 years, and the evaluation, measurement and verification (EM&V) approaches applied to these programs are instructive in considering the value of combinations of DERs. Two key principles of EM&V approaches are to consider a broad range of value streams and to consider the parties to whom each value stream accrues. (Ultimately, any question about the value of an electricity service must consider "value to whom?") The seminal document for cost-effectiveness (C-E) testing, California's Standard Practice Manual, defines five ways to test C-E using various methodologies to assess a program's effect on costs and benefits for utilities, customers, program administrators, and related policy goals. The recently produced National Standard Practice Manual proposes a sixth test, one that considers societal costs more widely. Although these tests were developed to evaluate energy efficiency programs, they are often also used to evaluate DER programs and resources.

DERs are capable of providing a wide range of value streams, which include:

- Reducing energy costs for participants and utilities;
- Helping utilities avoid generation capacity costs, such as through peak-shaving DR;
- Reducing the need for utility investment in transmission and distribution capacity; and
- Lowering prices via the demand reduction induced price effect (DRIPE).

Quantifying the economic value of each value stream from each perspective can be difficult, inexact, and controversial. At the most basic level, quantitative values can be estimated using market prices as proxies, or the values can be administratively determined by utilities or regulators. In addition, the economics of many value streams can be time-dependent, location-dependent, or interdependent.

Potential Value of Combinations of DERs

A PV system installed in isolation is limited in the services and value streams it can provide. But when PV is combined with other DERs, the resources' total value can be greater than the sum of the values of each component in isolation. Examples of the benefits of these combinations include:

- **PV + Storage:** When storage is added to a PV system, the primary limitation of PV — that it only provides power when the sun shines — is alleviated. This allows customers to plan storage and use around high-value times and reduce demand charges. With further investment in microgrid technology, this combination can also enable resilience by powering critical loads during outages.

- **PV + EV:** When an EV replaces a fossil-fueled vehicle, the environmental impacts depend on the fuel mix and emissions of the power system from which the vehicle is drawing energy (a measure that is likely to change over time). An EV that is charged with power generated by PV — a zero-emissions fuel — will have maximum environmental benefits. For utilities, combining an EV with PV may also reduce the need for capacity upgrades to the transmission and distribution systems.
- **PV + DR:** The same technologies and techniques used for DR in isolation can be combined with PV to create even more value. For example, flexible loads such as electric water heating, air conditioning, electric space heating, and pool pumps can be programmed to take advantage of times when the generation from a customer's PV system exceeds their momentary demand for other end uses. From a utility or independent system operator (ISO) perspective, this combination can be especially valuable in terms of flexibility.

Current Mechanisms for Capturing the Value of DERs

DERs generally get installed and operated only when they are cost-effective from the participant's perspective, so accurate compensation is key. Broadly stated, there are at least four common mechanisms for compensating customers.

Tariffs or Bill Credits

Customers who have DERs can be directly or indirectly compensated by their utility by way of their utility bill. Beyond traditional tariffs, many utilities also offer tariffs that reflect the time-varying nature of system costs — and therefore more accurately compensate DER customers. These include real-time pricing, critical peak pricing, variable peak pricing, other time-of-use (TOU) rates, and peak time rebates (PTR). Almost all utilities offer special tariffs to customers who have PV or other forms of DG, most commonly net energy metering (NEM) and net energy billing tariffs. A small number of utilities offer either feed-in tariffs (FITs), which are more common in Europe, or value of solar (VOS) tariffs. Community solar programs, which provide bill credits to participating customers, have grown rapidly and now exist in more than 40 states.

For each DG tariff or community solar program, the utility or its relevant regulatory authority decides how much credit customers should get for each kilowatt-hour (kWh) generated by the DG system. In many cases, these decisions are informed by investigations into utility system value. A VOS tariff is explicitly designed to offer compensation that reflects this value, whereas NEM and net energy billing tariffs are simpler.

Industrial or large commercial customers who have combined heat and power (CHP) systems or microgrids that consist of combinations of DERs are typically offered a "standby" or "partial requirements" tariff. In this case, the customer pays different rates to the utility for supplemental, maintenance, and emergency backup power.

A few utilities now offer other tariffs to customers who have specific combinations of DERs, such as Hawaii Electric Company's time-sensitive Smart Export tariff for customers who have PV and storage or "whole-house" rates that include EV charging and encourage flexible scheduling of that use. The challenge for regulators and utilities in designing any of these tariffs is to strike a balance between simplicity and accurate capture of value.

Market Revenues

It is also worth considering how DER combinations can provide services to the regional ISO wholesale markets, help to support renewable integration at that wider level, and enjoy revenue corresponding to the bulk power system value of those services. For example, PV, storage, and electric water heaters can all provide fast frequency response and help shape and shift load. ISOs all allow DERs to participate in principle, but they vary in terms of eligibility and compensation. These rules can limit DER participation — for example, each ISO has minimum size requirements, although DERs can be aggregated to meet these requirements collectively.

The Federal Energy Regulatory Commission (FERC) established rules in Order 719 (2008) requiring each ISO to amend its tariffs as needed to allow for participation of DR aggregators in organized wholesale electricity markets. Because of Order 719, DR resources have been more active in wholesale markets than other DERs. Distributed solar PV may face some particular hurdles to ISO participation; with net metering, the value to customers in self-supplying energy will usually exceed the value of that energy in the wholesale markets. Evolving interconnection standards should help unlock additional capabilities of DG, however.

Distributed solar PV may face some particular hurdles to ISO participation. Evolving interconnection standards should help unlock additional capabilities of DG, however.

Several state public utility commissions (PUCs), including New York and California, have begun to discuss whether to create markets for electricity services at the distribution system level, to provide such services as voltage support. Participation models could also be expanded beyond aggregations of a single type of DER to combinations of different types, such as PV and storage, that can work together to offer a guarantee of availability during system peaks. This could allow PV to receive a higher capacity credit if market rules allow.

Finally, PV and other qualifying DG resources can participate in renewable energy credit (REC) trading markets. REC values associated with some DG resources can be significantly higher in states where the renewable portfolio standard includes a "carve-out" for those resources. However, customer perceptions of high transaction costs and loss of control over the REC may limit the ability to capture this value from markets.

Power Purchase Agreements or Contracts

Utilities often enter into power purchase agreements (PPAs) or other contracts with independent power producers or third-party energy service companies to provide energy, capacity, or ancillary services. Utilities most commonly offer compensation through bundled, fixed-price per-kWh rates, although owners of PV and other renewable DG can also sell "undifferentiated" power to a utility by way of a PPA and sell their RECs to another party through a separate contract.

One-Time Payments or Credits

Federal, state, and local authorities offer or require utilities to offer one-time incentives to DER owners — tax credits, customer rebates, and the like. As with tariffs, new options are emerging for combinations of DERs; examples include the federal tax credit being extended to storage when it is combined with PV, or a Minnesota cooperative that offers customer discounts to pair community solar with grid-controlled water heaters.

Examples of Use Cases for Combining PV With Other DERs

Experience to date suggests that some DER use cases are proving more attractive (or practical) than others, and some value streams are being captured much more frequently and much more completely than others.

Use Case 1: Installing DERs to Earn Wholesale Electricity Market Revenues

DER participation in wholesale markets has been dominated so far by DR resources, although this is changing, given FERC's 2018 ruling that each ISO must develop participation models designed specifically for storage. In this context, participation models for DERs in the California Independent System Operator (CAISO) markets are worth examining. CAISO has been a leader in tailoring market participation models for storage, including aggregated storage. Participation to date has been modest, but there are several ways in which DERs can participate in the CAISO market.

- **Proxy Demand Resource (PDR) and Reliability Demand Response Resource (RDRR).** These models are for resources that can be dispatched to reduce demand, such as traditional DR load curtailment and storage resources. PDR and RDRR do not allow injection of energy into the grid (which excludes PV participation).

- **Non-Generator Resource (NGR).** This model is designed for storage or storage-like resources, but allows for aggregations of DERs including PV. NGRs can reduce demand or inject energy into the grid, providing a wide range of services to CAISO, including energy, reserves, and regulation services in all markets. A Pacific Gas & Electric demonstration program found that the most valuable NGR resource was frequency regulation.

CAISO is the first ISO to fully open the door to combining PV and other DERs. Although most ISOs currently are characterized by low prices, high reserve margins, and modest need for ancillary services, the evolving needs of the grid may increase the value of DER combinations.

Use Case 2: Installing DERs for Resilience

In recent years, we have seen the development of combinations of DG, electricity storage, and microgrids as supplements or alternatives to what was once the only realistic technology for riding through grid outages: diesel backup generation. Extreme weather and cybersecurity concerns have made resilience a major concern. State and local governments are using DER combinations to respond to this, from net-zero-energy, PV-equipped city buildings in Salt Lake City to solar and storage facilities in Minnesota and Massachusetts. Branches of the U.S. military are also developing onsite renewable generation combined with energy storage or microgrid capabilities. Such efforts have revealed several important opportunities and limitations.

- A grid-connected PV system will go down when the grid goes down unless it is islandable, and adding microgrid capability and possibly storage to a PV installation adds substantially to costs;

- EE is a crucial but often overlooked component of energy resilience, allowing microgrids to provide services for as long as possible during an outage; and

- An owner of a DER microgrid may need to forgo some value that could accrue during regular operations to ensure sufficient stored energy for an emergency.

Use Case 3: Installing DERs as a Non-Wires Alternative to Utility Infrastructure

The experience of the Bonneville Power Administration in the San Juan Islands in the 1990s is perhaps the first successful use of non-wires alternatives (NWAs) to defer an expensive transmission project. Since then, NWA proposals have evolved to use energy efficiency, DR, DG, and storage to avoid building unnecessary infrastructure. Examples include the Brooklyn-Queens Demand Management program, which allowed Con Edison to put off a $1.2 billion substation upgrade, and the Oakland Clean Energy Initiative, which will enable the retirement of an uneconomic power plant without a transmission upgrade.

These examples were driven by "traditional" reliability concerns, but the non-wires opportunities for DERs in the future are increasingly caused by DER growth itself. Distributed solar and EV charging are two likely drivers — with the distinction that they will likely affect distribution system (as opposed to transmission) investment. One possible venue for considering this is an integrated distribution planning (IDP) proceeding.

More recent examples of NWAs include the Borrego Springs microgrid in California, National Grid's Tiverton Substation project, and Central Maine Power's Boothbay project. In each case, DER combinations offer the local energy, capacity, and voltage support required for critical needs at the time and in the place required.

Use Case 4: Using DERs to Address Environmental Challenges

Coordinated and targeted DER deployments have the potential to improve air quality, reduce health costs, and satisfy federal Clean Air Act requirements at a lower cost than traditional pollution control measures. This has yet to be fully explored, but the potential environmental benefits of DER combinations are indisputable. Energy efficiency and PV clearly reduce the need for utility-scale generation of electricity, reducing emissions, while any increase in electricity demand from EVs tends to be more than offset by decreases in tailpipe emissions. DR or storage can have positive or negative effects on emissions depending on when they are used, but combining them with energy efficiency or PV can ensure that the air quality impacts are positive.

A Path Toward Capturing More Value From DER Combinations

Capturing the full value of DER combinations is an ambitious, perhaps only aspirational, goal. Fortunately, progress can be made incrementally through the independent actions of diverse decision-makers. In some cases, this can do enough to turn a DER project from a negative value proposition to a positive one. Experimentation and testing will be necessary to find optimum solutions, and solutions will have to adapt to changing market and technology realities over time.

The specific actions that can be taken fall into five broad categories, explored here.

Technology, Metering, Communications, and Data Systems

Before we consider the actions that can lead to compensation commensurate with the value of DER combinations, we must first examine some crucial technologic improvements that can increase the ability of DERs to provide value and information sharing about that value.

The emergence of smart inverters allows resources such as PV, distributed wind, and storage to provide ancillary services and to maximize energy value by "riding through" some grid disturbances. However, those results will not happen automatically without the use of updated technologic standards.

First, the 2018 update to the IEEE 1547 interconnection standard is significantly better for DERs. It requires ride-through capability, clarifies storage interconnection, and offers the opportunity to consider expedited interconnection processes. State PUCs interested in capturing the benefits of the new standard will want to become engaged as utilities implement it.

Second, state PUCs and utilities will also need to require implementation of some of the optional features included in the Underwriters Laboratories (UL) 1741 5A standard for inverters. UL 1741-compliant inverters may be capable of providing grid services, but that capability won't necessarily be activated unless PUCs and utilities require it.

Beyond that, there are many prerequisite steps relating to metering, communications, and data systems that are necessary for enabling some of the value streams to be revealed and compensated.

- Deployment of advanced metering infrastructure (AMI);
- Grid modernization proceedings by state PUCs aimed at implementing other smart grid technologies;
- Upgrades to allow system operators to better track two-way DER transactions;
- Policies and procedures to protect privacy while allowing data sharing;
- Cybersecurity standards put in place by FERC and the states;
- Continued development by FERC and the National Institute of Standards and Technology (NIST) of a smart grid interoperability framework;
- Accurate registration of DER capabilities; and
- Optimization algorithms and system controls for managing DER combinations and aggregated DERs.

Smart Retail Rate Design (Tariffs)

Because system costs and potential avoided costs are time- and location-dependent, appropriate compensation of DERs — and of combinations such as solar plus batteries or solar plus smart water heaters —is best managed through retail electricity rates that vary by time and location.

In our work on residential and commercial rates, RAP has recommended that retail rate designs adopted by utilities, other load-serving entities (LSEs), and state PUCs include the following key attributes:

- **Customer charges.** For the most part, they should be designed only to recover costs that vary by number of customers, such as metering, billing, and collection costs.

- **Demand charges.** For nearly all residential customers, these should only recover the costs of the final line transformer and service drop because those are the only system components sized to meet the individual customer's peak demand. For a non-residential customer, an additional site infrastructure charge may be appropriate if dedicated distribution system facilities are required to serve peak demand.

- **Energy charges.** All other utility costs are best recovered through energy charges that align customer costs with long-term system cost drivers. For residential customers, that means a simple TOU rate with off-peak, mid-peak, on-peak, and critical peak time periods. PTRs offer an alternative to critical peak prices, as do super-off-peak rates for EV charging and other flexible loads. For non-residential customers, more complex rates can be used, potentially including real-time pricing. And a nodal or locational element may send non-residential customers a better price signal.

- **Bi-directional charges.** Customers who are capable of injecting excess energy into the grid from a DER should be compensated at the same time-varying energy rates that they would pay for consumption. Bidirectional charges can be particularly effective for combinations of DERs, because it ensures that customers are billed or credited an appropriate amount based on their net energy consumption.

With these rate designs, RAP believes that customer charges and demand charges that are only applied to DER customers will be unnecessary. Special tariffs that apply only to DER customers may remain appropriate if they more accurately represent the full net value of services. Retail rate design can also address one of the key challenges of the utility business model: the "throughput incentive" that can lead utilities to oppose or thwart policies that reveal the value of DERs and compensate customers for installing them. Revenue decoupling is an elegant and commonplace solution to this problem.

Retail rate design can address a key challenge: the "throughput incentive" that can lead utilities to oppose or thwart policies that reveal the value of DERs and compensate customers for installing them.

Markets

Capturing greater value from DER combinations requires that the electric system become more transactive. Steps that can be taken here include:

- Expanding the range of energy prices allowed in wholesale markets by adopting price caps that more closely reflect the average value of lost load;

- Instituting a "price-responsive demand" (PRD) program for resources that commit to curtailing load any time the wholesale energy price rises above a certain level chosen by the customer;

- Reforming forward capacity markets in places that currently have them, such as ISO New England and PJM. Segmenting capacity markets to procure the right services at the right times will lead to better outcomes than, for example, offering a single annual capacity product;

- Revising market rules as necessary to expand participation opportunities for DERs and DER combinations in existing ISO market segments and compensation mechanisms. This revision should ensure that DERs and combinations are eligible to compete to provide any wholesale services they are capable of providing, and the minimum size requirement for participants should be no greater than needed to keep market operations reasonably manageable;

- Expanding opportunities for aggregators of DERs and DER combinations to compete in existing wholesale market segments, including energy, capacity, and ancillary service markets;

- Clarifying long-term forecasted needs for more specific ancillary services or capabilities, and not just capacity, through improved planning processes (see below);
- Establishing or expanding NWA processes to identify least-cost solutions to emerging system reliability issues and ensure DERs and aggregated DER combinations are eligible to bid into competitive procurement processes that address those issues;
- Identifying emerging energy system priorities at the community or local government level (resiliency, environmental goals, or transportation electrification) that can potentially be served by DERs;
- Investigating establishing distribution-level competitive transactive markets for resources to meet distribution system needs; and
- Facilitating load registration mechanisms like the Open Energy Efficiency Platform, the Open Hosting Capacity Platform, and blockchain to resolve local reliability issues with decentralized solutions.

Planning

Power sector planning can happen at three different levels, each of which creates an opportunity to identify and capture the value of DERs and DER combinations: transmission planning, integrated resource planning (IRP), and distribution system planning (DSP). These processes are explored here.

Transmission planners need to develop improved tools and practices for forecasting system needs and identifying least-cost solutions. Four areas for potential improvement should be considered.

- Better forecasts of generation from non-dispatchable, near-zero-operating-cost, variable energy resources like PV and wind;
- Accounting for the potential to activate flexible loads and energy storage devices to reduce peak loads and maintain power quality on the bulk power system;
- Clarification of long-term forecasted needs for more specific ancillary services or capabilities, and not just capacity (see previous section); and
- A proactive approach to soliciting NWAs so that opportunities are available.

Utilities that develop IRPs can also improve their practices to better account for the potential of DERs to meet needs more reliably, at lower cost, or with less risk. Areas for potential improvement include:

- Utility development of more accurate long-term load forecasts, accounting for utility-scale variable energy resources and DERs;
- Improvements to the production cost models used to develop IRPs so that they can more accurately model supply demand in sub-hourly increments;
- Removal of artificial constraints on the contributions of DERs;
- Assessments of risks and uncertainties, which tend to reveal a higher value for resources that are flexible and can be procured in small increments;
- Consideration of non-energy impacts from a societal cost test or resource value test perspective; and
- Quantification of the value of system resilience.

Although DSP is a relatively new development in utility regulation, numerous reports offer guidance, examples, and case studies. To identify and capture DER value at the distribution level, utilities should:

- Develop and use improved techniques for long-term load and DER deployment forecasts;
- Proactively solicit NWAs to determine if the identified distribution system needs can be met at a lower cost than through a utility infrastructure investment; and
- Assess the “hosting capacity” of their existing system and make hosting capacity maps publicly available for customer and third-party developer use.

Finally, opportunities exist to better integrate and coordinate all these planning processes across the transmission, generation, and distribution domains, ensuring that value is accurately considered.

Utility Procurement

Utilities procure resources or the output from resources for varying reasons and through varying mechanisms. Some of the procurement-related actions that will lead to capturing value from DERs have already been noted, but they will be briefly repeated here along with some actions not yet discussed.

- State regulators have authority to establish the just and reasonable rates that regulated utilities offer as compensation to the Public Utility Regulatory Policy Act of 1978 (PURPA)-qualifying facilities. PURPA stipulates that these rates must not exceed the utility's avoided costs, but states have latitude to interpret that. At a minimum, regulators could include avoided line losses, any demonstrable avoided capacity costs, and avoided costs of compliance with state renewable energy mandates (where applicable) without violating PURPA.
- When specific resources like energy efficiency and DR are procured through utility programs, it is best to evaluate cost-effectiveness using the same test, ideally the societal cost test or a version of the total resource cost test or resource value test that considers non-energy costs and benefits.
- Introducing competition to utility procurement is an essential step in revealing DER value, and all-source procurement requires the utility to specify the capabilities they need, rather than the resource type(s) they seek to procure. Furthermore, where utilities are not fully restructured, regulators can require utilities to evaluate third-party–owned solutions, including DER combinations and aggregations of DERs, as an alternative to a utility-owned resource.
- In the United States, investor-owned utilities earn returns for their shareholders almost entirely through capital investments in generation, transmission, and distribution system infrastructure. This causes a capital expenditure ("capex") bias that is a built-in disincentive to facilitate DERs. The long-term solution is probably to reconsider the utility business model such that shareholder returns depend less on capex and more on total expenditures ("totex") or performance against goals relating to the public interest and customer preferences.

Conclusion

The rapid growth in distributed PV and storage systems, and the projected growth in EVs, offers clear evidence that participants are realizing value from DERs — but this alone doesn't imply that they are capturing as much value as they could or should. The past five years have seen technology developers racing to meet growing consumer demand for DERs, states filling their traditional role as "the laboratories of democracy," and ISOs testing different market products and market rules. Although much work remains, some innovations have already proven to be successful in terms of overcoming barriers to deployment and the capture of value.

To unlock value, the highest priority actions will vary by stakeholder and by location, and there is no reason to wait for someone to develop a comprehensive action plan. Suggested priorities include our technology, metering, communications, and data system recommendations, as well as updating rate design and prioritizing NWAs.

I. Introduction and Purpose

Much has been written about the value of solar PV generation, and some jurisdictions in the United States have gone so far as to adopt retail electricity tariffs that credit or remunerate owners of PV based on that value. However, less has been written about the value of some of the other distributed energy resources (DERs) — by which we mean to include other forms of distributed generation (DG), energy storage, electric vehicles (EVs), demand response (DR), and energy efficiency. And very little has been written exploring how the value of combinations of PV and other DERs differ from the individual values of each DER. This paper aims to promote more conversation on that latter point.

In Section II of this paper, we lay a foundation for later discussions by explaining the concepts of value, value streams, and cost-effectiveness. In Section III, we explore the types of value streams that combinations of DERs can create for electricity customers, the local electric utilities that serve them, the broader electric grid serving a wider geographic area, and society in general. In Section IV, we summarize the potential mechanisms for compensating the owners of DERs for the values they deliver. In Section V, we examine four "use cases" — reasons that motivate customers to consider combinations of DERs — and for each use case we consider which value streams are being captured today in practice and which are not. Finally, and most important, in Section VI we explore a path forward for capturing as much of the full value of combinations of DERs as is practicable.

II. Cost of Service, Value of Service, and Value Streams

Before we can explore ways to capture more value from DER combinations, we must begin by clarifying what we mean by "value."

Cost-of-service ratemaking took root in an era when utilities were the sole providers of virtually all electricity services within their defined service territory. Today, however, a more diverse marketplace has emerged.

For more than a century, electric utilities have used cost-of-service principles to establish retail electricity rates. In cost-of-service rate-making, utilities determine their costs of serving customers' electricity needs and then design retail rates to recover those costs. Cost-of-service ratemaking took root in an era when utilities were the sole providers of virtually all electricity services within their defined service territory. Utilities were the sellers of services, and their customers were the buyers. Utility commissions were established to regulate retail rates and ensure that utilities did not abuse their monopoly power by charging rates in excess of what might be expected in a reasonably efficient competitive market.

Today, some services (e.g., delivery of power at distribution voltages and metering) are still provided by monopoly utilities to consumers at retail rates based on cost-of-service principles, but a more diverse marketplace has emerged for other services. There are independent power producers, energy service companies, and in some regions competitive retail electricity suppliers in the mix. Some of these companies can sell electricity services directly to retail customers. Furthermore, many consumers now own DERs and sometimes they provide services to utilities or to the wholesale electricity markets managed by ISOs.[1] Prices paid for these electricity services are not necessarily based on the providers' cost-of-service. Instead, value-of-service procurement has emerged as a complement to cost-of-service ratemaking. Utilities now procure electricity services from other providers based on a consideration of whether the value of the service exceeds the cost the utility must pay to procure the service.

Valuation and cost-benefit analyses have been staples of policy and regulatory decisions regarding ratepayer-funded energy efficiency programs for more than 30 years. Evaluators have routinely assessed the economic value of certain attributes of energy efficiency measures and compared the aggregated benefits of those measures (i.e., the value streams) to their costs to determine which measures are cost-effective. The evaluation, monitoring, and verification (EM&V) approaches applied to energy efficiency measures, and the lessons learned over four decades, are instructive as we seek to identify and capture maximum value from combinations of DERs.

Two key principles of EM&V approaches are to consider a broad range of value streams and to consider the parties to whom each value stream accrues. (Ultimately any question about the value of an electricity service must consider "value to whom?") The importance of both elements has been understood since the beginning of ratepayer-funded energy efficiency programs in the 1970s. The seminal reference document for C-E testing in the electric power sector is California's *Standard Practice Manual for Economic Analysis of Demand-Side Programs and Projects (CaSPM).*[2] The CaSPM defines five ways to test C-E and offers a standard methodology for conducting each test. Each test considers the C-E question from a different perspective and identifies categories of costs and benefits that should be included in the test. In 2017, a group of energy efficiency professionals from multiple organizations collaborated to produce a *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources* (NSPM) that builds on the CaSPM[3]. The NSPM proposes a sixth C-E test, the Resource Value Test

1 There are seven wholesale electricity markets in the United States that are operated by an ISO or a regional transmission organization (RTO). The distinctions between ISOs and RTOs are subtle. For simplicity, throughout this paper we refer to either type of organization as an ISO.

2 California Public Utilities Commission. (2001). *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects*. Retrieved from http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf

3 National Efficiency Screening Project. (2017). *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*. Retrieved from https://nationalefficiencyscreening.org/national-standard-practice-manual/

(RVT). The long-established C-E tests from the CaSPM and the new RVT are summarized in Table 1, which is adapted from a similar table in the NSPM.

Table 1. Energy Efficiency Cost-Effectiveness Tests

Test Name	Question Answered	Summary of Approach
Participant Test (PT)	Will costs decrease for the person or business participating in the program?	Only considers the costs and benefits experienced by program participants
Ratepayer Impact Measure (RIM)	Will utility rates decrease?	Considers the costs and benefits that affect utility rates, including program administrator costs and benefits and utility lost revenues
Program Administrator Cost Test (PAC)[4]	Will the utility's total costs decrease?	Considers the costs and benefits experienced by the utility or program administrator
Total Resource Cost Test (TRC)	Will the sum of the utility's total costs and the participant's total costs (or energy-related costs) decrease?	Considers the costs and benefits experienced by all utility customers
Resource Value Test (RVT)	Will utility system costs be reduced while achieving applicable policy goals?	Considers the utility system costs and benefits plus those costs and benefits associated with achieving energy policy goals
Societal Cost Test (SCT)[5]	Will net costs to society decrease?	Considers all costs and benefits experienced by all members of society

Source: Adapted from National Efficiency Screening Project. (2017). *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*.

Although the C-E tests summarized in Table 1 were developed for use in evaluating energy efficiency programs, C-E testing for other DER programs and resources in the United States often uses one or more of the same tests.[6] For example, California uses modified versions of the TRC, PAC, RIM, and PT when considering utility requests to fund DR programs.[7] In Massachusetts, regulators at the Department of Public Utilities approved some utility proposals to include battery energy storage in energy efficiency and DR program plans after reviewing TRC test results that showed the proposals were cost-effective.[8] The specific categories of value streams included in the calculations vary from state to state, and often vary across the different types of DERs, even while using the same name (e.g., TRC) to describe the C-E test. The same is true for cost categories. Although this report emphasizes DER value streams, C-E tests always look at both costs and benefits. Adding DG to a congested area of the distribution system, for example, may trigger the need for upfront investment in incremental utility system capacity, whereas an energy efficiency or DR program may impose ongoing operational costs on the utility but require no incremental capacity investments.

DERs are capable of providing a wide range of value streams. To begin with, DERs are frequently installed and operated in ways that reduce energy costs for both the participants and their utilities. From the participant perspective, customers do not normally install DERs if doing so will increase their energy costs but may occasionally do so for environmental reasons. From the utility perspective, energy efficiency, DG, and DR resources will virtually always reduce the utility's energy supply costs, whereas energy storage resources can potentially decrease or increase utility energy costs depending on how they are operated and EVs will increase utility energy costs.

4 Another name for the PAC test is the Utility Cost Test. Because energy efficiency and other DER programs are sometimes managed by non-utility program administrators, we opt to use the PAC name throughout this paper.

5 The SCT is described in the CaSPM as a variant of the TRC but is treated by practitioners in many other states as an entirely separate test.

6 In December 2016, RAP produced a literature review and annotated bibliography for the CPUC on the use of C-E tests for evaluation of DERs. The documents were entered into the record in a CPUC proceeding. Shenot, J., Linvill, C., and Brutkoski, D. (2016). *Use of Cost-Effectiveness Tests for Evaluation of Distributed Energy Resources: A Literature Review*. The Regulatory Assistance Project. Retrieved from http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M176/K948/176948991.PDF. The NSPM is certainly a noteworthy reference, but it was published after RAP's literature review for the CPUC and is not included therein.

7 CPUC. (2016). *2016 Demand Response Cost Effectiveness Protocols*. Retrieved from http://www.cpuc.ca.gov/General.aspx?id=7023

8 Massachusetts Department of Public Utilities. (2019). D.P.U. 18-110 through D.P.U. 18-119. Retrieved from https://www.mass.gov/files/documents/2019/01/31/2019-2021%20Three-Year%20Energy%20Efficiency%20Plans%20Order_1.29.19.pdf

Some DERs also help utilities avoid generation capacity costs (e.g., through peak shaving DR programs), although again EVs could lead to increased costs in this area. The most obvious evidence for this assertion is the fact that energy efficiency and DR resources have successfully bid into ISO capacity markets where they are eligible. This provides adequate proof that those DERs are sometimes less expensive than other sources of generation capacity that would have to be procured in their absence. DG and energy storage DERs also have the potential to reduce generation capacity costs for utilities, although this depends on when the utility peak occurs (daytime or evening), how storage resources are charged and discharged by customers, and other factors.[9] DERs can also reduce the need for utility investment in transmission and distribution capacity, as we illustrate later in this report. For utilities operating within a competitive electricity market, reductions in wholesale market energy purchases will also result in price suppression. This "demand reduction induced price effect" (sometimes called DRIPE) may be a significant utility system value stream, but it is difficult to quantify because of barriers in obtaining proprietary energy bid data from utilities and ISOs.

The value streams noted above are merely a sampling. Appendix A provides background information on how various authors have categorized the full range of value streams specific to each type of DER. To date there is no accepted or authoritative list of value streams applicable to all DERs, and this paper does not attempt to establish one. But to ensure that the concept is understood, we can summarize the topic by offering in Table 2 an illustrative list of DER value streams.[10]

Quantifying the economic value of each value stream from each perspective can be difficult, inexact, and controversial. At the most basic level, quantitative values can be estimated using market prices as proxies or the values can be administratively determined by utilities or regulators. Each of these approaches is explained here.

Table 2. Illustrative List of DER Value Streams

Beneficiary	Value Streams
Utility system	Avoided energy costs
	Avoided generation capacity costs
	Avoided reserves or other ancillary services
	Avoided transmission & distribution system investment
	Avoided transmission & distribution line losses
	Avoided operations & maintenance costs
	Wholesale market price suppression
	Avoided renewable portfolio standard (RPS) compliance costs
	Avoided environmental compliance costs
	Avoided credit and collection costs
	Reduced risk
Participants	Electricity bill savings, credits, or revenues
	Participant health, comfort, and safety
	Participant resource savings (non-electric fuels, water)
	Increased resilience
Low-income customers	Reduced low-income energy burden[11]
Public	Public health benefits
	Energy security
	Jobs and economic development benefits
Environment	Environmental benefits

Source: Adapted from National Efficiency Screening Project. (2017). *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*.

Market-based values assume that competitive markets, where they exist, are the best proxy for the value of any good or service.[12] In the United States today, many regions have competitive wholesale markets for electric energy, generating capacity, transmission rights, and some ancillary services.[13] Competitive markets also exist in some jurisdictions for greenhouse gas and criteria air pollutant emissions

9 In February 2019 an aggregation of residential PV and storage resources cleared in the ISO New England capacity market, marking the first time such an aggregation has been awarded capacity market revenues. Gheorghi, I. (2019, February 8). Residential solar+storage breaks new ground as Sunrun wins ISO-NE capacity contract. *Utility Dive*. Retrieved from https://www.utilitydive.com/news/residential-solarstorage-breaks-new-ground-as-sunrun-wins-iso-ne-capacity/547966/

10 Although the NSPM focuses on energy efficiency, Appendix B of the *Manual* considers the costs and benefits of other DERs. Our Table 2 is adapted from Table 32 in Appendix B of the NSPM with minor additions and modifications.

11 The potential benefits of DERs for reducing low-income energy burdens are still largely untapped. Low-income customers can participate equally in most DR programs offered by utilities and often have access to more advantageous energy efficiency program benefits. But they also face greater hurdles to investing in energy efficiency and generally have few opportunities to install other DERs owing to prohibitive upfront investment costs.

allowances, and RECs.[14] Establishing a wholesale electricity market, an emissions allowance market, or a REC market does not automatically reveal economic value; market rules and procedures need to be carefully designed to define and compensate the value of various services that can be provided by DERs.

Administratively determined values are typically based on traditional methods for assessing utility costs of service, but in the case of nontraditional or difficult to quantify value streams (e.g., reduced risk or environmental benefits) it may be necessary to use assumed values or proxy values based on professional judgment. For example, regulators in Wisconsin require the use of an administratively determined proxy for the value of avoided greenhouse gas emissions as part of some C-E tests.[15] The administrative approach is used where competitive markets do not exist for a value stream.

A final key point to emphasize is that the economic value of many value streams can be time-dependent, location-dependent, or interdependent. For example, resources and actions that only reduce demand during off-peak hours may have a value of zero with respect to avoided generation capacity costs, whereas actions that reduce demand by the exact same amount during peak hours might have a high value. This is because the amount of capacity utilities procure depends on peak demand; reducing off-peak demand does not reduce generation capacity costs. Similarly, resources and actions in one location on the distribution system might alleviate a constraint and have a high value for avoided transmission and distribution system investment, but the same resources and activities in an unconstrained part of the grid might have no such value or even impose system costs. And the interdependency of value streams can be appreciated by considering that a west-facing PV array will generate less energy than a south-facing array but may have more capacity value if it is on a system that peaks in late afternoon hours.

12 Economists distinguish between price and value. The true value of any service to any individual customer is not the market price, but rather the maximum price the consumer would be willing to pay. If the price is equal to or less than the value, the consumer will purchase the service. If the price is higher than the value, the consumer will forego the service. Although prices and value are different, prices are commonly used as a proxy for the average value of a service across a broad group of customers.

13 An explanation of wholesale electricity markets is beyond the scope of this report. Interested readers can find a wealth of information about competitive electricity markets on the website of the Federal Energy Regulatory Commission at https://www.ferc.gov/market-oversight/mkt-electric/overview.asp

14 A REC is a tradable certificate that represents the property rights to the environmental and renewable attributes of one megawatt-hour (MWh) of electricity that is generated and delivered to the electricity grid from a renewable energy resource. Load-serving entities that are subject to a state RPS can use RECs to demonstrate that they have procured sufficient renewable energy to comply with those standards. Companies and individuals who wish to voluntarily make claims about use of renewable energy may also purchase RECs.

15 In 2010, the Public Service Commission of Wisconsin decided that a levelized carbon value of $30 per ton should be used in the benefit/cost modeling of energy efficiency programs based on their judgment that such a value served as a reasonable proxy for the expected future costs of expected carbon regulations that were proposed but not finalized at the time of the decision. A memo summarizing the Commission's decisions on energy efficiency evaluation is available in Docket 5-GF-191, Reference #137513, retrieved from http://apps.psc.wi.gov/pages/viewdoc.htm?docid=137513

III. The Potential Value of Combinations of DERs

Section II provided background information on DER value streams and methods for testing the cost-effectiveness of DERs. In this section, we explain how combinations of DERs can potentially have different values than individual DERs.

Any PV system, installed in isolation without other DERs, is limited in the services and value streams it can provide. But when PV is combined with other DERs, new synergistic opportunities arise such that the total value of a combination of PV and other DERs can be greater than the sum of the values of each component in isolation. This paper does not attempt to catalog all the ways in which other DERs can complement PV, and vice versa, but it is helpful to briefly mention a few of the more significant examples[16] of additive or synergistic benefits arising from DER combinations.

- **PV + Storage.** When energy storage is added to a PV system, the primary limitation of PV — that it can only provide power when the sun shines — is alleviated. Customers can use power as it is generated or store it for later use. They can also draw power from the energy storage system when it is most valuable to do so. From the customer or "participant" perspective, this creates opportunities for energy cost arbitrage (charge the batteries with PV and use grid power when grid power is cheap, and power end uses with PV or stored energy when grid power is expensive) and demand charge reductions (reduce daytime peaks with PV and nighttime peaks with stored energy). With an additional investment in microgrid technology, this combination of DERs can also enable resilience. Customers can power critical loads during grid outages, not only in daytime with their PV system, but also through the night with stored energy.
- **PV + EV.** When an EV replaces a fossil-fueled vehicle, the environmental impacts (as viewed from the societal perspective) will depend on whether the electricity that fuels the EV is generated from sources that emit less than burning gasoline or diesel fuel. Most recent studies indicate that the impact will generally be positive and will improve over time as the generation of electricity increasingly comes from emissions-free renewables.[17] In any event, an EV that is charged with power generated by PV will have maximum environmental benefits because it replaces fossil-fueled transportation with a zero-emissions fuel. Viewed from the utility perspective, combining an EV with PV may also reduce the need for capacity upgrades to the transmission and distribution systems, if the electricity for the EV can be mostly or entirely provided by onsite generation.
- **PV + DR.** The same technologies and techniques that are used for DR in isolation can be combined with PV to create even more value. For example, flexible loads such as electric water heating, air conditioning, electric space heating, and pool pumps can be programmed to take advantage of times when the generation from a customer's PV system exceeds their momentary demand for other end uses. From the participant's perspective, this can be a valuable form of DR especially if the customer does not receive full retail rate compensation for excess generation from their PV system. Or, if a customer is on a demand charge rate, the combination of PV and DR might enable the customer to shift evening peak loads to daytime hours when the PV system generates electricity, reducing both energy and demand charges. From a utility or ISO perspective, this combination of DERs can be especially valuable. Although traditional DR programs are managed almost exclusively to shave peaks during system capacity shortages, newer forms of DR can "shape, shift, and shimmy" flexible loads to better integrate large amounts of generation from solar, wind, and other variable energy resources. (These new forms of DR are explained in Section D of Appendix A.) Combining PV and DR creates value for all ratepayers in the form of avoided energy, capacity, or ancillary service costs.

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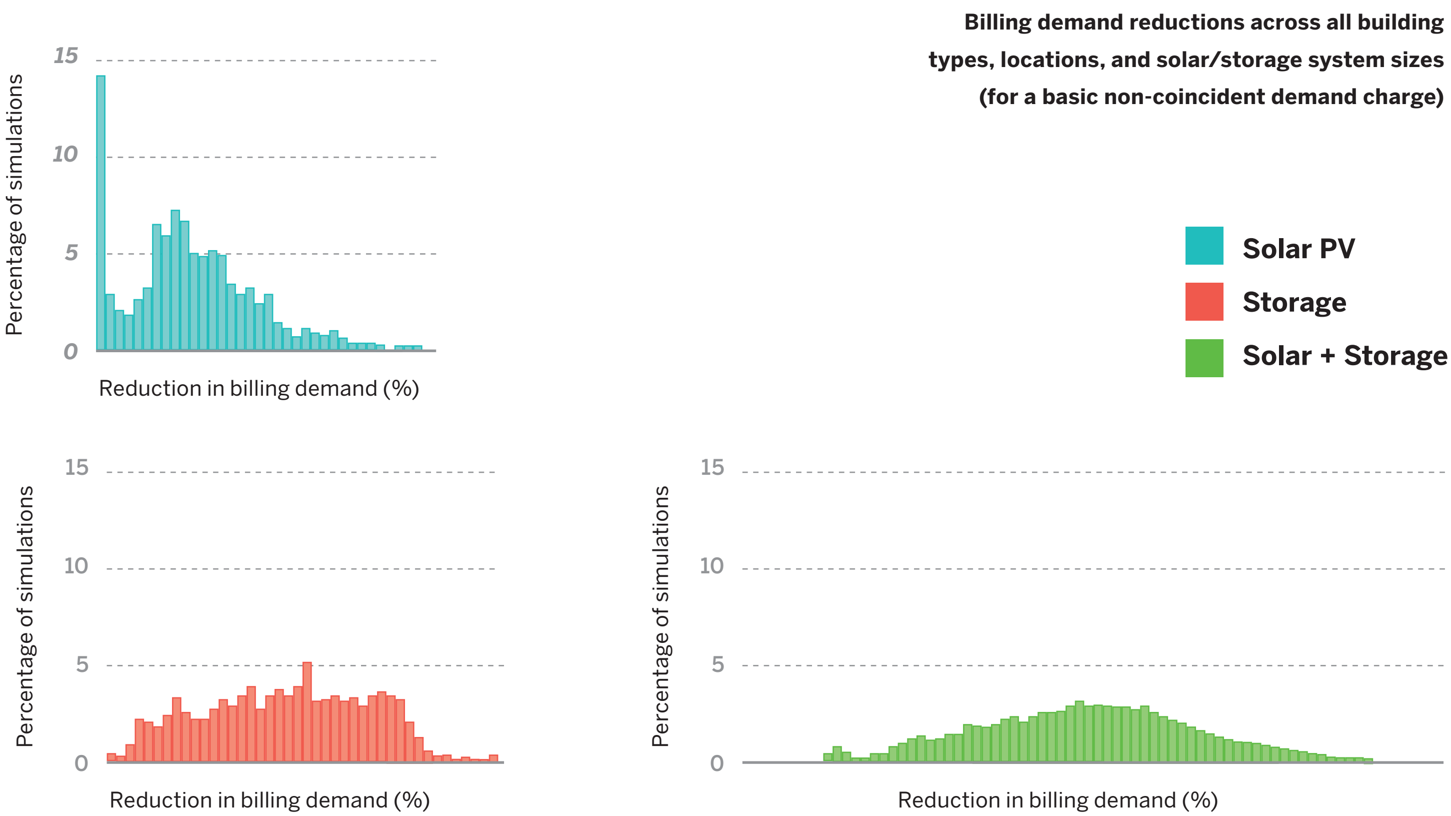
16 A more complete review of the "solar plus" literature can be found in O'Shaughnessy, E., Cutler, D., Ardani, K., and Margolis, R. (2018, October 15). Solar plus: A review of the end-user economics of solar PV integration with storage and load control in residential buildings. *Applied Energy*, Volume 228, pp 2165-2175. The examples presented here are illustrative rather than exhaustive.

17 The Union of Concerned Scientists, for example, reported in 2015 that "Driving an average EV results in lower global warming emissions than driving a gasoline car that gets 50 miles per gallon (MPG) in regions covering two-thirds of the U.S. population, up from 45% in our 2012 report. Based on where EVs are being sold in the United States today, the average EV produces global warming emissions equal to a gasoline vehicle with a 68 MPG fuel economy rating." Nealer, R., Reichmuth, D., and Anair, D. (2015). *Cleaner Cars from Cradle to Grave: How Electric Cars Beat Gasoline Cars on Lifetime Global Warming Emissions*. Union of Concerned Scientists. Retrieved from https://www.ucsusa.org/sites/default/files/attach/2015/11/Cleaner-Cars-from-Cradle-to-Grave-full-report.pdf

Figure 1. Synergistic Effect on Demand Charges for PV and Storage



The figure shows the distribution of average monthly billing demand reductions across all building types, locations, solar sizes, and storage sizes. Each data point is the average percentage reduction, for a single load/solar/storage combination, across all months of the 17-year historical weather period.

Source: Gagnon et al. (2017).

There is ample evidence that the types of synergistic effects described previously are not merely hypothetical. For example, a study by the Lawrence Berkeley National Laboratory (LBNL) and the National Renewable Energy Laboratory (NREL) found, as shown in Figure 1, a median reduction in monthly demand charges for commercial customers who combined PV with storage of 42%, compared to just 8% for PV alone and 23% for storage alone.[18]

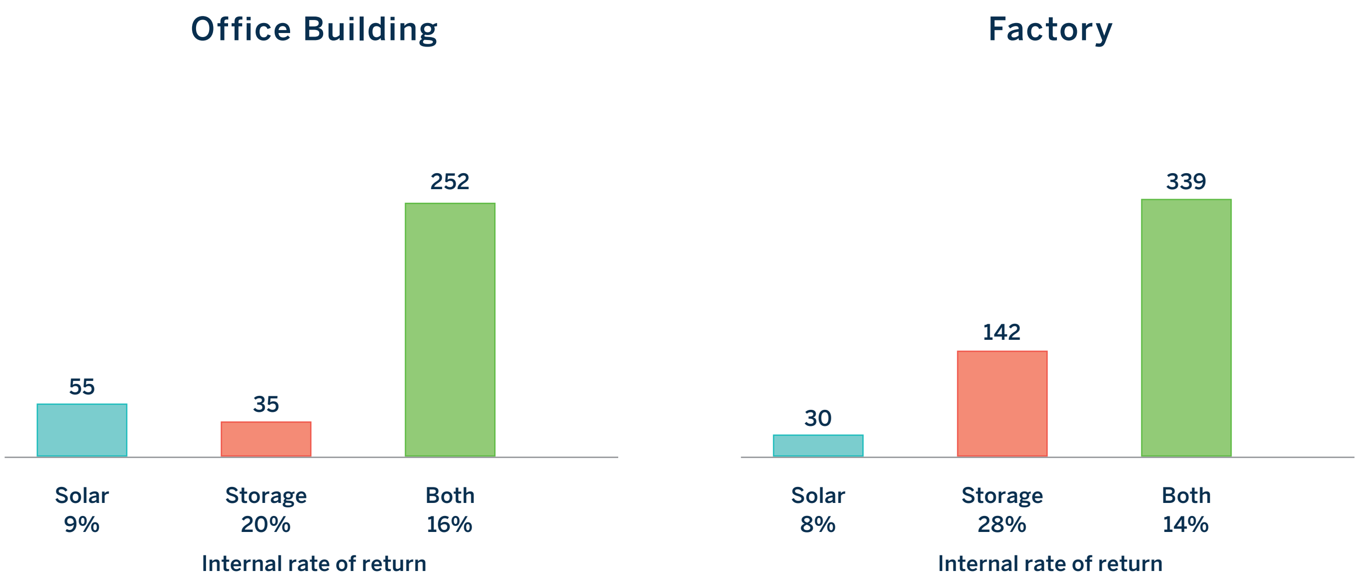
Looking beyond demand charges, a 2015 study by the management consulting firm Woodlawn Associates found strong synergistic effects on net present value (NPV) and internal rate of return (IRR) for hypothetical installations of PV and storage on commercial buildings in California, Hawaii, or New York.[19] One such example from that report is presented in Figure 2 on the next page.

Although combinations of DERs can result in additive or even synergistic benefits, it must also be understood that any given DER might not be able to capture all of the potential value streams. In other words, DER value streams are not necessarily additive. This is especially true for energy storage resources. Storage may be used to defer distribution capacity investment, for example, but using storage for that purpose may limit its value for avoiding energy cost or for meeting resource reserve requirements. So DERs, like storage, are likely

18 Gagnon, P., Govindarajan, A., Bird, L., Barbose, G., Darghouth, N., and Mills, A. (2017). *Solar + Storage Synergies for Managing Commercial-Customer Demand Charges*. Lawrence Berkeley National Laboratory. Retrieved from https://emp.lbl.gov/publications/solar-storage-synergies-managing

19 Sussman, M., and Lutton, J. (2015, November 17). Energy Storage 301: Solar + Storage Economics [Blog post]. Woodlawn Associates. Retrieved from https://woodlawnassociates.com/energy-storage-301/

Figure 2. Synergistic Effects on Net Present Value and Internal Rate of Return for PV and Storage



Source: Sussman and Lutton. (2015, November 17). *Energy Storage 301: Solar + Storage Economics*.

to not be valuable for a number of value streams precisely because they are valuable for a particular value stream that the owner or operator has prioritized. Thus, the C-E of a program that attracts storage to defer distribution system investment would be evaluated differently (or have different constituent value streams with possibly different values for the same value stream) than a program that attracts storage to provide capacity, frequency, and energy to the wholesale market.

IV. Current Mechanisms for Capturing the Value of DERs

Sections II and III explained the concept of value streams and offered examples of how combinations of DERs can create synergistic value. In this section, we describe the main mechanisms currently in place for capturing value.

Most of the value streams mentioned earlier are either inherent to certain types of DERs or the DERs can be operated in such a way as to create those benefits. However, DERs generally get installed and operated only when they are cost-effective from the participant's perspective — that is, the monetary value to the customer exceeds the cost to the customer.[20] A combination of PV and storage might inherently have measurable value from the utility perspective in reducing generation capacity needs, but if the customer receives no compensation for that inherent value, if they can't "capture" it, then it will be harder for the customer to justify the cost of installing those DERs.

Broadly stated, there are at least four common mechanisms for compensating customers: a) tariffs or bill credits, b) market revenues, c) PPAs or contracts, and d) one-time payments or credits.

A. Tariffs or Bill Credits

Customers who have DERs can be directly or indirectly compensated by their utility via their utility bill. To begin with, the rate design and the prices in a traditional utility tariff create an inherent value and compensation to the customer for any action that reduces billing determinants. When a customer reduces their energy consumption, the utility avoids energy costs and potentially some other costs, and the customer pays less on their bill. When a customer on a demand rate reduces their on-peak demand, the utility potentially avoids capacity costs and the customer is compensated through a reduction in their utility bill. Thus, even a "traditional" retail rate design will partially compensate DER owners for the values they provide to the utility system. The amount of compensation, however, may bear little resemblance to the value provided.

Many utilities also offer tariffs that more accurately compensate customers for the utility system value of DERs — and especially DR actions. These include real-time pricing, critical peak pricing, variable peak pricing, other TOU rates, and PTRs.[21] Each of these tariffs recognizes that utility system costs vary with time and sends a price signal that consumption during peak hours is much more costly than at other times (or conversely, actions that reduce demand during peak hours are much more valuable than similar actions taken off peak). In other words, these time-varying rate designs better align customer compensation with utility system avoided costs (value) than a rate design in which prices do not vary with time. In addition to DR actions, energy storage and some energy efficiency measures can reduce consumption during peak hours to take advantage of these time-varying rate designs.

Almost all utilities offer special tariffs to customers who have PV or other forms of DG. The most common of these are NEM and net energy billing tariffs.[22] According to the Database of State Incentives for Renewables & Efficiency (DSIRE) hosted by the North Carolina Clean Energy Technology Center, nearly 40 states have adopted policies requiring some or all utilities to offer NEM or net energy billing tariffs.[23] A relatively small number of utilities instead (or additionally) offer VOS tariffs or FITs. VOS tariffs are listed in DSIRE for just one state (Minnesota) and one municipal utility (Austin Energy in Texas), whereas FITs are listed for utilities in just four states and one territory. Community solar programs that provide bill credits to participating customers were rare just a few years ago, but as of October 2018 there were community solar projects in more than 40 states.[24]

For each DG tariff or community solar program, the utility or its relevant regulatory authority decided how much credit customers should receive on their bill for each kWh

20 There are, of course, exceptions to this general rule. Some customers undoubtedly install DERs for non-economic reasons such as reducing environmental impacts.

21 FERC, in its annual staff reports on DR and advanced metering, defines DR to include time-based rate programs. See: Federal Energy Regulatory Commission. (2017). *Assessment of Demand Response and Advanced Metering - Staff Report*. Retrieved from https://www.ferc.gov/legal/staff-reports/2017/DR-AM-Report2017.pdf

22 For a primer on DG compensation, see: Zinaman, O., Aznar, A., Linvill, C., Darghouth, N., Dubbeling, T., and Bianco, E. (2015). *Grid-Connected Distributed Generation: Compensation Mechanism Basics*. National Renewable Energy Laboratory. Retrieved from https://www.nrel.gov/docs/fy18osti/68469.pdf

23 Data were current as of November 2017. Details can be found on the DSIRE website at http://www.dsireusa.org/

24 Based on Solar Energy Industries Association data at https://www.seia.org/initiatives/community-solar

of generation from the DG system. In many cases, these decisions have been informed by an investigation into the streams of value that a DG system typically provides from the utility perspective. A VOS tariff is explicitly designed to offer compensation that reflects utility system value, possibly supplemented by societal values, whereas a FIT (which is only rarely available in the United States) is usually designed to incentivize DG installations by offering compensation that exceeds the customer's costs, regardless of their value to the utility system.[25] NEM and net energy billing tariffs are generally designed to be simple; they offer credit at the customer's retail energy rate for every kWh the customer generates and consumes. However, NEM and net energy billing tariffs will also specify how much credit the customer receives for net excess generation (i.e., generation during a specified interval that exceeds consumption during the specified interval), and that credit is often set at a level intended to compensate the customer for specific utility and societal value streams. Each type of DG tariff will also specify whether the customer or the utility takes ownership of any RECs; if it is the utility, the compensation afforded to the customer may reflect this additional value because the customer is, in effect, selling to the utility the right to claim the renewable attributes of each kWh of renewable generation.

In March 2017, the New York Public Service Commission (NY PSC) issued an order that broke new ground for compensating DERs for the values they provide to the utility system.[26] In that order, the New York PSC reached a critically important conclusion that is undoubtedly applicable in many jurisdictions:

> *The Commission also recognizes that existing DER business models are well-established and based largely on net energy metering (NEM). These business models reflect the capabilities and needs of the electric system at the time they were designed and they appropriately served to open up markets and drive initial development. But such business models and NEM in particular are inaccurate mechanisms of the past that operate as blunt instruments to obscure value and are incapable of taking into account locational, environmental, and temporal values of projects. By failing to accurately reflect the values provided by and to the DER they compensate, these mechanisms will neither encourage the high level of DER development necessary for developing a clean, distributed grid nor incentivize the location, design, and operation of DER in a way that maximizes overall value to all utility customers. As such, they are unsustainable.*

Based on that conclusion, the New York PSC ordered regulated New York utilities to transition some DG customers away from NEM tariffs, and toward "Phase One Value Stack" compensation.[27] Compensation under the Phase One Value Stack is based on specific utility system and societal values associated with a DG customer's net hourly injections of power into the utility's distribution system: a) energy value at the time of injection, inclusive of avoided line losses; b) capacity value, based on performance during the peak hour of the previous year; c) environmental value, based on the higher of REC procurement prices or the social cost of carbon; and d) demand reduction value and locational system relief value, based on the utility's marginal cost of service study and the DG system's performance during the utility's 10 peak hours. To assist customers and developers with understanding what to expect if they install a new system, the New York state energy office created an online solar value stack calculator.[28]

Finally, Arizona Public Service (APS) experimented with a completely different kind of PV bill credit as part of an effort to test and evaluate the utility system value of residential solar installations with advanced inverters. Under the Solar Partner program, 1,600 customers allowed APS to install, own, and operate a PV system on the customer's roof in exchange for a $30 per month bill credit. They essentially leased their rooftops to the utility. The utility is now free to experiment with ways to

25 In 2015, NREL and the Smart Electric Power Association jointly published a guide on designing and implementing VOS tariffs that provides useful insights on how tariffs can reflect the multiple value streams of PV. See: National Renewable Energy Laboratory. (2015). *Value of Solar: Program Design and Implementation Considerations*. Retrieved from https://www.nrel.gov/docs/fy15osti/62361.pdf

26 State of New York Public Service Commission. (2017). *Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters*. Cases 15-E-0751 and 15-E-0082. Retrieved from http://on.ny.gov/2n7xYDR

27 Compensation for other DERs is to be addressed in subsequent phases of this transition, not yet decided by the New York PSC.

28 The calculator can be accessed at https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Solar-Value-Stack-Calculator

capture maximum utility system value, while customers enjoy a bill credit for 20 years with no investment or maintenance costs.

The basis for compensation under each of these DG tariffs is summarized in Table 3.

Table 3. Special Tariffs for DG Customers

Type of Tariff	Basis for DG Compensation
Net Energy Metering	For all self-consumption and excess generation, customer's full retail energy rate[29]
Net Energy Billing	For self-consumption, customer's full retail energy rate For excess generation, a fixed rate usually based on average values for a limited set of value streams and usually less than the full retail rate
Feed-in Tariff	For all generation, a fixed incentive rate that is not typically based on value streams
Value of Solar	A fixed rate that reflects the sum of the annual average values of different value streams (can be applied to all generation or to excess generation only where self-consumption is compensated at the full retail energy rate)
Value Stack (e.g., NY Phase One Value Stack)	For net hourly self-consumption, customer's retail energy rate For net hourly excess generation, sum of the values of different value streams, which can vary with time and location
Fixed Credit (e.g., APS Solar Partner)	Fixed monthly amount, not directly related to value

Source: Author analysis

A completely different kind of tariff, a "standby" or "partial requirements" tariff, is typically offered to customers who have CHP systems or microgrids that consist of combinations of DERs. These are usually industrial or large commercial customers (e.g., universities) that have a need for both the electricity and the steam produced by a CHP unit or the added resiliency of a microgrid. Customers who have a CHP system or a microgrid may have predictable loads and predictable generation profiles under normal conditions, but the generators may not be sized to meet all their electric power needs, and the systems must occasionally be shut down for scheduled maintenance or for unscheduled emergencies. Under a standby tariff, the customer pays different rates to the utility for each of these three circumstances — supplemental power (the portion of energy needs in excess of what their system produces), maintenance power, and emergency backup power — that reflect the utility's cost of providing those three distinct kinds of service.[30]

In addition to standby tariffs, some utilities now offer tariffs to customers who have specific combinations of DERs, but this is a new phenomenon and more the exception than the rule. Hawaii Electric Company, for example, offers a Smart Export tariff to customers who have combinations of PV and energy storage. The utility encourages customers to charge their batteries during the daytime with the customer's PV system, and then discharge the batteries during evening peak hours after the sun has set. Excess energy from the customer's premises receives no compensation between 9 a.m. and 4 p.m. but receives 11 to 21 cents/kWh (depending on the location) in all other hours.[31] Tariffs for other DER combinations could conceivably appear in the coming years. For example, some utilities have offered customers who have EVs the choice of a separately metered and billed EV charger, or a "whole-house" rate. A whole-house rate option (or the equivalent for a commercial or industrial customer) might be attractive to customers who have combinations of EVs and other DERs (e.g., PV or DR) because it allows those customers to schedule EV charging not merely during off-peak hours for the system, but also in conjunction with times of excess PV generation or times when flexible loads can be curtailed.

Designing tariffs for combinations of DERs is a promising way to recognize the specific values that can be obtained, but the challenge for utilities (and regulators) is to do so while ensuring that the tariffs remain simple enough for customers to understand. In some cases, it may be necessary or advantageous to forego some value to retain simplicity.

29 In many NEM tariffs, credits for excess generation expire after a period of time (e.g., one year) and may lose all value or be purchased at a price less than the customer's full retail energy rate.

30 For more information on designing standby rates, refer to: Selecky, J., Iverson, K., and Al-Jabiret, A. (2014). *Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States*. Prepared by Brubaker & Associates, Inc. and the Regulatory Assistance Project for Oak Ridge National Laboratory. Retrieved from https://info.ornl.gov/sites/publications/files/pub47558.pdf

31 Details at https://www.hawaiianelectric.com/products-and-services/customer-renewable-programs/smart-export

B. Market Revenues

Much of the existing literature regarding DER combinations is framed in terms of "solving integration problems close to home" — that is, at the distribution network or utility footprint levels.[32] However, it is also worth considering how DER combinations can provide services to the regional ISO wholesale markets, help to support renewable integration at that wider regional level, and enjoy revenue corresponding to the bulk power system value of those services.[33] Inverter-based technologies like PV and storage and electric resistance devices like electric water heaters have the capability of providing fast frequency response and have the ability to help shape and shift load, both of which can be valuable to wholesale markets. Qualifying these resources to provide the full suite of their capabilities to wholesale market operators adds value for the resource owner and keeps costs down for all consumers by increasing supply of needed resources.

The seven ISOs existing in the United States today operate wholesale electricity markets in which various market participants compete to provide energy, capacity, and ancillary services to load-serving entities (utilities and competitive retail energy suppliers). In principle, if the owners of DERs can meet eligibility requirements and successfully compete with other market participants, they can receive monetary payments for the values they provide to the bulk power system.[34] In practice, the ISO markets vary in terms of their eligibility rules and how they compensate capacity and specific ancillary services and these market rules can restrict DER participation. For example, each ISO includes, among its eligibility rules, minimum size requirements for market participants. DERs, especially those owned by residential customers, are often too small to participate in wholesale markets on their own. However, if multiple DERs under the control of an aggregator of retail customers can meet the size requirement collectively, they may be able to participate.

FERC, which has jurisdiction over almost all ISO markets[35], established rules in Order 719 (2008) requiring each ISO to amend its tariffs as needed to allow for participation of DR aggregators in organized wholesale electricity markets, unless such participation is limited by state and local regulatory authorities.[36] Because of Order 719, DR resources have been more active in wholesale markets than other DERs. ISO New England and PJM (an ISO serving utilities in mid-Atlantic and Midwest states) in particular have seen robust participation by aggregated DR resources in their energy and forward capacity markets. As of April 2019, FERC had an open proceeding regarding whether to similarly allow aggregation of other DERs.[37] There are far fewer examples, although very interesting ones, of DERs competing in an ISO to provide ancillary services.

Distributed solar PV resources may face some particular hurdles to participation as dispatchable resources in ISO markets. In states with net metering regimes that are favorable to distributed solar, there is likely to be limited scope and dampened incentive for direct participation in ISO energy markets, even if suitable aggregation and participation models are in place, because the value to customers in self-supplying their energy and avoiding retail energy charges will usually exceed the value of that energy in wholesale electricity markets.[38] However, the evolution of standards for the interconnection of DG resources into the power grid should help unlock additional capabilities of DG, helping to facilitate, for example, participation of aggregated rooftop solar in ISO ancillary service markets.

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32 For example, see Cliburn, J., Howard, A., and Powers, J. (2017). *Solar Plus Storage Companion Measures for High-Value Community Solar: A Guide for Utility Program Planners*. Community Solar Value Project. Retrieved from https://www.communitysolarvalueproject.com/uploads/2/7/0/3/27034867/2017_09_30_final_6_solar__storage_guide.pdf

33 In this discussion we focus on DER participation in ISO markets. Aggregated DERs may effectively participate in non-ISO wholesale trades in other parts of the country, although these would largely be aggregated and mediated by vertically integrated utilities.

34 Bulk power system costs are recovered from the load-serving entities and utilities, who in turn pass their costs through to retail customers. Thus, these value streams are relevant from all perspectives and in all C-E tests.

35 The ERCOT market is primarily regulated not by FERC but by the Public Utility Commission of Texas, because the interconnection there is entirely within the state of Texas and does not affect interstate commerce.

36 18 CFR 35.28(g)(1)(iii).

37 Refer to FERC Docket Nos. RM18-9-000 and AD18-10-000.

38 For example, retail rates in the United States averaged 13.0 cents per kWh for residential customers, 10.6 cents for commercial customers, and 6.9 cents for industrial customers in November 2018. Throughout the same month, wholesale energy rates remained below 7.5 cents per kWh everywhere in the country except New England, where they briefly peaked (for a single day) at 12.8 cents per kWh. Data from the U.S. Energy Information Administration's *Electricity Monthly Update* for November 2018.

Market opportunities could be further expanded by creating participation models for combinations of different types of DERs; for example, PV combined with demand response or storage could offer a higher guarantee of availability during system peaks.

In just the past few years, several state PUCs have begun to discuss whether to create markets for electricity services at the distribution system level. These markets could potentially be operated by the local utility serving as a distribution system platform provider or by an independent distribution system operator. The role of a distribution system platform provider or an independent distribution system operator would be to facilitate and enable market access and transactions among customers, aggregators, and the distribution utility. Although this kind of market does not exist anywhere in the United States today, it is actively under consideration in New York and California and could someday provide another avenue for DER owners to capture utility system value through market revenues.[39] For example, inverter-based technologies could potentially provide voltage support to distribution markets.

Market opportunities could be further expanded by creating participation models for combinations of different types of DERs and not just aggregations of a single type of DER. For example, current ISO rules assign a capacity value for PV resources that is less than the rated capacity of the panels, in recognition of the fact that the full rated capacity of the panels will not be available during system peak events if those events happen on cloudy days or outside of daylight hours.[40] However, if PV is combined with DR or energy storage resources, the owner of the resources or an aggregator could conceivably guarantee that a higher percentage of the PV system's rated capacity (perhaps even 100%) would be available during system peaks by deploying DR or discharging energy storage resources if necessary to fulfill that guarantee. This could make it possible for PV resources to receive a higher capacity credit than they would otherwise receive — but only if market rules allow for the participation of combinations of resources.

Finally, PV and other qualifying DG resources can also capture utility system or societal value by participating in REC trading markets. The value of a REC will vary from state to state, in large part due to the existence and stringency of state RPS requirements and the surplus or scarcity of eligible RECs needed for compliance. REC values associated with some DG resources can be significantly higher in states where the RPS law includes a "carve-out," meaning that a portion of the overall renewable energy procurement obligation must be satisfied by those resources. For example, in 2016 the price of RECs purchased for voluntary purposes averaged approximately $0.35 per MWh nationwide, whereas RECs purchased for RPS compliance purposes in New England states were closer to $35.00 per MWh and solar RECS purchased for compliance with a solar RPS carve-outs were worth hundreds of dollars per MWh in several states.[41] However, the ability to capture REC value from markets may be limited for a couple of reasons. First, customers may perceive that the transaction costs for learning how REC markets work, registering a small renewable generator, and recording their generation may exceed the market value of those RECs. (This is less of an issue for third-party–owned systems that are leased to customers, because the third party will often own many small systems that aggregate to a much larger value.) Second, customers who sell their RECs technically lose the right to claim that their operations are

39 New York in particular appears committed to transitioning its regulated utilities into a DSP role. The state's own formulation of the DSP concept is described in the "REV Track One Order": State of New York Public Service Commission. (2015). *Order Adopting Regulatory Policy Framework and Implementation Plan*. Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. Retrieved from https://nyrevconnect.com/rev-briefings/track-one-defining-rev-ecosystem/

40 The Midcontinent ISO and PJM Interconnection, for example, assign a capacity credit to solar resources that is roughly half the rated capacity of the panels.

41 O'Shaughnessy, E., Heeter, J., Cook, J., and Volpiet, C. (2017). *Status and Trends in the U.S. Voluntary Green Power Market (2016 Data).* National Renewable Energy Laboratory. Technical Report NREL/TP-6A20-70174. Retrieved from https://www.nrel.gov/docs/fy18osti/70174.pdf

powered by renewable electricity — that right is transferred to the buyer of the REC. Many corporate owners of DG systems are motivated by such claims. Thus, many small renewable generators do not seek to capture market value from REC trading markets.

C. PPAs or Contracts

Utilities often enter into PPAs or other types of contracts with independent power producers or third-party energy service companies to provide energy, capacity, or ancillary services. The terms and conditions of these contracts may be determined through bilateral negotiations between the two parties or through a utility procurement program that awards contracts to the lowest bidders. Utilities can compensate DER owners for different value streams (e.g., energy value and REC value) separately, but more commonly they offer compensation via bundled, fixed price per kWh rates. It is also possible for owners of PV and other renewable DG resources to sell "undifferentiated" power to a utility via a PPA and sell their RECs to another party via a separate contract.

In 2018, Public Service Company of Colorado, an affiliate of Xcel Energy, signed PPAs for new utility-scale solar resources at levelized prices that averaged $23 to $27 per MWh. At the same time, the company signed PPAs for combinations of solar and storage at average levelized prices of $30 to $32 per MWh. Although these PPAs were for utility-scale resources rather than DERs, what is important to note is that the company was willing to pay more for the combined resources in recognition of the additional capacity and ancillary service values that those combinations could offer. The same thinking could conceivably be applied in future procurements by this company or by other utilities to combinations of distributed solar and distributed storage.

D. One-Time Payments or Credits

The federal government and many state and local jurisdictions offer or require utilities to offer one-time tax credits, rebates, upfront incentives, and other forms of compensation to DER owners that often are not tied to utility or wholesale market revenues. There are many varieties and examples of these one-time payments, including the federal investment tax credit for PV, state and federal tax credits for new EV purchases, customer rebates for energy efficient appliances, and upfront bill credits for customers who participate in a utility's direct load control DR program. All these options provide compensation to DER owners that is intended to reflect in some way the value those DERs bring to the utility system or to society.

As described previously for tariffs, new options are beginning to emerge for combinations of DERs. For example, when energy storage systems are paired with and charged by onsite PV, all or a portion of the energy storage capital investment is eligible for the federal investment tax credit for PV, whereas a standalone investment in storage is not eligible. Another example comes from Minnesota, where Steele-Waseca Cooperative Electric's Sunna Project combines a community solar program with a controllable electric water heater DR program.[42] Customers who agree to enroll in the DR program can subscribe for the output of one 410-watt PV panel for just $170, whereas customers who forego the DR program pay $1,225 for the same subscription. The cooperative offers this discount for DR program participants because the DR program is extremely valuable to the utility in managing its costs of service and could become even more valuable as more variable generation (like PV) is added to the grid.

42 Details at https://swce.coop/swce-field-services/renewables/

V. Examples of Use Cases for Combining PV With Other DERs

Section III offered examples of how combinations of DERs can theoretically create synergistic value, and Section IV explained the main mechanisms for capturing that value. In Section V, we provide real-world examples of "use cases" that explain why a customer might install a combination of PV with other DERs. Experience to date suggests that some DER use cases are proving more attractive (or practical) than others, and some value streams are being captured much more frequently and much more completely than others. One goal of this approach is to briefly illustrate which values of DER combinations can be captured today, which cannot, and what barriers exist to capturing additional value.

A. Use Case 1: Installing DERs to Earn Wholesale Electricity Market Revenues

This use case looks at how ISO participation models and compensation mechanisms are evolving — and might continue to evolve — to recognize and properly compensate those services provided to the transmission grid by DERs.

Most individual DER installations are too small to meet the ISOs' current minimum bid thresholds for market participation. As noted in Section IV, FERC Order 719 requires ISOs to allow aggregations of DR resources to participate in wholesale markets, but similar requirements are not currently in place for aggregations of other DERs. This is why, in practice, DER participation in wholesale markets has been dominated so far by DR resources. To the extent storage resources have participated in wholesale markets to date, it has largely been under participation models designed for DR, although this is changing, given FERC's 2018 ruling that each ISO must develop participation models designed specifically for storage resources.[43]

It is worth examining some of the nascent DER participation models to inform discussion of how these might evolve — perhaps to allow for better participation of combinations of PV with other DERs. In the remainder of this section, we look at participation models for DERs as they are developing in the CAISO markets. There are several ways for DERs to participate in CAISO. As in some other ISOs, participation for DR is the most well established, but CAISO has also been a leader in creating new participation models tailored for storage, including aggregated storage. Although there has been great interest in these participation models, overall resource participation remains quite limited.

CAISO's **proxy demand resource (PDR)** participation model is for resources that can be dispatched to reduce demand, such as traditional DR load curtailment. Storage resources have also participated, although PDR does not allow for injection of energy into the grid. (The cost of energy for recharging of a battery is determined by the customer's usual retail rates.) The model allows for traditional metering at the site level as well as submetering for compensation purposes. This means, for example, that the resource contribution can be measured at the battery level (although the metering and submetering is not visible to the ISO in real time). The resource is evaluated with respect to a baseline.[44] Resources can be aggregated from multiple sites. PDR allows for resource participation in the day-ahead, real-time, and ancillary service markets. In addition to revenue from CAISO markets, these resources can provide participant value onsite, including by helping the customer reduce demand charges.

Participation under the PDR has been quite limited but has grown rapidly. In 2017, the amount of registered resources under the PDR model was 270 MW, up from 160 MW the previous year. Of this amount, a small but growing share has been bid into the market. In turn, only a small fraction of the bids was low enough in the bid stack to be dispatched. Nearly all the PDR bids were at (or close to) CAISO's $1,000/MWh cap (the highest price that any resource is allowed to bid).[45] It is reasonable to expect that, as this resource develops, PDR bids at lower levels will become more prevalent, allowing for greater use of the resource.

43 FERC. (2018). *Order No. 841: Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*. Docket Nos. RM16-23-000; AD16-20-000. Retrieved from https://www.ferc.gov/media/news-releases/2018/2018-1/02-15-18-E-1.asp

44 Rothleder, M. (2017, March 8). *CA Distributed Energy Resource Models* [Presentation before the Northwest Power and Conservation Council DR Advisory Committee]. CAISO.

45 CAISO. (2018). *2017 Annual Report on Markets Issues & Performance*. p 36. Retrieved from http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf

Current discussion for further evolution of PDR includes relaxing the restriction that resources only reduce demand. That is, PDR resources could be allowed to bid to increase consumption at times when energy is plentiful on the grid (such as midday when the sun is strong) and CAISO energy market prices are negative at the closest LMP node. If CAISO were to select the bid for dispatch, then the resource would be paid for consumption. Similarly, PDR may be expanded to allow resources to provide regulation down (under CAISO's frequency regulation ancillary service market) by increasing consumption.[46]

A closely related participation model is the **reliability demand response resource (RDRR)** participation model, which is, as the term "reliability" suggests, intended to provide emergency support to maintain reliability. Unlike the PDR model, an RDRR can only bid on an economic basis into the day-ahead market, not the real-time or ancillary service markets.[47] When CAISO declares an emergency, uncommitted RDRRs can make themselves available for $950/MWh to $1,000/MWh (95 to 100% of the bid cap). In 2017, RDRR resources available for dispatch by CAISO totaled approximately 1,023 MW, down from 1,320 MW in 2016, but up from zero in 2014. CAISO dispatched RDRRs during four intervals in 2017.[48] Both PDR and RDRR are based on a counterfactual baseline that precludes participating in both, so a resource can't participate in both the PDR and RDRR markets.

Whereas the PDR and RDRR participation models can accommodate aggregations that include combinations of DR and storage resources, neither model allows for injections of energy into the grid and thus they exclude participation by PV resources.

CAISO's **non-generator resource (NGR)** participation model is specifically designed for storage or storage-like resources — that is, resources capable of rapidly shifting between injecting into or withdrawing energy from the grid — including distribution-level storage. NGRs are more like traditional generators than PDRs in the sense that they are able to inject energy into the grid and earn revenue by providing a wide range of services to CAISO, including provision of energy, reserves, and regulation services in the day-ahead, real-time, and ancillary service markets. In addition, NGRs (whether participating individually or in aggregations) are like traditional generators in that they are visible to, and accessible for direct communication with, the ISO as distinct resources (as opposed to PDRs which, from the ISO point of view, just affect net load). Accordingly, NGRs do not need to rely on baselines to measure performance.

The NGR participation model appears to be in line with FERC's Order 841, in that it:

- allows a storage resource to provide all services it is capable of providing;
- allows a storage resource to be dispatched;
- accounts for the physical and operational characteristics of electric storage resources;
- has a minimum size threshold below 100 kW; and
- allows a storage resource to resell energy back to the wholesale market at the wholesale locational marginal price.[49]

Market participants who want to create and offer aggregations of NGRs to the market must follow CAISO's rules and act as DER Providers (DERPs). A DERP can:

- mix together DER types, such as battery storage, DR, PV and other types of DG, and EV charging stations;
- mix together DERs across nodes (although all must be within the sub-load aggregation point level); and
- offer aggregations as small as 0.5 MW.[50]

So far, NGR participation has been very modest. PG&E carried out a research, development, and demonstration program supported by California's Electric Program Investment

46 Rothleder, 2017.

47 CAISO. (Undated). *Proxy Demand Resource (PDR) & Reliability Demand Response Resource (RDRR) Participation Overview* [Presentation]. Retrieved from http://www.caiso.com/documents/pdr_rdrrparticipationoverviewpresentation.pdf

48 CAISO, 2018 and CAISO. (2017). *2016 Annual Report on Markets Issues & Performance*. p 31. Retrieved from http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf

49 FERC, 2018.

50 FERC. (2016). *Order Accepting Proposed Tariff Revisions Subject to Condition*. Docket No. ER16-1085-000. Retrieved from https://www.ferc.gov/CalendarFiles/20160602164336-ER16-1085-000.pdf

Charge. Under the program, PG&E explored and evaluated participation in CAISO markets under the NGR model by two distribution network-connected sodium-sulfur battery energy storage facilities, the 2-MW Vaca-Dixon battery in Vacaville, CA and the 4-MW Yerba Buena battery in San Jose. These were the first battery storage facilities to participate in CAISO markets. According to PG&E's 2016 assessment report, the most advantageous revenue stream from CAISO for the facilities came from participation in the frequency regulation markets.[51] In contrast, the assessment found that participation in the day-ahead and real-time energy markets was not worthwhile because energy price differentials in these markets were not consistently large enough to support arbitrage. That is, the facilities could not regularly find large enough differentials to cover the costs of round-trip losses inherent in charging and discharging. This may have been partly attributable to location: if the facilities had been located at nodes where negative prices occurred more frequently, then the business case for energy market arbitrage may have been stronger. Given the dominance of revenues from frequency regulation services, PG&E surmised that it might have been more cost-effective — at least given location and market dynamics that were experienced during the study — to invest in shorter duration batteries, say, 30-minute instead of seven-hour duration batteries. Meanwhile, these facilities also provided value on the local distribution network. Other examples of NGR model utilization include a pilot program supported by the Department of Defense under which a plug-in EV fleet situated on the Los Angeles Air Force Base participates in CAISO markets while also providing peak shaving services on the base.[52]

Though NGR participation to date has been modest, as the needs of the grid evolve to integrate more renewables, the value of DER combinations that can provide ancillary services or be made to operate more like firm resources may increase.

None of the NGR examples to date involve aggregated combinations of PV with other DERs. CAISO is the first ISO to fully open the door to this kind of combination, and it may be that other ISOs will soon develop similar participation models. However, these innovations are happening at a time when most ISOs have historically low energy prices, reserve margins well above their targets (thus reducing the capacity value of all resources), and a modest need for ancillary services that is adequately filled by existing resources. As the needs of the grid evolve in response to greater deployments of variable generation resources (mostly utility scale wind and solar), the value of DER combinations that can provide ancillary services or be made to operate more like firm resources may increase, and these new participation models could become attractive to customers and aggregators.

B. Use Case 2: Installing DERs for Resilience

According to the National Oceanic and Atmospheric Administration, 2017 was the worst year the United States has ever seen for natural disasters. There were 16 weather-related events that caused more than a billion dollars in damages, and total damage from these major events exceeded $300 billion. The year 2018 was the fourth worst year, with 14 major events and total damage estimated at $96 billion.[53] Power outages were a huge factor in the damage caused by these major events,

51 Pacific Gas and Electric Company. (2016). *EPIC Final Report: EPIC Project 1.01 – Energy Storage End Uses: Energy Storage for Market Operations*. Retrieved from https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-1.01.pdf

52 U.S. Department of Defense Los Angeles Air Force Base. (2016, May 3). *Vehicle-to-Grid Pilot Overview* [Presentation before the CPUC/CAISO Joint Workshop on Multi-Use Applications]. Retrieved from (www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=11279) and Smith, J. (2017). *EV Charging Station and Los Angeles Air Force Base V2G Pilot Technical Evaluations* [Presentation]. Southern California Edison. Retrieved from https://www.energy.gov/sites/prod/files/2017/11/f46/16-fupwgfall2017_smith.pdf

53 National Oceanic and Atmospheric Administration. *Billion-Dollar Weather and Climate Disasters: Overview* [Webpage]. Retrieved from https://www.ncdc.noaa.gov/billions/

but even routine storms can cause lengthy and costly grid outages. Human-caused disasters are also a threat to the grid. A 2017 survey found that a quarter of utility executives in North America believed there was a significant likelihood that a cyber attack would take down part of the grid in the next five years.[54]

Concerns about extreme weather events and cyber security have sparked conversations across the country about the "resilience" of the power grid, with renewed urgency on finding solutions. Although there is no universally accepted definition of resilience, most definitions are similar to this one adopted by the National Infrastructure Advisory Council in 2009: "Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event."[55] At the federal level, conversations about resilience are being led by the U.S. Department of Energy and FERC. For example, in January 2018 FERC initiated a new proceeding to examine the resilience of the bulk power system.[56] FERC's aim is to develop a common understanding across the industry of what resilience of the bulk power system means and requires. FERC also wants to understand how the ISOs assess resilience so the Commission can decide whether further action is necessary.

DERs are increasingly viewed as realistic options for promoting grid resilience. The capabilities and the costs of PV, other DG technologies, and electricity storage are rapidly improving. In recent years, for the first time ever, we've seen the development of combinations of DG, electricity storage, and microgrids as supplements or alternatives to what was once the only realistic technology for riding through grid outages: diesel backup generation. Today, resilience is a major motivation for many entities who are investigating — and in some cases installing — DER combinations. For example:

- State and local governments are using DER combinations to simultaneously meet their resilience and sustainability goals. A few years ago, Salt Lake City, Utah, commissioned the first net zero energy public safety building in the United States. The building was designed to be super-efficient, and it has 380 kW of PV and backup diesel generators. Approximately 30% of the solar panels are wired to provide electricity to the building even if the grid goes down.[57] The city is also working with a healthcare facility to integrate PV and energy storage into its emergency management plans. Duluth, Minnesota has taken similar steps, adding 13 kW of PV and 6 kW/14.2 kWh of energy storage to the city-owned Hartley Nature Center. This building can function when the grid is down and is designed to serve as both a community shelter and an emergency base of operations for the city.[58] Smaller cities like Sterling, Massachusetts, are also demonstrating the resilience potential of DERs. Sterling's municipal electric utility deployed a 2-MW PV array and 2-MW/3.9-MWh battery storage microgrid that can provide up to 12 days of emergency backup power to the city's police station and dispatch center.[59]

- The U.S. Army views DER combinations as a smart supplement or alternative to diesel generators for energy resilience. Nearly 20 U.S. Army bases already have or are developing onsite renewable generation combined with energy storage or microgrid capabilities (Figure 3[60]). Resilient renewables projects are also being developed at many Air Force, Navy, Marine, and National Guard installations, in some cases at little or no incremental cost to taxpayers. All these installations of DER combinations are happening because of the military's need to continue operations and power critical infrastructure even when the grid goes down.

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54 Accenture Consulting. (2017). *Outsmarting Grid Security Threats*. Retrieved from https://www.accenture.com/t20170928T152847Z__w__/us-en/_acnmedia/PDF-62/Accenture-Outsmarting-Grid-Security-Threats-POV.pdf

55 National Infrastructure Advisory Council. (2009). *Critical Infrastructure Resilience Final Report and Recommendations*. Retrieved from https://www.dhs.gov/sites/default/files/publications/niac-critical-infrastructure-resilience-final-report-09-08-09-508.pdf

56 FERC Docket No. AD18-7-000.

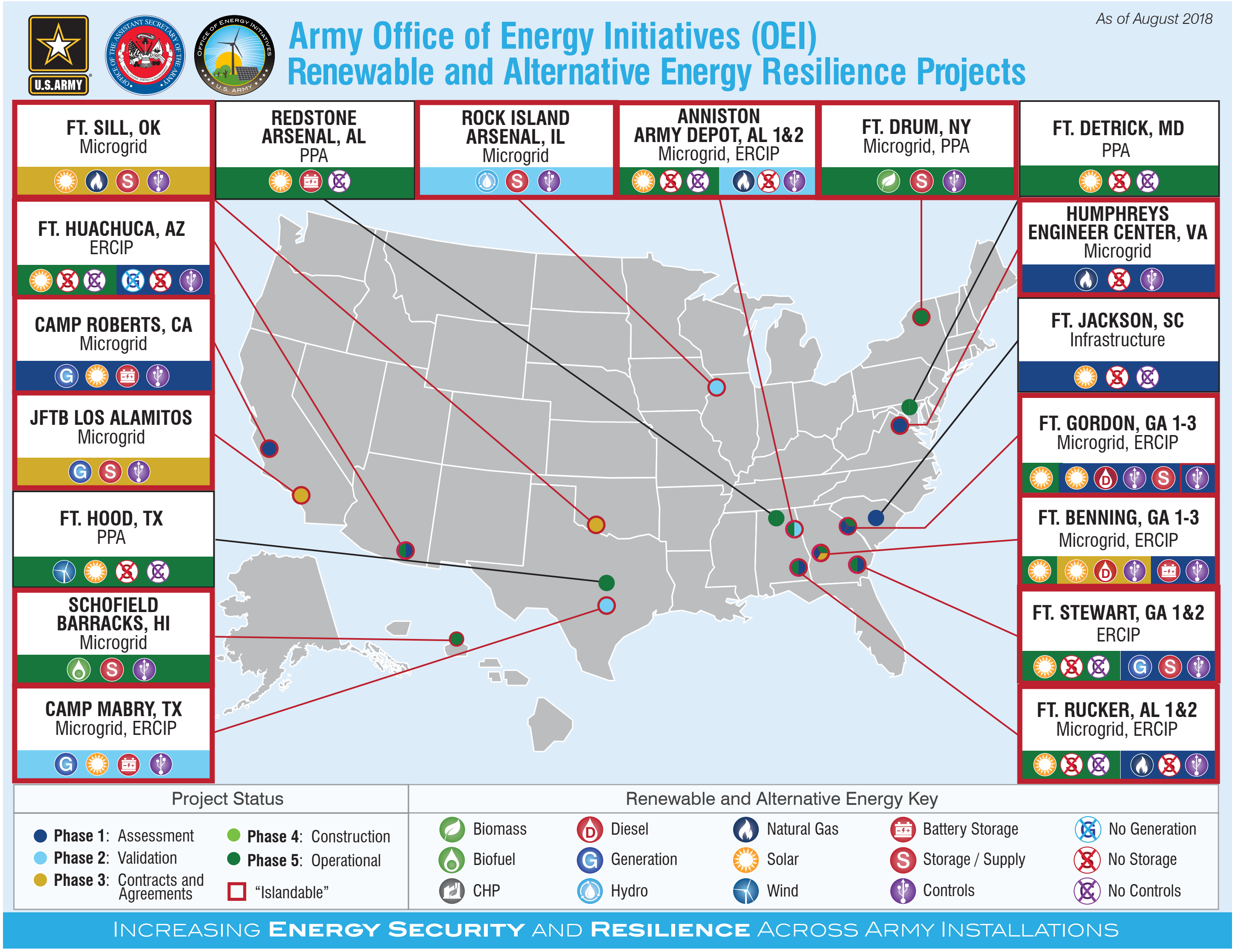
57 SLCGreen. (2014, June 25). City Celebrates a Trio of Landmark Solar Projects [Blog post]. SLC Green Blog. Retrieved from https://slcgreenblog.com/2014/06/25/city-celebrates-a-trio-of-landmark-solar-projects/

58 Galbraith, S. (2017). *Resilient Power Project Case Study: Hartley Nature Center*. Clean Energy Group. Retrieved from https://www.cleanegroup.org/wp-content/uploads/Hartley-Nature-Center-Case-Study.pdf

59 Galbraith, S., and Olinsky-Paul, T. (2018). *Resilient Power Project Case Study: Sterling Municipal Light Department*. Clean Energy Group. Retrieved from https://www.cleanegroup.org/wp-content/uploads/Sterling-case-study.pdf

60 Army Office of Energy Initiatives. (2018). *Renewable and Alternative Energy Resilience Projects*. Retrieved from http://www.asaie.army.mil/Public/ES/oei/projects.html

Figure 3. U.S. Army Energy Resilience Projects



Source: Army Office of Energy Initiatives. (2018). Renewable and Alternative Energy Resilience Projects.

The examples of this use case to date (not limited to the few cited above) have revealed several important opportunities and limitations to using DERs for resilience.

First, and most important, a grid-connected PV system will go down when the grid goes down unless it is islandable. Even if it is islandable, a PV system without energy storage can only power critical loads during daylight hours and only intermittently. If properly sized for local insolation conditions, an islandable PV system might fully meet the power needs of critical loads on a cloudless day, but without storage it would be unable to serve those same loads at night or when clouds pass overhead. Adding microgrid capability and possibly energy storage to a PV installation adds substantially to the costs. Those costs are typically found to be prohibitive, but a 2018 NREL study demonstrated for several types of commercial customers that "even though a PV and storage system might not appear to be economical under traditional cost-benefit calculations, placing a value on the losses incurred from grid disruptions can make a PV and storage system a fiscally sound investment."[61]

61 Army Office of Energy Initiatives, 2018

Second, energy efficiency is a crucial but often overlooked component of energy resilience. In many of the examples to date, project developers have found it is extremely challenging and costly to build a DER microgrid that has enough power and storage to survive prolonged (multiday) grid outages. The key to extending that capability as long as possible is making critical loads as efficient as possible. Energy efficiency measures also allow the DER owner to maximize other participant, utility, and societal value streams when the grid is functioning normally.

Third, even if a combination of DERs is built for the primary purpose of boosting energy resilience, the resources will operate when the grid is functioning normally and can provide secondary benefits such as participant bill savings (e.g., through reducing peak demand and demand charges) or utility system benefits (e.g., fast ramping service). However, it may be necessary for the owner of the DER microgrid to forego some of this potential value to ensure that the system will have sufficient stored energy to serve critical loads should an emergency arise. Diesel backup generators, in contrast, almost never operate when the grid is functioning normally.

C. Use Case 3: Installing DERs as an NWA to Utility Infrastructure

Avoiding the cost of investing in generation, transmission, or distribution physical plant can be an important source of utility system value for local energy resources, but combinations of local energy resources are usually required to address the need. The lesson that combinations of resources are necessary is not a new one. Thirty years ago, the Bonneville Power Administration (BPA) began using improved consumption and system data to study how local energy efficiency, DR, and DG resources in the Pacific Northwest region could be combined to address local reliability concerns. Perhaps the first successful use of NWAs[62] to successfully defer the need for an expensive transmission project was executed by BPA and Orcas Energy Partners in 1993 when a BPA cable to the San Juan Islands failed. BPA Transmission, BPA Power, and Orcas Power and Light Cooperative worked together to manage limited transfer capability on the cable with a combination of DR and DG resources. Both resources were necessary to forge a cost-effective solution because capacity limits and voltage support were both required. Together the local resources addressed capacity limits and voltage support needs and deferred the need for a replacement cable for five years.[63]

More recent NWAs to high-voltage transmission proposals affirm the need to combine resources to obviate, reduce, or defer the need for expensive physical infrastructure investment. The Brooklyn-Queens Demand Management (BQDM) project is an NWA that was precipitated by the projected need for a $1.2 billion substation upgrade to address local load growth. Like the BPA project, the BQDM project required a combination of resources to meet the reliability need. In the case of BQDM, a long duration (noon to midnight) peak demand indicated a need for local solar to address daytime demand, with lighting energy efficiency programs, DR, and storage contributing to addressing peak demand after sunset.[64] Regulators ultimately approved a $200 million operating budget proposal by the local utility, Consolidated Edison, and a plan to procure 52 MW of demand reduction from nontraditional customer-side and utility-side solutions (i.e., DERs) by the summer of 2018. In a January 2019 update submitted to regulators, the utility reported that those DER procurement goals were achieved through a combination of energy efficiency, DR, energy storage, and DG resources, and the program remained under its approved operating budget.[65]

Similarly, the Oakland Clean Energy Initiative (OCEI) is combining local resources to enable the retirement of an uneconomic power plant without having to build a 115-kV or 230-kV transmission upgrade. Pacific Gas and Electric Company

62 The term "non-wires solution" is generally considered synonymous to "non-wires alternative" and is the preferred term in some jurisdictions, including New York, which is cited as one of the examples herein. At the time of publication of this report, "alternatives" appears to be the more commonly used term and thus it is used throughout this report. Some materials on this subject may distinguish between alternatives as options that are considered and solutions as options that are implemented.

63 Brown, F. (2018, June). *BPA and Non-wires Work: Some Highlights from the Last 30 Years* [Presentation before PNDRP]. BPA.

64 Walton, R. (2017, July 19). Straight Outta BQDM: Consolidated Edison looks to expand its non-wires approach. *Utility Dive*. Retrieved from https://www.utilitydive.com/news/straight-outta-bqdm-consolidated-edison-looks-to-expand-its-non-wires-appr/447433/

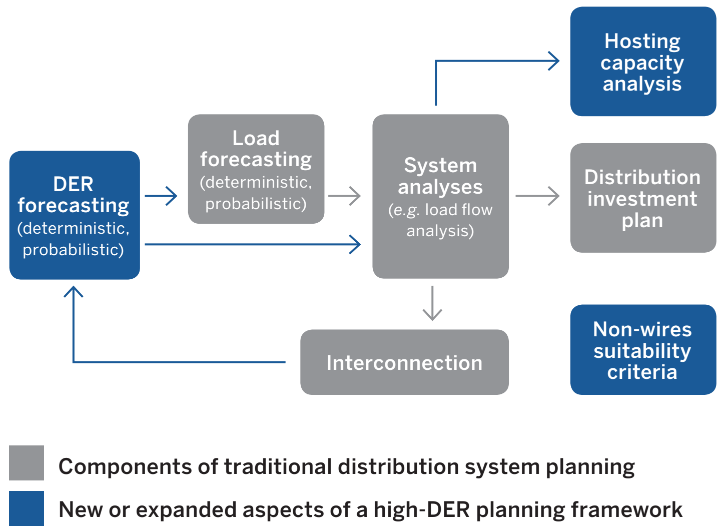
65 Reilly, G. (2019). *Brooklyn Queens Demand Management Program Implementation and Outreach Plan*. Consolidated Edison Company of New York, Inc. Retrieved from http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={CF3203B7-0F82-4CA9-8D79-90968F6D5D9F}

and East Bay Community Energy proposed to procure 25 to 40 MW of energy efficiency, DR, and distributed PV where at least 19 MW needs to be load-reducing DR, and 10 MW/40 MWh of storage. Substation upgrades and line re-ratings are also part of the package, but high-voltage transmission additions are not. This combination of resources is expected to ensure local reliability at a cost that is at least $250 million less than the cost of transmission upgrades or continued operation of the power plant.[66] The project sponsors issued a Request for Offers in April 2018 and expect to submit negotiated agreements to the CPUC in March 2019 for regulatory approval.[67]

The projects discussed so far were driven by "traditional" sources of reliability concern: loss of an important transmission line, rapid local load growth, or retirement of a local generation facility. The non-wires opportunities for DERs in the future are increasingly caused by DER growth itself. Concentrated development of distributed solar and EV charging are two likely drivers of future non-wires opportunities, and, unlike the projects to date that have been designed to defer or avoid transmission system investment, these NWAs are likely to defer or obviate the need for distribution system investment. One possible venue for considering these NWAs on the distribution system is an integrated distribution planning (IDP) proceeding, and in California and Hawaii explicit consideration of non-wires options has begun.[68]

With the success of the BQDM project, New York's Reforming the Energy Vision process embraced systematic changes that incorporate evaluation of NWAs. The Joint Utilities Supplemental Distribution Planning Report in New York in 2016[69] includes NWAs explicitly in an innovative process to identify and plan for impending distribution system reliability issues. The planning report calls out DER forecasting, hosting capacity analysis, and non-wires suitability criteria as three new functions that need to be included in an evolving distribution planning process to proactively address distribution-based reliability concerns (Figure 4).

Figure 4. Evolving Distribution Planning Process



Source: Joint Utilities. (2016). Supplemental Distributed System Implementation Plan.

The number of NWA projects is growing rapidly, and researchers are beginning to compile examples.[70] A few more recent examples of non-wires investment on the distribution system include:

- the SDG&E Borrego Springs Project,[71] where a utility-owned microgrid powered by local solar, storage, and back-up diesel generation enables islanding of an entire substation area that is served by a single transmission line as an alternative to building additional transmission capacity to serve the area;

66 Roselund, C. (2018, March 29). CAISO approves clean energy, storage and system upgrades to replace peaker plant. *PV Magazine*. Retrieved from https://pv-magazine-usa.com/2018/03/29/caiso-approves-clean-energy-storage-and-system-upgrades-to-replace-gas-plant/

67 Details about the Request for Offers can be found at https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/2018-oakland-clean-energy-initiative-rfo.page?ctx=large-business

68 See: Volkmann, C. (2018). *Integrated Distribution Planning: A Path Forward*. GridLab. Retrieved from https://gridlab.org/s/IDP-Whitepaper_GridLab.pdf, and Cooke, A., Schwartz, L., and Homer, J. (May 2018). *Distribution System Planning – State Examples by Topic*. PNNL-27366. Retrieved from https://epe.pnnl.gov/pdfs/DSP_State_Examples-PNNL-27366.pdf

69 Joint Utilities. (2016). *Supplemental Distributed System Implementation Plan*. NY PSC Case 16-M-0411. Retrieved from http://jointutilitiesofny.org/wp-content/uploads/2016/10/3A80BFC9-CBD4-4DFD-AE62-831271013816.pdf

70 For a compilation of examples, see: Dyson, M., Prince, J., Shwisberg, L., and Waller, J. (2018). *The Non-Wires Solutions Implementation Playbook*. Rocky Mountain Institute. Retrieved from https://www.rmi.org/insight/non-wires-solutions-playbook/, and Chew, B., Myers, E., Adolf, T., and Thomas, E. (2018). *Non-Wires Alternatives: Case Studies from Leading U.S. Projects*. Smart Electric Power Alliance, Peak Load Management Alliance, and E4TheFuture. Retrieved from https://e4thefuture.org/wp-content/uploads/2018/11/2018-Non-Wires-Alternatives-Report_FINAL.pdf

71 LBNL. *Borrego Springs* [Webpage]. Retrieved from https://building-microgrid.lbl.gov/borrego-springs

- the National Grid Tiverton Substation Project,[72] which defers the need for a substation feeder upgrade with a combination of energy efficiency and DR programs; and
- Central Maine Power's Boothbay project,[73] where 1.6 MW of energy efficiency, DR, PV, and storage are obviating the need for a transmission upgrade.

In each case, the combination of DERs offers the local energy, capacity, and voltage support required to address critical needs at the time and in the place required. Because utilities often procure these NWAs from participants or solution providers who install DERs, the utility system value streams generally flow through to the participant or solution provider, offering fair compensation for value and increasing the likelihood that DERs get installed when and where they are cost-effective.

D. Use Case 4: Using DERs to Address Environmental Challenges

One additional use case that is worthy of further investigation is the potential to use coordinated and targeted DER deployments to improve air quality, reduce air pollution-related health costs, and satisfy federal Clean Air Act requirements at a lower cost than traditional pollution control measures. Discussions about this use case have been largely hypothetical to date, but the potential environmental benefits of DER combinations are indisputable.

Energy efficiency and PV clearly reduce the need for utility-scale generation of electricity, which usually results in reduced operation of and emissions from fossil-fueled generators.[74] EVs increase demand for electricity and may increase fossil-fueled generator output and emissions unless fueled by renewables, but those increases tend to be more than offset by decreases in tailpipe emissions from gasoline or diesel fuel combustion.[75] DR resources reduce demand and thus reduce emissions at the time they are operated, but if the customer later makes up for foregone energy consumption (e.g., they reduce output at one time but increase output later to make up for lost productivity) the net effect on emissions could be positive or negative. Energy storage resources can potentially increase or decrease emissions too, depending on when they charge and discharge.[76] Combining DR or energy storage with energy efficiency or PV can ensure that the air quality impacts are positive.

Given that energy efficiency and PV are currently the most commonly deployed DERs, the total effect of DERs on emissions and air quality is clearly positive today. All members of society share these environmental benefits. In some cases, DER owners are receiving partial compensation for those societal benefits; rarely do they receive full value for their contributions to air quality and public health. The potential to proactively pursue environmental benefits and appropriate compensation for customers through a DER environmental use case has yet to be fully explored, although some states have included the impact of DERs to a very limited extent in their air quality improvement plans.[77]

72 National Grid. (2015). *2016 System Reliability Procurement Report*. RI PUC Docket No. 4581. Retrieved from http://www.ripuc.org/eventsactions/docket/4581-NGrid-2016-SRP(10-14-15).pdf

73 GridSolar, LLC. (2016). Final Report: Boothbay Sub-region Smart Grid Reliability Pilot Project. Docket No. 2011-138. Retrieved from http://www.neep.org/sites/default/files/resources/FINAL_Boothbay%20Pilot%20Report_20160119.pdf

74 A study for ISO New England, for example, found that fossil-fueled generators were operating on the margin at least 70% of the time in each month of 2016. This means that reductions in demand for grid-supplied electricity affected fossil-fueled generators more than 70% of the time. See: ISO New England. (2018). *2016 ISO New England Electric Generator Air Emissions Report*. Retrieved from https://www.iso-ne.com/static-assets/documents/2018/01/2016_emissions_report.pdf

75 Nealer et al., 2015.

76 Storage devices have round-trip losses, meaning that they are net consumers of electricity. The net effect on emissions will depend not only on round-trip losses, but also on the differential between the emissions rate of the resources used to charge the device and the emissions rate of the marginal resource that would have been dispatched at the time the resource is discharged, had it not been available.

77 For example, the U.S. Environmental Protection Agency noted in a 2012 document several examples of where the impacts of energy efficiency measures had been included in an approved air quality improvement plan. See: U.S. Environmental Protection Agency. (2012). Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans - Appendix K: State, Tribal and Local Examples and Opportunities. Publication No. EPA-456/D-12-001l. Retrieved from https://www.epa.gov/sites/production/files/2016-05/documents/appendixk_0.pdf. It should be noted that these examples differ from an "environmental use case for DERs" in that all the examples stem from jurisdictions that sought credit for the environmental impact of energy efficiency policies that had been adopted primarily for non-environmental reasons.

VI. A Path Toward Capturing More Value from DER Combinations

Section IV explained the main mechanisms for capturing value, and Section V provided real-world "use cases" for DER combinations and a summary of some of the values that currently are and are not being captured. In this section, we aim to chart a path forward for capturing more of the potential value.

Capturing the full value of DER combinations is an ambitious, perhaps only aspirational, goal. It would require action on many issues, at many levels, by many different decision-makers: federal and state regulators, utilities, market operators, and DER service providers to name the most obvious. The challenge is all the more difficult because we can't say with certainty today what the optimum solutions are to all relevant challenges. The broad outlines of solutions are apparent, but the details remain vague and untested on some issues.

Fortunately progress toward the aspirational goal of full value can be made incrementally through the independent actions of diverse decision-makers. All the actions necessary to capture full value do not need to happen at once, if ever. In some cases, incremental improvements can increase the value proposition enough to turn a DER project from a negative value proposition to a positive one. On some issues, experimentation and testing will be necessary, and on most matters, solutions will have to adapt to changing market and technology realities over time.

With those caveats in mind, the remainder of this paper focuses on charting a path forward for policymakers, utilities, ISOs, and other power sector stakeholders. It identifies specific actions that can be taken to address the challenges and move in a positive direction toward capturing more value from DER combinations. The actions fall into five broad categories.

- Technology, metering, communications, and data systems;
- Smart retail rate design (tariffs);
- Markets;
- Planning; and
- Utility procurement.

A. Technology, Metering, Communications, and Data Systems

Before we consider the actions that can lead to compensation commensurate with the value of DER combinations, we must first examine the policy and regulatory aspects of some crucial technologic improvements that can increase the ability of DERs to provide value, and then consider a suite of actions relating to metering, communications, and data systems that can enable DER owners, utilities, and ISOs to securely exchange information that accurately reveals value and enables responses that capture value.

The technologies behind PV, energy storage, and EVs are all improving at a rapid pace. For example, PV panels are getting more and more efficient at converting sunlight into electricity,[78] while batteries are capable of moving EVs farther and farther on a single charge.[79] These trends are likely to continue, but this report is not focused on those kinds of technology innovations. Instead we are focused on technology-related actions that policymakers and regulators must take to translate DER technology improvements into value.

The first technology-related development to consider is the emergence of smart inverters for inverter-based DERs (including PV, distributed wind, and some forms of energy storage). Unlike older inverter technologies, today's smart inverters can enable DERs to provide ancillary services and to maximize energy value by riding through some grid disturbances. However, those results will not happen automatically without steps to leverage the capabilities of smart inverters. Two of these steps are described here, followed by some general recommendations relating to metering, communications, and data.

1. Updating Interconnection Standards

Most state PUCs and utilities will need to update the standards and procedures they use to approve the interconnection of DERs to the grid. The federal Energy Policy

78 U.S. Department of Energy. *Research Cell Efficiency Records* [Webpage]. Retrieved from https://www.energy.gov/eere/solar/downloads/research-cell-efficiency-records

79 McDonald, L. (2018, October 27). US Electric Car Range Will Average 275 Miles By 2022, 400 Miles By 2028 — New Research (Part 1). *CleanTechnica*. Retrieved from https://cleantechnica.com/2018/10/27/us-electric-car-range-will-average-275-miles-by-2022-400-miles-by-2028-new-research-part-1/

Act of 2005 requires electric utilities to provide interconnection services "based on standards developed by the Institute of Electrical and Electronics Engineers ... as they may be amended from time to time." Many state PUCs have promulgated administrative rules to codify this requirement. In some cases, state rules incorporate the Institute of Electrical and Electronics Engineers (IEEE) interconnection standard by reference, so when the standard is updated the rules do not have to be updated. But in other states incorporation by reference is not allowed and the rules must be updated each time the standard is updated. This is relevant because IEEE published a comprehensive update in 2018, *IEEE 1547-2018 - IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*.[80] This updated interconnection standard is significantly better for DERs than the previous version of the standard. For example, whereas the old standard required DG to trip off (cease operating) in the event of a transient frequency excursion on the grid, the new standard requires DG to ride through (remain operating) some of the more common excursions. State PUCs interested in capturing the benefits of the new standard will want to become engaged as utilities implement it. The new standard clarifies storage interconnection and offers the opportunity to consider expedited interconnection processes. In addition, the standard addresses important technical improvements that increase the value of DERs to the distribution utility and to the customers who adopt them. For example, the previous version of the standard required inverter-based DERs to automatically disconnect if they sense abnormal voltage or frequency on the grid. If there was a grid disturbance, this could potentially exacerbate the problem because DERs across the system would all trip off at the same time. Under the new standard, inverter-based DERs must be capable of riding through temporary small excursions from design voltage and frequency levels. This is good for the DER owners and helps system operators to better manage minor, temporary power quality problems. **Adopting the new interconnection standard as quickly as is practicable will increase the ability of DERs to provide value —** a separate question from capturing that value.

2. Activating Inverter Capabilities

To enable DERs to capture more of their full value, state PUCs and utilities will also need to require implementation of some of the optional features that are included in the Underwriters Laboratories *UL 1741 - Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources – Supplement A*.[81] To obtain UL 1741 SA certification, inverters must have certain inherent capabilities, but it is possible to interconnect an inverter that doesn't have the optional capabilities in Supplement A or one that has those optional capabilities deactivated. **In other words, UL 1741-compliant inverters may be capable of providing grid services, but that capability won't necessarily be activated unless PUCs and utilities require it.** California and Hawaii are two states that have already taken this step.[82]

3. Metering, Communications, and Data

In addition to DER capabilities, there are many prerequisite steps relating to metering, communications, and data systems that are necessary for enabling some of the value streams to be revealed and compensated. Utility system costs vary from second to second, day to day, season to season, and year to year. They also vary by location. This means that the utility system costs that can be avoided through a DER deployment also vary by time and location. To make sound decisions about whether to invest in DERs and how to operate them, customers need detailed information about utility system costs. Utilities and ISOs, in turn, need visibility about the existence, state, and capabilities of DERs installed on their systems and the means of communicating system costs to those customers in real time.

80 Despite their widespread use for public purposes, IEEE standards are proprietary. Information about purchasing the new IEEE 1547-2018 standard is available at https://standards.ieee.org/standard/1547-2018.html

81 UL 1741 is the standard that is used by manufacturers to demonstrate that inverters and other equipment comply with IEEE 1547 requirements. The current version of UL 1741 was published prior to the 2018 update of IEEE 1547, but "Supplement A" (UL 1741 SA) included *optional* features that went beyond what IEEE 1547 required at the time, to enable certified devices to adapt their behavior to stabilize the grid during abnormal operation rather than simply disconnecting. UL 1741 SA anticipated many of the updates to IEEE 1547, but is currently being updated to fully conform with the final version of IEEE 1547-2018 with the revised UL 1741 expected in 2020. The UL 1741 standard is also proprietary. Information is available at https://standardscatalog.ul.com/standards/en/standard_1741_2

82 Refer to CPUC Rule 21 (http://www.cpuc.ca.gov/Rule21/) and Hawaiian Electric Company Rule 14H (https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/14.pdf).

And to get compensation right, utilities and ISOs need to be able to measure the values that DER customers provide to the grid. The steps that require attention include the following.

- Utilities need to **deploy AMI** (i.e., smart meters and the systems for reading them). Digital smart meters are capable of measuring and recording power flows in either direction in small time increments, and they can electronically communicate data in real time. These capabilities are essential if the rate design reforms described later in this report are to be implemented. According to the U.S. Energy Information Administration, almost 79 million advanced meters had been installed in the United States by the end of 2017, representing 52% of all meters.[83] Where AMI has not yet been installed, it is entirely feasible to require DER owners to have smart meters without requiring all customers to do so. Aggregators may require AMI for the customers they serve.

- State PUCs should **initiate a "grid modernization" proceeding** to stimulate the necessary actions by utilities to implement not just smart meters, but also smart grid technologies on the distribution system and digital communications infrastructure to support these systems.[84] Real-time, high-speed, two-way digital communications between DER operators and system operators are essential to capturing the value of DERs. This applies certainly to the utility that operates the distribution system, but also to an ISO. As aggregated DERs begin offering services to both the distribution system operator, perhaps to address voltage issues, and to the ISO, perhaps offering fast frequency response, digital communication will be key to ensuring performance and ensuring appropriate compensation for services delivered. Smart meters are only part of the solution. System operators may need the ability to remotely control DERs (e.g., direct load control of air conditioners to shed load, or use of distributed battery energy storage systems to regulate voltage). Alternatively, a system operator can communicate system needs to customers or aggregators without having control of the DERs. But either of these options will only work efficiently if a strong digital communications backbone exists. Several states have enacted legislation requiring a grid modernization proceeding, and several state PUCs have opened such a proceeding on their own initiative. A 2018 report from the Pacific Northwest National Laboratory cites examples of successful grid modernization efforts from Massachusetts, Ohio, California, and Hawaii.[85]

- System operators will need to **upgrade information systems to handle huge amounts of data concerning two-way DER transactions,** recording when DERs consume or provide energy services and managing any associated financial settlements. ISOs already have the necessary systems in place, but control area operators and distribution utilities may not. Utilities and other LSEs may also need to update their billing systems if they move toward time-varying rates or rates that involve bidirectional charges and credits for DERs.[86]

- **Policies and procedures for data sharing need to be established to protect the privacy of DER customers while enabling them to engage aggregators, use smart phone applications, and otherwise pursue DER value opportunities.** A good starting point is to reinforce the principle that customers should own the data that utilities collect from them. Utilities should then make it as easy as possible for customers to share their data with third parties, consistent with protecting both the customer's privacy and the utility information system's security. Open source data platforms offer the best way to tap this potential in an economically efficient manner. The U.S. Department of Energy (US DOE) kicked off a "Green Button" initiative in 2012 to fill this need. Green Button is a voluntary, industry-led effort that enables customers of

83 U.S. Energy Information Administration. (2018). Form EIA-861 Data Files for 2017 [Database]. Retrieved from https://www.eia.gov/electricity/data/eia861/. Note that EIA defines AMI to include not only real-time meters with built-in two-way communications capabilities but also basic hourly interval meters that might not have all the capability necessary for capturing some DER value streams.

84 "Grid modernization" is a catch-all term that encompasses different topics in each jurisdiction. In addition to smart meters, smart grid, and digital communications infrastructure, some states will use this type of proceeding to address distribution system planning, DER interconnection and integration, utility business models, and so on. The scope can be tailored to the needs of each jurisdiction.

85 Cooke et al., 2018.

86 Some observers have suggested that provision of voltage support or other ancillary services could conceivably be made a requirement for interconnection approval, rather than a compensated service. This would ensure the utility can obtain these values from DERs, but DER deployment will be suboptimal if customers are not compensated for these services.

participating utilities to download their own data from the utility's website with a simple click on a green button. The data are downloaded in a standard open source format, enabling the customer to then upload that data to the websites or applications of third-party energy service companies that have built services based on the green button data standard. Or, in some cases, a new capability called "Green Button Connect" enables the customer to transfer their data from the utility directly to a third party in a single step. According to US DOE, over 50 utilities serving more than 60 million customers now provide a green button on their websites.[87] Many software developers have created applications that use green button data, for example to estimate the savings a customer might expect if they install PV.

- Even as DER combination opportunities grow, the risk for cybersecurity breaches threatens to slow the momentum. Utilities and regulators across the country (and the world) have taken an acute interest in cybersecurity in recent years, especially after a cyber-attack in Ukraine in December 2015 left more than 200,000 customers without power. Cybersecurity will become increasingly important as the reliable and efficient operation of the grid becomes more and more dependent on DG, flexible loads, transactive markets, and digital communications between system operators and millions of DERs. There are no "solutions" to this cybersecurity challenge — new threats will continually arise that must be anticipated and if possible prevented. But **utilities and regulators can and should take proactive steps to meet the challenge. FERC has the responsibility and authority to establish and enforce minimum cybersecurity standards for the bulk power system, whereas states are responsible for regulating distribution systems.** Some states have already acted. For example, New Jersey requires utilities to identify and mitigate cyber risks, report incidents and suspicious activity, create incident response and recovery plans, and provide training programs. In Texas, the PUC conducts annual cybersecurity audits.[88]

- The Energy Independence and Security Act of 2007 assigned responsibility to FERC to adopt standards and protocols to ensure smart grid interoperability. This law gave NIST responsibility to coordinate development of a framework and roadmap for achieving interoperability.[89] NIST created a Smart Grid Interoperability Panel of industry experts to solicit input for the framework, which later spun off into a non-profit, public–private partnership organization. The interoperability of grid-connected devices is essential for cybersecurity; efficient deployment, upgrades, and maintenance activities; and the development of new technologies and applications that can "plug in" to the existing system. **There are inherent tradeoffs between enforcing standards and encouraging innovation, so it will be necessary for policymakers at FERC and NIST and in states to continue focusing on interoperability for many years and to ensure that utilities abide by adopted standards and protocols.**

- ISOs need to work with utilities and other LSEs to **ensure that if a DER (or combination of DERs) is to be used for both bulk power and distribution system services, the DER's capabilities are transparently registered.** A registry system can ensure that DERs will not be expected to provide simultaneously incompatible services and that double payment by the ISO, utility, LSE, or third-party aggregator is precluded.[90]

- DER customers, technology companies, aggregators, or utilities must **develop optimization algorithms and system controls for managing DER combinations and fleets of aggregated DERs.** Using a DER for one purpose may preclude its use for a different purpose. Compensation may be available to the customer through bill reduction in a wholesale electricity market or (someday) in a distribution system market. To get as much value as possible, somebody must decide when and how to operate DERs (especially storage, DR, and EVs) to maximize

87 US DOE. *Green Button* [Webpage]. Retrieved from https://www.energy.gov/data/green-button

88 https://www.forbes.com/sites/constancedouris/2018/01/16/as-cyber-threats-to-the-electric-grid-rise-utilities-regulators-seek-solutions/#2d8adbaa343e

89 Pub. L. 110-140. Retrieved from https://www.govinfo.gov/content/pkg/PLAW-110publ140/html/PLAW-110publ140.htm

90 For example, a storage resource might hypothetically be asked by the distribution utility to absorb energy to protect local power quality at the same time that the ISO wants the resource to discharge energy to address a system peak. Those services would be incompatible, and if the resource is obligated by contract to provide both services it could create problems. There are also concerns, raised in the proceeding that resulted in FERC Order 841, that storage resources could reap windfall profits if they receive wholesale market compensation for services as well as bundled cost-of-service rates through utility ownership or a third-party PPA with a utility. Similar concerns may be raised for DERs that receive compensation based on utility avoided costs, but also receive market compensation.

value, or somebody must develop an "intelligent agent" — a form of artificial intelligence — that can autonomously and automatically make those decisions. Today a limited set of case studies are available for examining how utilities, aggregators, or customers have operated DERs to maximize value. As more and more DERs are deployed and more and more value streams become possible, research and best practices for addressing this emerging challenge will be much needed.

Table 4 summarizes all the recommended steps with respect to technology, metering, communications, and data systems and the parties most likely to be involved in each step.

Table 4. Summary of Recommendations: Technology, Metering, Communications, and Data Systems

	DER Owners	DER Aggregators	Utilities/ LSEs	State Utility Regulators	ISOs/System Operators	FERC/Other Federal Agencies
Adopt IEEE 1547-2018 standard			✔	✔		
Require activation of smart inverter features that enable provision of grid services			✔	✔		
Deploy AMI (for DER owners, if not for everyone)	✔	✔	✔	✔		
Initiate a "grid modernization" proceeding			✔	✔		
Upgrade information systems to handle two-way DER transactions			✔		✔	
Establish data-sharing procedures and protections		✔	✔	✔		✔
Develop and enforce cybersecurity standards			✔	✔	✔	✔
Implement and enforce NIST smart grid interoperability standards and protocols				✔	✔	✔
Register the capabilities of DERs in a centralized system	✔	✔	✔		✔	
Develop optimization algorithms/system controls for managing DER fleets	✔	✔	✔			

B. Smart Retail Rate Design (Tariffs)

Because system costs and potential avoided costs are time- and location-dependent, appropriate compensation of DERs is best managed through retail electricity rates that vary by time and location. A 2017 study by NREL assessed the potential overall bill savings for residential customers who combine PV with DR options (a controllable smart water heater or smart air conditioning unit) or battery storage under various retail rate designs. The authors concluded that, "solar plus [DR or battery storage] generally has a greater impact on system value under TOU and demand charge rate structures."[91] Again, *much* of the value of DER combinations can be captured with retail rate designs that don't vary by time or location, but more sophisticated rate designs will better reveal and compensate for their true value. Price signals for the services that DERs can provide will be muted without a time-dependent element, in particular.

The Regulatory Assistance Project (RAP) offers advice on "smart rate design" in two companion publications, one for residential customers and one for non-residential customers.[92] Both publications were written with an eye toward designing retail rates that can be applied equally to customers with and without DERs, and within or outside of wholesale electricity markets. The rate designs recommended by RAP were crafted to recognize and at least partially compensate customers for the utility system value of DERs and combinations of DERs while adhering to traditional rate design principles (e.g., ensuring utility cost recovery, avoiding subsidies across customer classes, keeping rates understandable for customers, and so on).

RAP recommends that retail rate designs adopted by utilities, other LSEs, and state PUCs include the following key attributes.

1. **Customer charges.** A small, non-bypassable monthly customer charge can be a just and reasonable element of retail rate design for all customer classes, but **customer charges should be designed only to recover costs that vary with the number of customers served** by the utility, such as metering, billing, and collection costs. If it is necessary for the utility to install extra meters to record the consumption or production of DERs or to develop special software to correctly calculate bills for customers who have DERs, then it may be appropriate for those customers to pay a higher customer charge than other customers in the same class who do not have DERs. But if such costs are not necessary, the customer charges should be the same.

2. **Demand charges.** It can also be just and reasonable to assess each customer a demand charge that recovers the portion of the power system that is sized based on that customer's maximum demand, regardless of whether it coincides with systemwide peak demand (i.e., a non-coincident peak demand charge). **For nearly all residential customers, this demand charge should only recover the costs of the final line transformer and service drop** to the residence because those are the only system components sized to meet the individual customer's peak demand. **For some non-residential customers, there may be additional dedicated distribution system facilities that are sized to meet a single customer's peak demand, and any such site infrastructure costs should be recovered in a demand charge along with the final line transformer and service drop costs.** With this rate design, customers who have combinations of DERs could potentially reduce their demand charges, but only if they reduce their demand in ways that allow the utility to downsize the distribution system assets that are dedicated to those customers. Either way, the rate design will ensure that every customer contributes toward the recovery of all distribution system costs dedicated specifically to serving their load.

3. **Energy charges.** All other utility costs are best recovered through energy charges that align customer costs (and thus, decisions about energy usage) with long-term system cost drivers. The rationale for this highly debated point is fully explained in RAP's rate design publications.

91 O'Shaughnessy, E., Ardani, K., Cutler, D., and Margolis, R. (2017). *Solar Plus: A Holistic Approach to Distributed Solar PV*. National Renewable Energy Laboratory. Quotation at p 36. Retrieved from https://www.nrel.gov/solar/solar-plus-holistic-approach.html

92 Lazar, J., and Gonzalez, W. (2013). *Smart Rate Design for a Smart Future*. The Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/. Linvill, C., Lazar, J., Dupuy, M., Shipley, J., and Brutkoski, D. (2017). *Smart Non-Residential Rate Design*. The Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/smart-non-residential-rate-design/

a. For residential customers, **using a relatively simple TOU rate design** that provides separate prices for consumption during off-peak, mid-peak, on-peak, and critical peak time periods can address the time-varying nature of system cost drivers without introducing unnecessary complexity. PTRs offer an alternative to critical peak prices. Another option is to add a super-off-peak rate to encourage better use of the existing system capacity for EV charging and other flexible loads. Peak rates should reflect not only the costs of generating and delivering power during system peaks, but also the value of avoiding future capacity additions.

b. **For non-residential customers, more complex time-varying rates can be used, potentially including real-time pricing,** which is the most complex option but also the one that sends the most accurate price signals.

c. Because system costs also depend on the location of energy consumption, a nodal or locational element may also be necessary to send accurate price signals. Regulators have generally concluded that it is unwise (or politically untenable) to charge differing rates to residential customers of a single utility based on each customer's location, so nodal pricing might not be workable for residential customers. **Nodal pricing may be acceptable and should be considered for non-residential customers.**

4. **Bi-directional charges.** To balance the need for simple, understandable rates with the desire to accurately reflect utility system avoided costs, **customers who are capable of injecting excess energy into the grid from a DER should be compensated at the same time-varying energy rates that they would pay for energy consumption.** Billing determinants for demand charges should be based on the higher of their maximum export of power and their maximum consumption of power, as the maximum flow of power in either direction dictates the size (and thus the costs) of site infrastructure. The use of bi-directional charges can be particularly effective for combinations of DERs, because it ensures that customers are billed or credited an appropriate amount based on their net energy consumption, regardless of how each individual DER is operating.

Illustrative examples of (hypothetical) residential and non-residential rate designs based on these RAP recommendations are presented in Tables 5 and 6.

Table 5. Illustrative Residential Rate Design

Rate Element	Based on the Cost Of	Illustrative Rate
Customer charge	Service drop, billing and collection only	$4.00/month
Transformer charge	Final line transformer	$1/kVA/month
Off-peak energy	Baseload resources + transmission and distribution	$.07/kWh
Mid-peak energy	Baseload + intermediate resources + T&D	$.09/kWh
On-peak energy	Baseload, intermediate, and peaking resources + T&D	$.14/kWh
Critical peak energy (or PTR)	Demand response resources	$.74/kWh

Source: Lazar and Gonzalez. (2013). *Smart Rate Design for a Smart Future*.

Table 6. Illustrative Non-Residential Rate Design

	Production	Transmission	Distribution	Total	Unit
Metering, billing			$100.00	$100.00	Month
Site infrastructure			$2/kW	$2/kW	kW
Summer on-peak	$0.140	$0.020	$0.040	$0.20	kWh
Summer/winter mid-peak	$0.100	$0.015	$0.035	$0.15	kWh
Summer/winter off-peak	$0.070	$0.010	$0.020	$0.10	kWh
Super off-peak	$0.030	$0.010	$0.010	$0.05	kWh
Critical peak	Maximum 50 hours per year			$0.75	kWh

Source: Linvill et al. (2017). *Smart Non-Residential Rate Design.*

Good examples of actual retail rate designs that approximate what RAP recommends can be found across the country, but none adhere to all of those recommendations. For example, Oklahoma Gas & Electric offers a residential rate that includes not just peak and off-peak energy prices (a common approach), but also a critical peak price that applies to a limited number of high-demand hours per year. In Illinois, Commonwealth Edison has more than 10,000 residential customers enrolled on a voluntary, hourly energy price tariff. Several utilities, such as San Diego Gas & Electric, have adopted special tariffs for EV charging that are designed to encourage EV owners to save money by charging their vehicles during off-peak hours. And on the non-residential side, Sacramento Municipal Utility District offers a tariff that has a site infrastructure charge as RAP has recommended, along with "super peak" energy and demand charges.

RAP's retail rate design recommendations are crafted to be simple and understandable to customers, ensure that customers see prices that more accurately reflect the drivers of long-term utility costs than the prices in traditional rate designs, and reduce the likelihood that customers who have DERs will pay significantly less than their share of long-term system costs. With these rate designs, RAP believes that customer charges and demand charges that are only applied to DER customers will be unnecessary, although it may still be appropriate to assess an interconnection fee to these customers to recover the costs of processing and reviewing the interconnection application. However, it is still possible that customers who have DERs will be undercompensated for the utility services and societal values they provide.[93] **Special tariffs that apply only to customers who have DERs may remain appropriate if they provide a more accurate representation of the full net value of all the services that a customer who has a DER consumes from and provides to the system,** including value streams that are not compensated through standard retail rates or other means. (For example, the recommended rate design might not fully compensate DER participants for wholesale market price suppression benefits or the societal value of avoided emissions. Full net value can only be determined accurately through a case-by-case analysis by each utility or LSE, and the results will change over time.)

Retail rate designs can also address one of the key challenges of the existing utility business model: the "throughput incentive." Utility rates are designed to allow recovery of fixed and variable costs (including the utility's authorized rate of return), based on historical or projected levels

93 Overcompensation is also possible, although it will be less likely under the recommended rate structures than under traditional rate designs so long as the time-varying rates are a good approximation of long-term, time-varying utility costs.

Table 7. Summary of Recommendations: Smart Retail Rate Design (Tariffs)

	DER Owners	DER Aggregators	Utilities/ LSEs	State Utility Regulators	ISOs/System Operators	FERC/Other Federal Agencies
Customer charges: Only to recover costs that vary by number of customers			✔	✔		
Residential customer demand charges: To recover costs of final line transformer and service drop			✔	✔		
Non-residential customer demand charges: To recover costs of final line transformer and service drop and costs of any distribution system facilities designed to meet that customer's peak demand			✔	✔		
Residential customer energy charges: Simple TOU rate			✔	✔		
Non-residential customer energy charges: More complex time-varying rates, including real-time pricing, plus nodal pricing			✔	✔		
Compensate customers who are capable of injecting excess energy into the grid from a DER at the same time varying energy rates that they pay for energy consumption			✔	✔		
Consider special tariffs for customers who have DERs if they more accurately represent the full net value of the DER to the system			✔	✔		
Address the throughput incentive via a decoupling mechanism			✔	✔		

of energy sales. If energy sales exceed those assumptions but can be served with existing infrastructure, utility shareholders can exceed their authorized rate of return. This might happen, for example, if EV deployment exceeds expectations but managed charging is used to avoid the need for new capacity. But the opposite is also true: if energy sales are lower than expected, shareholder profits are at risk. PV, energy efficiency, and DR all reduce the utility's energy sales. Thus, utilities have an inherent throughput incentive in between rate cases to maximize energy sales. This incentive can be powerful enough to lead utilities to oppose or thwart policies and practices that reveal the value of DERs and compensate customers for installing them. Revenue decoupling is an elegant and commonplace solution to the throughput incentive.[94]

A decoupling mechanism can be added to the retail rate design recommended by RAP that automatically adjusts retail rates in between rate cases to account for unexpected changes in energy sales. A well-designed decoupling mechanism can eliminate or at least minimize the throughput incentive and reduce the risk that a utility will resist increased DER deployment by obscuring value or constraining compensation to DER owners. As of August 2018, 17 state PUCs had already adopted a decoupling policy for the electric utilities they regulate.[95]

Table 7 summarizes all the recommended elements of smart retail rate design and the parties that would need to act on each recommendation.

94 For comprehensive descriptions of the theory and application of revenue decoupling and explanations of how a decoupling mechanism can be tailored to meet the needs of any jurisdiction, refer to these two reference documents: The Regulatory Assistance Project. (2016). *Revenue Regulation and Decoupling: A Guide to Theory and Application*. Retrieved from https://www.raponline.org/knowledge-center/revenue-regulation-and-decoupling-a-guide-to-theory-and-application-incl-case-studies/ and Migden-Ostrander, J., and Sedano, R. (2016). *Decoupling Design: Customizing Revenue Regulation to Your State's Priorities*. Montpelier, VT: The Regulatory Assistance Project. Retrieved from http://www.raponline.org/knowledge-center/decouplingdesign-customizing-revenue-regulation-state-priorities

95 Sullivan, D., and DeCostanzo, D. (2018, August 24). Gas and Electric Decoupling [Blog post]. Natural Resources Defense Council. Retrieved from https://www.nrdc.org/resources/gas-and-electric-decoupling

C. Markets

Capturing greater value from DER combinations requires that the electric system become more transactive. DER combinations have capabilities that can serve needs on the distribution system and on the wholesale electric system, but exchange platforms do not currently exist to compensate owners for the utility system value provided by these capabilities. The range of services that may be offered to the distribution system operator (like local voltage support or local load shifting) and the wholesale electric system operator (like frequency response, energy, and capacity) have been enumerated elsewhere in this report. The common challenge that must be overcome to animate any of these utility system values is the creation or improvement of compensation mechanisms. As these mechanisms are created or improved, paying attention to the potential for double-counting or under-counting the resource's contribution to distribution system operators and bulk system operators is important.

Steps that can be taken to improve existing compensation opportunities for DERs on the wholesale electric system and create new market opportunities on both the wholesale and distribution systems include the following.

1. **Expand the range of energy prices allowed in wholesale markets**. Today's wholesale markets place a maximum value on energy prices. For example, the maximum value in PJM is $2,000 per MWh, whereas in ERCOT it is $9,000 per MWh.[96] Price caps have been adopted to minimize financial risk for LSEs and ratepayers, but they also send muted signals about the actual value of resources that can address short-term scarcity. This is especially true for emergency DR and energy storage resources. The value of these resources cannot be captured in wholesale markets so long as prices are artificially constrained. The solution is probably not to allow unlimited prices in the energy markets, but rather to adopt price caps that more closely reflect the average value of lost load. In ERCOT, for example, a report from London Economics in 2015 estimated the value of lost load for commercial and industrial customers to range from $3,000 per MWh to $53,907 per MWh.[97] In other words, many customers in ERCOT would be willing to pay more than the energy price cap if the alternative is to have scheduled or unscheduled power cuts. Some DR and energy storage resources might not be cost-effective from the participant's perspective under current price caps but could be cost-effective if price caps more accurately reflected the value of lost load.

2. **Institute a PRD program.** The distinction between PRD and DR resources is subtle but important. DR resources offer to curtail load when dispatched by the ISO and receive compensation at wholesale market energy rates for doing so. DR effectively operates as a supply resource, for reliability purposes. PRD resources, on the other hand, are not dispatched and do not receive wholesale market revenues. Instead, PRD resources commit to curtailing load any time the wholesale market energy price rises above a certain level chosen by the customer. PRD operates as a modification to load, for economic purposes. The customer chooses a price point at which they believe curtailment is cost-effective for them. By doing so, they help to lower demand and thus lower wholesale energy prices for all customers. PJM currently has a PRD program with very limited participation,[98] but this limited participation may be at least partly explained by PJM's relatively low energy price cap.

3. **Reform forward capacity markets** in places that currently have them, such as ISO New England and PJM. The first challenge is to define the capacity markets more narrowly to compensate those performance capabilities for which an adequate supply needs to be ensured. The second challenge

96 Refer to Kenney, S. (2018, May 2). *PJM Manual 11 Revisions: Price-Based Offer Caps* [Presentation before the Market Implementation Committee]. PJM. Retrieved from https://www.pjm.com/-/media/committees-groups/committees/mic/20180502/20180502-item-04c-m11-updates-for-price-based-offer-cap.ashx and Surendran, R., Hogan, W., Hui, H., and Yu, C. (2016, June). Scarcity Pricing in ERCOT [Presentation before a FERC Technical Conference]. Retrieved from https://www.ferc.gov/CalendarFiles/20160629114652-3%20-%20FERC2016_Scarcity%20Pricing_ERCOT_Resmi%20Surendran.pdf. The wide difference in these values is mostly caused by the existence of a capacity market in PJM but not in ERCOT. In ERCOT, a higher energy price may be needed to attract new generation, whereas in PJM new entrants can earn revenues through both the capacity and energy markets.

97 London Economics International, LLC. (2013). *Estimating the Value of Lost Load*. Briefing paper prepared for the Electric Reliability Council of Texas, Inc. Retrieved from http://www.ercot.com/content/gridinfo/resource/2015/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf

98 PJM. (2017). *Price Responsive Demand*. Retrieved from https://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/price-responsive-demand.ashx

is to refine those markets so that they fairly compensate any DERs or combinations of DERs that are able to provide those services. As more and more variable renewable generation is added to the grid, the need for resources that can maintain power quality — through voltage regulation, frequency response, fast ramping, and so on — will grow and DERs will likely be able to cost-effectively meet some of this need, if they can compete on an even playing field. Some have described the needed evolution as a **shift away from capacity markets to "capabilities" markets**.[99] Segmenting capacity markets to procure the right services at the right times will lead to better outcomes than, for example, offering a single annual capacity product.[100]

4. **Revise market rules, as necessary, to expand participation opportunities for DERs and DER combinations** in existing ISO market segments and compensation mechanisms. This revision should include two import aspects.

   a. Ensure that DERs and DER combinations are eligible to compete to provide any wholesale services they are capable of providing. Market rules sometimes define eligibility in ways that exclude DER participation, even if DERs can provide the same service that a large generator on automatic generation control can provide. This is particularly true for DER combinations, which generally are not eligible under existing market participation models. This must change. FERC already ruled to that effect in Order 841 for energy storage resources but deferred a decision on other DERs.[101] That docket remains open.

   b. The minimum size requirement for market participants should be no greater than is necessary to keep market operations reasonably manageable. Today there is a wide disparity in minimum offer/bid requirements across the ISOs that make DER participation more feasible in some markets than in others. Minimum thresholds in the energy markets range from 100 kW (in PJM, for example) to 5 MW (e.g., in the Midcontinent ISO, MISO). FERC, in Order 841, directed the ISOs to implement minimum size requirements for storage resources at a level no greater than 100 kW, but did not rule on minimum size requirements for other DERs. Some variation across DERs and across ISOs may be justifiable, but in all cases minimum size requirements should be based primarily on the need for efficient market operations, not on keeping things simple or convenient for the system operator.

5. **Expand opportunities for aggregators of DERs and DER combinations to compete in existing wholesale market segments including energy, capacity, and ancillary service markets.** Current FERC rules allow each Relevant Electric Retail Regulatory Authority[102] to preclude aggregators from bidding aggregated DR from within a utility's service territory directly into wholesale markets. Many states that allow their utilities to participate in an ISO do not allow third-party aggregators to bid DR directly into wholesale markets. This is true today across almost the entire footprints of MISO and Southwest Power Pool. Third-party aggregation of other DERs is technically and legally possible in all the ISOs but extremely limited in practice. There are historically valid reasons why some states object to third-party aggregators,[103] but if the goal is to capture the full utility system value of DER combinations, the role of aggregators is crucial. Most DER customers will not be large enough or have the wherewithal to participate in wholesale markets and capture that value without the assistance of an aggregator, so policies

99 See, for example Gimon, E., Aggarwal, S., and Harvey, H. (2015). *A New Approach to Capabilities Markets: Seeding Solutions for the Future*. Electricity Journal. Retrieved from http://dx.doi.org/10.1016/j.tej.2013.06.002 and Hogan, M. and Gottstein, M. (2012). *What Lies "Beyond Capacity Markets"?* The Regulatory Assistance Project. Retrieved from https://www.raponline.org/wp-content/uploads/2016/05/rap-hogan-whatliesbeyondcapacitymarkets-2012-aug-14.pdf

100 Some advocates go further, arguing that capacity markets subsidize the continued operation of otherwise uneconomic power plants, are not necessary to attract and maintain the generation capacity needed for resource adequacy, and should be completely eliminated. That debate is beyond the scope of this paper.

101 FERC, 2018.

102 Order 719 defined "Relevant Electric Retail Regulatory Authority" to mean the entity that has legal authority to set retail electric prices and competition policies for a utility. This is the state PUC for investor-owned utilities, and in some states for public power utilities or electric cooperatives as well. In other states, it may be the city council or an appointed governing board for a municipal utility, or the governing board of a cooperative utility. FERC. (2008). *Order No. 719: Wholesale Competition in Regions with Organized Electric Markets*. Docket Nos. RM07-19-000 and AD07-7-000. Retrieved from https://www.ferc.gov/whats-new/comm-meet/2008/101608/E-1.pdf

103 For example, some regulators have expressed concern that third-party aggregators will design programs to maximize the private benefits of DR resources for the aggregator and the participating customers, whereas utility-administered DR programs can be designed to maximize utility system benefits for all customers (not just participants).

that enable DER aggregation are essential. Furthermore, the perceived problems that states use to justify precluding aggregators can be addressed through careful oversight of aggregators, improved load forecasting and planning processes, use of AMI data, and other means. One option for states and utilities to consider is to test the feasibility and impacts of third-party aggregation through pilot programs, to reduce the risks (perceived or actual) of a more comprehensive change.

6. **Clarify long-term forecasted needs for more specific ancillary services or capabilities, and not just capacity**, through improved planning processes (more on this topic later). At the bulk power system level, the needed capabilities might include, for example, fast ramping capability or sustained ramping capability. At the distribution system level, the needed capabilities might include local voltage service or local load shifting service. **Establish competitive market products for procuring the resources that can meet those forecasted needs (i.e., capabilities markets).** The services that are needed to ensure resource adequacy and power quality on the distribution system will not be the same as those needed for the bulk power system. DERs that can meet those needs will have more value than resources that cannot.

7. **Establish or expand NWA processes to identify least-cost solutions to emerging system reliability issues and ensure DERs and aggregated DER combinations are eligible to bid into competitive procurement processes that address those issues.** FERC Order 1000,[104] which sought to reform electric transmission planning and cost allocation requirements for public utility transmission providers, required comparable consideration of transmission solutions and NWAs but did not establish minimum requirements governing which NWAs should be considered or how they should be evaluated. A more proactive approach to NWAs would be an improvement. For example, a report by the Department of Energy's Electricity Advisory Committee recommended that FERC consider using a planning guide that would "include such principles as conducting a high-level screen of [NWAs] to determine the viability of such approaches before conducting a more detailed analysis."[105] Also, Order 1000 did not establish a fully level playing field for NWAs because it does not guarantee that the costs of NWAs will be socialized in the same manner as the transmission costs they alleviate. In practice, the costs of a potential NWA project may fall mostly or entirely on ratepayers of a single utility, even though the benefits would be shared across the entire ISO footprint. In such cases, the potential project may not pass a C-E test from the perspective of the affected utility and thus may not be proposed or built, even if it would be cost-effective as a replacement for transmission investment when viewed from an ISO-wide perspective. This issue of cost allocation for NWAs is also worthy of reconsideration by FERC and the ISOs. NWAs can also provide solutions to distribution system challenges, just as they can on the bulk power system. FERC has no jurisdiction in this area; it is up to utilities and state regulators to require comparable consideration of NWAs on the distribution system.

8. **Identify emerging energy system priorities at the community or local government level (like local resiliency goals, local environmental goals, or local transportation electrification goals) that can potentially be served by DERs.** For example, communities in California or Illinois that opt to create a community choice aggregator often do so because they have renewable energy procurement goals that exceed the current legal obligations of their distribution utility. Not only can those needs be met through PV or other distributed renewables, but they can build the market for complimentary DERs such as electric storage and DR.

9. **Investigate establishing distribution-level competitive transactive markets for resources to meet distribution system needs.** Such markets have not been established to date anywhere in the United States, but they could evolve from existing competitive procurement mechanisms. The advantage of transactive distribution system markets over competitive procurement of resources is that transactive markets could

104 Federal Energy Regulatory Commission. (2011). *Order No. 1000: Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities.* Docket No. RM10-23-000. Retrieved from https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf?csrt=3882349678811403606

105 Electricity Advisory Committee. (2012). *Recommendations on Non-Wires Solutions*. Retrieved from https://www.energy.gov/sites/prod/files/EAC%20Paper%20-%20Recommendations%20on%20Non-Wires%20Solutions%20-%20%20Final%20-25-Oct-2012.pdf

better reflect the time-varying value of resources, as well as their actual (not forecasted) value. However, if distribution markets are established in areas that are served by an ISO, it will be necessary to coordinate distribution and wholesale markets to ensure that system operators are not expecting DERs to provide more than they are capable of providing. For example, if the distribution utility is counting on an energy storage resource to provide local voltage support at the same time the ISO is counting on the same resource to provide a fast ramping service, there may be a conflict. These types of conflicts can be resolved through careful design and coordination of the market participation rules at both levels and through non-performance penalties.

10. **Facilitate load registration mechanisms like the Open Energy Efficiency Platform, the Open Hosting Capacity Platform, and blockchain applications to resolve local reliability issues with decentralized solutions.** For example, one of the key challenges of the transition from a traditional focus on peak-shedding DR to consideration of shape, shimmy, and shift forms of DR is the need to identify and differentiate flexible loads. A registry of flexible loads can provide planners and distribution system operators with information about the resources potentially available to them. An open source platform for energy efficiency could validate load data and allow energy efficiency to be compensated directly for services rendered, obviating the need for costly EM&V procedures.

Table 8 summarizes all the recommended steps with respect to markets and the parties most likely to be involved in each step.

Table 8. Summary of Recommendations: Markets

	DER Owners	DER Aggregators	Utilities/ LSEs	State Utility Regulators	ISOs/System Operators	FERC/Other Federal Agencies
Expand range of energy prices allowed in wholesale markets					✔	✔
Institute price-responsive demand programs	✔	✔			✔	✔
Reform forward capacity markets, shifting to "capabilities" markets					✔	✔
Revise wholesale market rules to expand DER participation; allow DERs to provide any services they are capable of providing and base minimum size requirements on the need for efficient market operations					✔	✔
Expand opportunities for aggregators to compete in wholesale markets				✔		
Clarify long-term forecasted needs for specific ancillary services and establish capabilities markets, not just capacity markets					✔	✔
Establish processes to identify NWAs, including aggregations of DERs		✔	✔	✔	✔	✔
Identify community-level priorities that can be served by DERs			✔	✔		
Investigate establishing transactive markets to meet distribution system needs		✔	✔	✔		
Facilitate load registration mechanisms to resolve local reliability issues with decentralized solutions		✔	✔	✔		

D. Planning

Power sector planning can happen at three different levels, each of which creates an opportunity to identify and capture the value of DERs and DER combinations. First, FERC Order 1000 requires public utility transmission providers (including ISOs) to participate in coordinated, open, and transparent transmission planning processes at both the local level and the regional level. Planners in neighboring regions must coordinate their efforts to determine if their mutual needs can be satisfied through joint efforts more efficiently or cost-effectively than independent actions. Even though transmission planning is focused on the need for grid-scale resources, that need is shaped by the existence of DERs and should in turn shape the value of future DER deployments. Second, many utilities use IRP to identify the suite of resources that can meet the utility's expected long-term needs at least cost (while considering risk and uncertainty).[106] IRP is most commonly practiced by unrestructured utilities that own large-scale generation resources. Third, DSP (also known as integrated distribution planning or IDP) processes are beginning to take root in some states.[107] Much like the IRP processes that have sought for decades to minimize utility power supply costs, these newer DSP processes seek to minimize the costs of maintaining the distribution system.

1. Transmission Planning

Transmission planners need to develop improved tools and practices for forecasting system needs and identifying least-cost solutions. Four areas for potential improvement should be considered.

- **Better forecasts of generation from non-dispatchable, near-zero-operating-cost, variable energy resources like PV and wind are needed.** This includes the generation from distributed PV. Better weather models combined with detailed analyses of production from existing transmission-connected wind and solar resources will enable more accurate projections of the future energy and capacity contributions of variable energy resources at different times of day and in different seasons.

- Transmission planners also need to **account for the potential to activate flexible loads and energy storage devices** to reduce peak loads and maintain power quality on the bulk power system. The existence and success of today's DR programs illustrates the fact that some customers are willing and able to shift their demand in response to price signals. ISO New England and PJM allow DR resources to compete in future capacity markets, and they have historically been very active in those markets. But elsewhere, traditional load-shed DR is not considered as a capacity resource, other forms of flexible load (i.e., shape, shift, and shimmy forms of DR) are not considered at all, and loads are assumed to be nearly or completely price-inelastic. Distributed energy storage devices can be operated to provide similar services to DR, and combinations of DR, storage, and other DERs could potentially contribute as well. Better analytical tools and improved practices would enable transmission planners to evaluate the potential for flexible load (including PRD) and compare the costs of activating DER potential to the costs of transmission congestion or transmission expansion.

- As previously noted, planners should also **clarify long-term forecasted needs for more specific ancillary services or capabilities** (e.g., fast ramping capability and sustained ramping capability) and not just capacity. This is a prerequisite for creating transactive markets to procure such capabilities.

- Transmission planners should **be proactive in soliciting NWAs**, as noted in the transactive markets section of this report. FERC Order 1000 requires planners to consider NWAs, but that presupposes the planners are presented with NWAs to consider. This is rarely the case in practice. The current approach is reactive; a proactive approach to NWAs could lead to more reliable and less costly bulk power solutions as the case study above demonstrates.

106 "IRP" is commonly used to describe either the planning process or the resultant plan. IRP is required by about half of U.S. states for at least some of the utilities in those states. See Wilson, R., and Biewald, B. (2013). Best Practices in Electric Utility Integrated Resource Planning. Synapse Energy Economics for The Regulatory Assistance Project. Retrieved from https://www.raponline.org/wp-content/uploads/2016/05/rapsynapse-wilsonbiewald-bestpracticesinirp-2013-jun-21.pdf

107 See, for example, Cooke et al., 2018.

2. Integrated Resource Planning

Utilities that develop IRPs can also improve their practices to better account for the potential of DERs to meet customers' needs more reliably, at lower cost, or with less risk. Areas for potential improvement in IRP include the following.

- Utilities need to **develop more accurate long-term load forecasts, accounting for utility-scale variable energy resources and DERs** — including variable DG, storage, and flexible loads. This mirrors the opportunity for improvement in transmission planning but is even more important, because utilities must consider the impacts of behind-the-meter DERs they cannot control and consider needs at a more granular local level. Utilities must also understand in detail their energy, capacity, and ancillary service needs to identify the least-cost, least-risk suite of resources that will suffice.

- The production cost models used to develop IRPs generally cannot model supply and demand in sub-hourly increments, but variations in sub-hourly supply and demand are crucially important for revealing the need for ancillary services and the value of flexible loads, traditional DR, and storage resources. Most of the production cost models available today are proprietary software sold by private companies, but utilities and regulators can both **stimulate the demand for more sophisticated models and work with vendors to develop practical solutions** to this challenge.

- Although the IRP process purports to find the least-cost solution to long-term power needs, many utilities artificially constrain the contributions that DERs can make in order to simplify the modeling exercise. For example, rather than establishing energy efficiency procurement levels by optimizing for total long-term system cost, most IRPs assume certain amounts of energy efficiency will be procured annually — for example, just enough to meet the minimum requirements of a state-mandated energy efficiency resource standard. These kinds of constraints should be eliminated. Customers are best served if the IRP process **assesses all resources, utility-scale and distributed, supply-side, and demand-side, on an equal basis.** The Seventh Power Plan developed by the Northwest Power and Conservation Council offers a good example of an IRP that avoids placing artificial constraints on the contributions of DERs, but even that excellent example leaves some room for improvement.[108]

- The best IRP processes **include an assessment of risks and uncertainties**. The preferred portfolio of resources is not necessarily the one that is least costly under "base case" assumptions but could be one that is relatively inexpensive under a wide variety of potential scenarios including the base case. A process that considers risk and uncertainty in this manner acknowledges our limitations to predict the future. It also tends to reveal a higher value, all else being equal, for resources that can be procured in small increments (like DERs) and resources that are flexible (like storage and DR). Combinations of different types of DERs may further reduce risk because they enhance the options for creating value.

- Many IRPs **include consideration of costs and benefits that are not directly related to operation of the power system (i.e., non-energy impacts).** It is commonplace to attach an assumed monetary cost to greenhouse gas emissions, for example, even in jurisdictions where such emissions are not currently regulated, and generators pay no cost for emissions. Such costs then become part of the calculus of determining which portfolio of resources can meet long-term needs at least-cost (considering risk). This is the IRP equivalent of using the SCT or RVT instead of a PAC Test, as explained in the section on C-E tests in Section II of this report. Consideration of non-energy impacts from an SCT or RVT perspective will better reveal the value of DERs and should be a routine part of IRPs.

- IRPs generally attach no value to resilience. Resources that can serve critical loads during grid outages are not given any "credit" for that capability, and this leads to a systematic undervaluing of microgrids. This is especially true for combinations of DERs that enable critical facilities (e.g., military bases, police and fire stations, hospitals, and cell towers) to continue

108 Northwest Power and Conservation Council. (2016). *Seventh Northwest Conservation and Electric Power Plan*. Retrieved from https://www.nwcouncil.org/reports/seventh-power-plan

providing public services during power outages. Utilities should seek to **quantify the public benefits of resilient power systems (i.e., monetize the value not from the participant perspective but from the societal perspective of having microgrids that can serve critical public loads during grid outages) and account for those benefits when determining the preferred resource portfolio** for meeting long-term needs.

3. Distribution System Planning

As suggested in the section on transactive markets, utilities and state PUCs could adopt some sort of formal DSP process to transparently identify long-term needs for energy, capacity, and ancillary services on the distribution system at a granular level. DSP processes will be a crucial tool for identifying system needs that can be met through DER deployments, communicating those needs and the associated utility system values, and then satisfying those needs through competitive procurement processes in which DERs are allowed to compete as NWAs. Although DSP is a relatively new development in utility regulation,[109] numerous reports have been published recently offering guidance, examples, and case studies.[110] Steps that can be taken in DSP processes to identify and capture DER value are similar to those for transmission planning and IRP and include the following.

- Utilities should develop and **use improved techniques for long-term load and DER deployment forecasts.**
- Utilities should **proactively solicit NWAs** to determine if identified distribution system needs can be met at a lower cost than through a utility infrastructure investment. The Brooklyn-Queens Demand Management and Oakland Clean Energy Initiative examples cited in the NWA use case explanation presented earlier demonstrate the potential value of NWAs for reducing distribution system costs.
- Utilities should **assess the "hosting capacity" of their existing system and make hosting capacity maps publicly available.**[111] These maps can indicate to customers and third-party DER developers where it is likely possible to interconnect DERs without triggering the need for system capacity upgrades. The Interstate Renewable Energy Council published a useful guide for regulators on why and how to do a hosting capacity analysis.[112] As California, New York, Hawaii, and others have initiated hosting capacity analyses, they have discovered that hosting capacity limits stem from multiple reliability conditions. In recognition of this, the Electric Power Research Institute (EPRI) produced a hosting capacity analysis tool that identifies thermal, power quality, protection, and safety criteria that can limit DER growth and potentially drive the need for physical distribution investment.[113] Assessing hosting capacity based on multiple criteria can reveal instances where a standalone PV system would trigger the need for a capacity upgrade, but combining the PV with another type of DER will alleviate the specific constraint.

Finally, opportunities exist to better integrate and coordinate planning processes across the transmission, generation, and distribution domains. If decisions about potential investments are being made in each area in isolation and using different methods and assumptions, it will be difficult or impossible to ensure that the value of DERs (which create value in all three domains) is appropriately considered. The first step in addressing this challenge is to **ensure that information is efficiently flowing between these different planning domains and that consistent assumptions and methods are being used.** LBNL researchers considered all three domains in a 2016 report that discusses opportunities for improving the

109 All utilities plan for the future of their distribution system, but not necessarily in a manner that is transparent to their customers, interested parties, or regulators.

110 See, for example: Cooke et al., 2018; Volkmann, 2018; and Smart Electric Power Alliance and Black & Veatch. (2017). *Beyond the Meter – Planning the Distributed Energy Future; Volume II: A Case Study of Integrated DER Planning by Sacramento Municipal Utility District*. Retrieved from https://sepapower.org/resource/beyond-meter-planning-distributed-energy-future-volume-ii/

111 Alternatively, third-party service providers may ultimately be successful in producing hosting capacity maps using publicly available data, utility-provided data, or a combination of sources. For an article exploring this possibility, see: Tweed, K. (2016, September 20). Kevala Builds a National Map of Solar's Locational Value. *Greentech Media*. Retrieved from https://www.greentechmedia.com/articles/read/kevala-builds-national-map-of-locational-value-of-solar#gs.1htdjl

112 Stanfield, S., Safdi, S., and Baldwin Auck, S. (2017). *Optimizing the Grid: A Regulator's Guide to Hosting Capacity Analyses for Distributed Energy Resources*. Interstate Renewable Energy Council. Retrieved from https://irecusa.org/publications/optimizing-the-grid-regulators-guide-to-hosting-capacity-analyses-for-distributed-energy-resources/

113 Electric Power Research Institute. (2016). *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State*. Retrieved from https://www.epri.com/#/pages/product/3002008848/?lang=en

treatment of distributed PV in resource planning processes.[114] Similar research addressing other DERs would be valuable.

Table 9 summarizes all the recommended steps with respect to planning and the parties most likely to be involved in each step.

Table 9. Summary of Recommendations: Planning

	DER Owners	DER Aggregators	Utilities/ LSEs	State Utility Regulators	ISOs/System Operators	FERC/Other Federal Agencies
Transmission planning						
Better forecasts from variable renewables					✔	
Account for potential to activate flexible loads and energy storage devices					✔	
Clarify long-term needs for capability, not just capacity					✔	
Solicit NWAs					✔	
Integrated resource planning						
Develop more accurate long-term load forecasts			✔	✔		
Develop more time-dynamic forecasting models			✔	✔		
Remove constraints on DERs; assesses all resources on an equal basis			✔	✔		
Assess risks and uncertainties			✔	✔		
Consider non-energy impacts			✔	✔		
Account for the resilience value of DERs that serve critical public infrastructure			✔	✔		
Distribution system planning						
Improve forecasting			✔	✔		
Solicit NWAs			✔	✔		
Assess hosting capacity and make hosting capacity maps publicly available			✔	✔		
Coordination of planning efforts						
Share information across planning domains and use consistent assumptions and methods			✔	✔	✔	

114 Mills, A., et al. (2016). *Planning for a Distributed Disruption: Innovative Practices for Incorporating Distributed Solar into Utility Planning*. Lawrence Berkeley National Laboratory for U.S. Department of Energy. LBNL-1006047. Retrieved from http://eta-publications.lbl.gov/sites/default/files/lbnl-1006047.pdf

E. Utility Procurement

Utilities procure resources or the output from resources for varying reasons and through varying mechanisms. Federal rules, promulgated by FERC to implement portions of PURPA, require utilities (with some exceptions) to purchase energy and capacity from qualifying small power production facilities and cogeneration facilities at just and reasonable rates.[115] Utilities may also need to comply with a state policy mandate, such as an RPS or energy efficiency resource standard, that requires their purchase of specific resource types. And utilities of course will procure resources that have been identified (perhaps but not always through an IRP or DSP process) as needed to meet customer demand. Some of the procurement-related actions that will lead to capturing value from DERs have already been noted, but they will be briefly repeated here along with some actions not yet discussed.

1. State regulators have authority (again, with some exceptions) to establish the just and reasonable rates that regulated utilities offer as compensation to PURPA qualifying facilities. PURPA stipulates that PUCs shall not order a utility to offer rates that exceed the utility's avoided costs, but states have some latitude in interpreting avoided costs.[116] PURPA rates are sometimes based on avoided short-term energy costs and nothing else. At a minimum, **regulators could include avoided line losses, any demonstrable avoided capacity costs, and avoided costs of compliance with state renewable energy mandates** (where applicable) without violating PURPA.

2. Where specific resources like energy efficiency and DR are procured through utility *programs*, it is best to **evaluate the C-E of all programs using the same C-E test. Ideally this will be the SCT or a version of the TRC or RVT that considers relevant non-energy costs and benefits**, for reasons previously noted. Use of a more restrictive cost-effectiveness test will undervalue DERs and use of different tests for different resource types will lead to a suboptimal allocation of ratepayer resources.

3. Introducing competition to utility procurement is an essential step in revealing DER value. Any time utilities are allowed to build or contract with resources without soliciting competitive bids, there is a serious risk that ratepayers will pay more than they should. Ideally, whenever a utility identifies a system need, they will **use a competitive, all-source procurement process** to find the least costly way to meet the need. All-source procurement requires the utility to specify the capabilities they need, rather than the resources type(s) they seek to procure. This will harmonize compensation opportunities for all resource solutions, including DERs and combinations of DERs, ensure a level playing field, and provide the best value for ratepayers. Furthermore, where utilities are not fully restructured, it is possible and advisable for regulators to **require utilities to evaluate third-party–owned solutions, including DER combinations and aggregations of DERs, as an alternative to a utility-owned resource.** For example, regulated utilities in Colorado acquire resources identified in their IRPs through a competitive procurement process, but the utilities themselves are allowed to offer self-build proposals. Safeguards are in place to ensure that self-build proposals compete on a fair basis with third-party–owned solutions.

4. In the United States, investor-owned utilities earn returns for their shareholders almost entirely through capital investments in generation, transmission, and distribution system infrastructure. They are generally precluded from earning any return on operating expenses. In other words, to earn profits for shareholders — which is their fiduciary responsibility — utilities generally must build and own tangible things. The inherent incentive to maximize capital investment in order to maximize profits, even when such investment is inefficient, is described as the utility capital expenditure ("capex") bias or, in academic circles, the Averch-Johnson effect.[117] So long as the capex bias remains an essential feature of our utility regulatory system, regulation will be necessary to protect ratepayer

115 18 CFR § 292.303-304.

116 The question of how to interpret and calculate avoided costs is not straightforward and has been extensively debated and litigated. In response to a petition from the California Public Utilities Commission, FERC issued a clarification in 2010 of how it interprets avoided costs. Refer to: 133 FERC ¶ 61,059 (2010) (October 21 *Order Granting Clarification and Dismissing Rehearing).* This FERC order provides a good summary of many of the issues and numerous references to relevant case law.

117 Averch, H., and Johnson, L. (1962). *Behavior of the Firm Under Regulatory Constraint.* American Economic Review. 52 (5): 1052–1069.

interests. Utilities have a built-in disincentive to facilitate or encourage DERs, or any solution to a system need that reduces the opportunity for capital investments of shareholder equity. The long-term solution to this dilemma is probably to **reconsider the utility business model such that shareholder returns depend less on capex and more on total expenditures ("totex") or performance against goals relating to the public interest and customer preferences.** Several recent reports by state PUCs and others have investigated totex regulation and other forms of "performance-based regulation" as a partial replacement or supplement to the capex model,[118] and this idea is worthy of consideration everywhere.

Table 10 summarizes all the recommended steps with respect to utility procurement and the parties most likely to be involved in each step.

Table 10. Summary of Recommendations: Utility Procurement

	DER Owners	DER Aggregators	Utilities/ LSEs	State Utility Regulators	ISOs/System Operators	FERC/Other Federal Agencies
Include avoided line losses, avoided capacity costs, and avoided costs of compliance with state renewable energy mandates in PURPA rates			✔	✔		
Apply the same cost test to all utility procurement programs, ideally the SCT or a version of the TRC or RVT that considers relevant non-energy costs and benefits			✔	✔		
Use competitive all-source procurement processes and require utilities to evaluate third-party–owned solutions			✔	✔		
Avoid capex bias: consider totex or performance-based regulation			✔	✔		

118 See, for example: Michigan Public Service Commission. (2018). *Report on the Study of Performance-Based Regulation.* Retrieved from https://www.michigan.gov/documents/mpsc/MI_PBR_Report_Final_621112_7.pdf; Littell, D., et al. (2017). *Next-Generation Performance-Based Regulation: Emphasizing Utility Performance to Unleash Power Sector Innovation.* The Regulatory Assistance Project and National Renewable Energy Laboratory. Retrieved from https://www.nrel.gov/docs/fy17osti/68512.pdf; and Advanced Energy Economy Institute, America's Power Plan, and Rocky Mountain Institute. (Undated). *UK'S RIIO – A Performance-Based Framework for Driving Innovation and Delivering Value.* Retrieved from https://info.aee.net/hubfs/RIIO%20Case%20Study%20Final%20.pdf

VII. Conclusion

When consumers install PV and other DERs, they usually do so only after determining that they will be able to recover their costs through reduced energy bills. The rapid growth in distributed PV and distributed energy storage systems and the projected growth in EVs offers clear evidence that participants are realizing value from DERs — but this alone doesn't imply that they are capturing as much value as they could or should. DER deployment is hindered today because some of the DER value streams are not being captured at all, and in other cases customers are not being fully compensated for the utility system or societal value of these resources. Geographic variations in the ability of customers to capture some value streams are undoubtedly one of several factors that explain the uneven deployment rates for DERs across states.

For example, the potential societal benefits of DERs (e.g., employment impacts or public health benefits from reduced air pollution) have largely not been captured to date. Where DERs are deployed through ratepayer-funded programs, societal benefits are sometimes monetized and factored into decisions using the SCT, and VOS tariffs may also explicitly account for societal benefits. But in many jurisdictions societal benefits are completely excluded from C-E tests, and the price signals inherent in retail electricity tariffs and wholesale electricity market prices mostly ignore societal benefits.[119]

The past five years have been an incredibly active era for innovation in the power sector, with technology developers racing to meet growing consumer demand for DERs, states filling their traditional role as "the laboratories of democracy," and ISOs testing different market products and market rules. Although many questions are still unanswered and much work remains, some of the innovations have already proven to be successful in terms of overcoming barriers to DER deployment and revealing and capturing more of the value that DERs offer.

The value of some DER services may be compensated through tariffs, by markets, or through power purchase agreements. This requires better identifying and translating utility system needs into discrete services and then designing markets and procurement processes in which DERs can fully compete to provide those services. Some values may be quantified by the regulator through a resource planning process, in which avoided utility system costs are calculated and societal values are translated from policy into compensated value by administrative fiat. (The RVT, for example, is specifically designed to add public policy values to a standard PAC test.) Then there are values that depend on who owns and controls the DER and how they use it to maximize their own value. We can elucidate these concepts by referring to several examples.

- When a utility owns DERs and uses them to minimize cost (as in a public power utility) or maximize shareholder value (as in an investor-owned utility), they can deploy the resource without either creating a market or requiring an administrative determination. Take storage for example — the highest value use of storage may include reserving its use for local voltage control, but there is no market for local voltage control. One could after a long administrative process determine that there is value in acquiring storage for voltage control, or the utility, which has private information about system needs, may see a local voltage problem emerging and need to find a solution. The key features in this example are private information and a utility objective.

- When the consumer owns DERs, the consumer can reserve their use for resilience — specifically the consumer's own resilience. The key features in this example are private value (i.e., the consumer's objective may be different from that of other consumers owing to the nature of the business they are in or because of personal preferences), private information

119 In states that have established RPS or carbon allowance trading programs, one could argue that tariffs and prices inherently reflect *some* of the societal benefits of renewable energy or carbon emission reductions, but certainly not all the benefits. RPS and carbon requirements are never established based on C-E criteria or net societal benefits. They tend to be legislated or administratively established targets, for which regulated entities seek to find the cheapest compliance options.

about the underlying value of DERs, and the absence of market or administrative processes to fulfill that value.

- When a group of consumers own DERs collectively, they can use them to meet collective (perhaps community) needs. This has been part of the story with community choice aggregation, such as in the cities of Boulder, Colorado; Taos, New Mexico; Georgetown, Texas; and other places. Although most discussion to date of the new RVT has focused on the value of resources in meeting state policy objectives, the test can and should also acknowledge community values. So if a community has environmental goals that are more aggressive than state goals, or if a community has economic development goals, resiliency goals, and the like, there is latent community value that is not expressed in either markets or administrative rate-making processes. The key to this example is private information about value, community values, and expression of that value through ownership and control.
- There are and always will be transaction costs associated with the market and administrative process innovations that reveal and compensate for certain value streams. Sometimes it will be too expensive to create a market for a service, and sometimes it will be too expensive to create an administrative process to value a service.
- As these examples illustrate yet again, it is impossible to consider value without considering value "to whom." Sometimes the value of DER combinations is apparent and significant enough to spur action, but sometimes the transaction costs of capturing the value through markets or administrative process is too high. Absent some of the changes described in Section VI,, ownership and control of DERs by a single party will remain the only or the most cost-effective solution to obtaining value, even though the aspirational goal of capturing full value will remain elusive.

In recent years, power sector stakeholders have focused on the benefits of technology in better defining system needs and enabling customers to participate in meeting system needs, but they haven't focused sufficiently on the ability of technology to allow needs that have heretofore remained unexpressed to become expressed. People have always had heterogeneous preferences, and communities have heterogeneous preferences as well, but transaction costs have always been too high for these heterogeneous preferences to be pursued. Information, communications and control technologies, along with much more cost-effective DERs, have lowered transaction costs to the point that latent preferences can now be expressed and can enter into the overall calculus of C-E.

This report offers descriptions of four different use cases that are increasingly revealing the potential value of DER combinations. Perhaps more important, it outlines a comprehensive path forward to capture more of the value of DERs and DER combinations through specific actions that can be taken by a variety of power sector stakeholders: federal regulators, state regulators, utilities, ISOs, DER technology developers, and others. Every one of those actions can help, and a commitment to implementing them all is not necessary. The important thing is to get started now.

The highest priority actions will vary by stakeholder and by location. Each group of stakeholders has the ability to act independently on some recommendations. There is no reason to wait for someone to develop a comprehensive action plan or for consensus to be reached on all issues. Some suggestions on priorities are possible. In general, the action items in Section VI, Part A are necessary prerequisites for many of the action items recommended elsewhere in Section VI. Work on those items should commence as soon as possible. Similarly, the adoption of smart retail rate designs featuring time-varying energy rates, at a minimum for customers who have DERs, is another action that unlocks the potential of a variety of other recommendations. And finally, on an issue that relates to several of the recommendations, utilities and their regulators should prioritize investigating NWAs to infrastructure investments, at least on a pilot basis, to better understand and reveal the potential system values of DERs.

Appendix: Background on the Potential Value Streams of DERs

This report aims to develop a path forward for capturing more value from combinations of PV and other DERs. To establish a foundation, it is helpful to review a sampling of the literature describing actual and potential value streams that have been identified for each type of DER when deployed as a single resource. The studies cited in this Appendix are not intended to serve as an exhaustive literature review, but rather to provide insights into some of the methods and issues associated with valuing each type of DER. Each study took a unique approach to categorizing costs and benefits, identifying which costs and benefits are relevant from each stakeholder perspective (and thus under each C-E test), and visually presenting the results. We leave it to future authors to synthesize the results into a common framework for C-E testing of all DER types, as this would constitute a major project that is beyond the scope of this report.

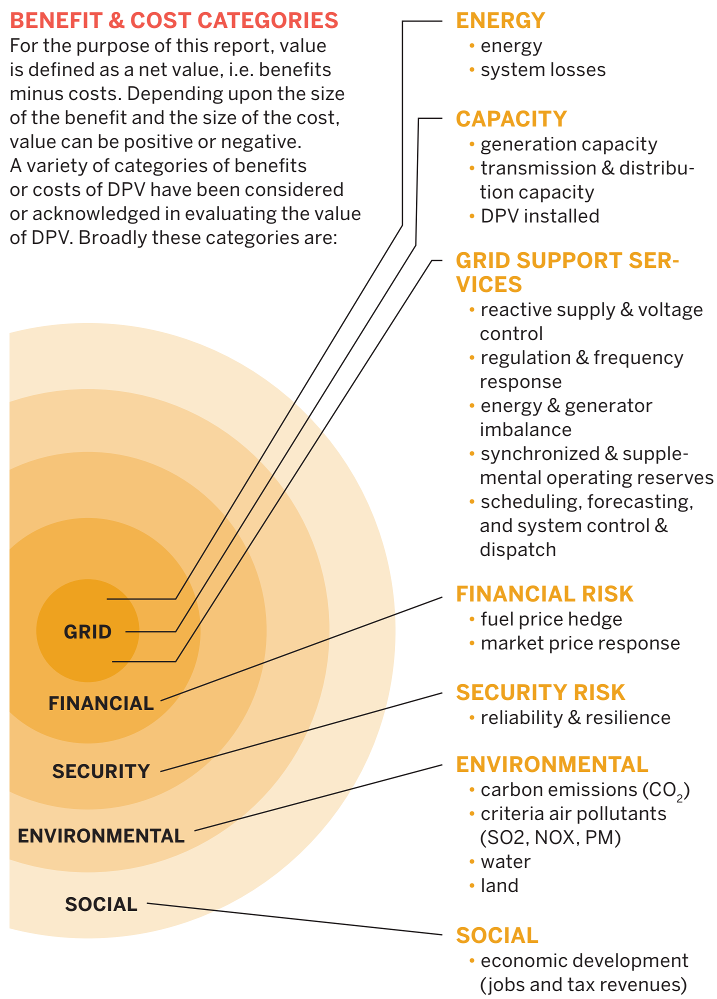
A. Solar PV

The Solar Energy Industries Association cites nearly 50 studies that have evaluated the costs and benefits of solar PV generation.[120] Many of these studies have examined the question broadly, but nearly half the cited studies pertain to the value of solar in a particular state or for a particular utility. These studies were developed for different purposes: in some cases, to judge the value of solar, and in other cases to determine whether NEM tariffs were overcompensating or undercompensating customers who have PV, based on value to the utility system. Although each study has contributed to our understanding, we will introduce the topic at a high level by referring to a single report that summarized multiple studies.

The Rocky Mountain Institute (RMI) produced a report in 2013 that examined the methodologies and results of 16 value of distributed solar PV (DPV) studies published up to that year.[121]

The RMI report identified three broad differences among these studies: 1) the perspectives (C-E tests) used to assess value; 2) the value streams considered; and 3) the assumptions and methods used to quantify value. RMI summarized the potential utility system and societal value streams that could be associated with DPV in Figure A-1.

Figure A-1. Potential Costs and Benefits (Value Streams) of DPV Systems



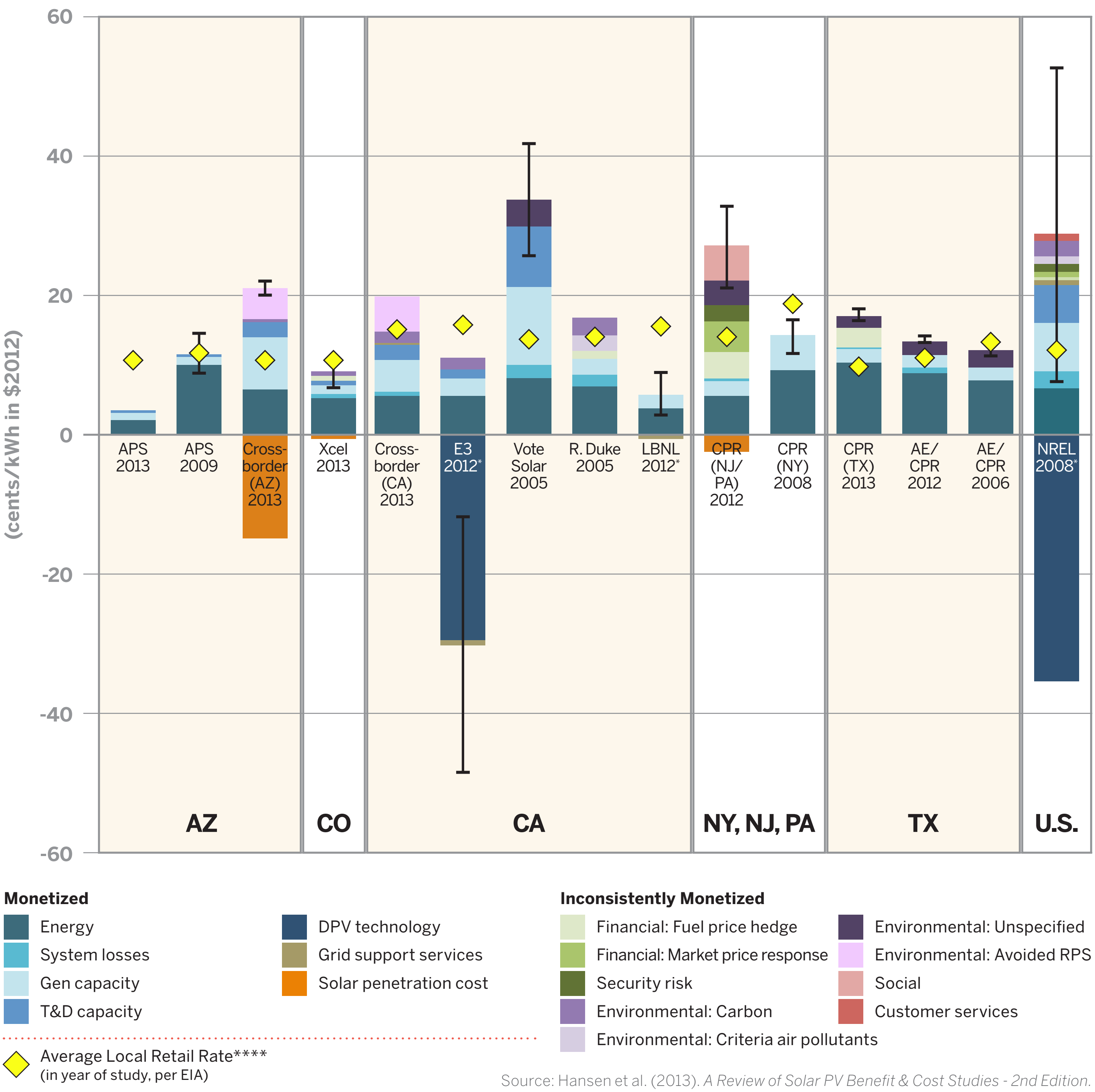
Source: Hansen et al. (2013). *A Review of Solar PV Benefit & Cost Studies - 2nd Edition.*

120 Solar Energy Industries Association. *Solar Cost-Benefit Studies* [Webpage]. Retrieved from https://www.seia.org/initiatives/solar-cost-benefit-studies

121 Hansen, L., Lacy, V., and Glick, D. (2013). *A Review of Solar PV Benefit & Cost Studies - 2nd Edition*. Rocky Mountain Institute. https://rmi.org/wp-content/uploads/2017/04/eLab_DERBenefitCostDeck_Report_2013-1.pdf

The RMI report also summarized the quantitative results of the 16 value of solar studies in a chart, shown in Figure A-2, that indicates the relative contribution of different value streams to the total value of solar. Of importance, the report notes that none of the reviewed value of solar studies had quantified all the potential value streams shown in Figure A-1.

Figure A-2. Benefits and Costs of DPV by Study



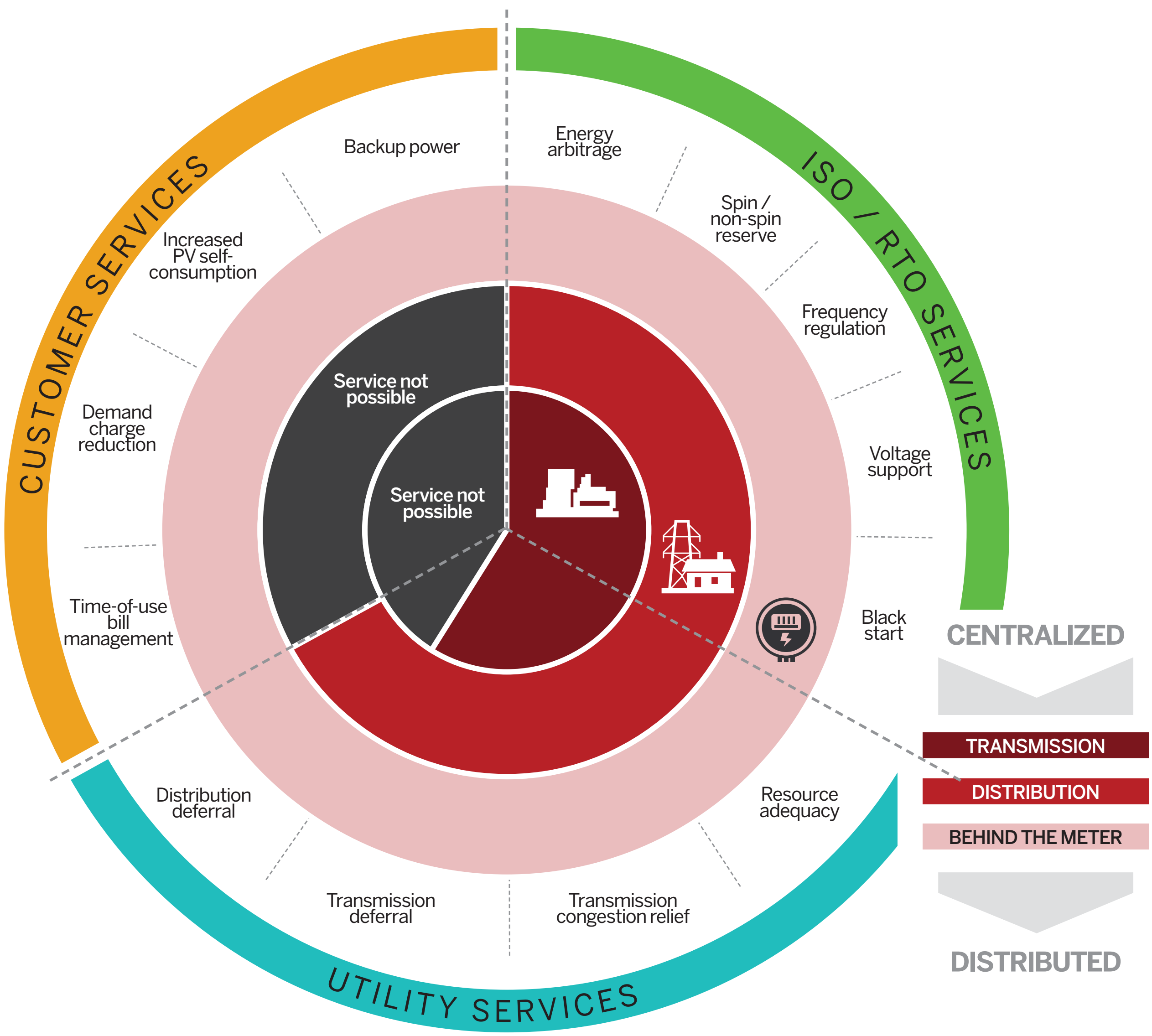
Source: Hansen et al. (2013). *A Review of Solar PV Benefit & Cost Studies - 2nd Edition.*

B. Energy Storage

A few similar studies and reports have been published that aim to identify and assess value streams for energy storage. Two of the more noteworthy examples have been published by RMI[122] and by the California Public Utilities Commission.

RMI examined several studies of the value of battery energy storage systems in a manner similar to their meta-analysis of the value of DPV. Figure A-3, excerpted from the RMI report, identifies 13 potential services (i.e., value streams) of battery energy storage systems and the party to whom each value accrues. As the figure indicates, the value streams for battery energy storage depend in part on where the system is located — behind the customer's meter, on the distribution system, or on the transmission system. (Note: Societal value streams such as avoided emissions were not considered in this report.)

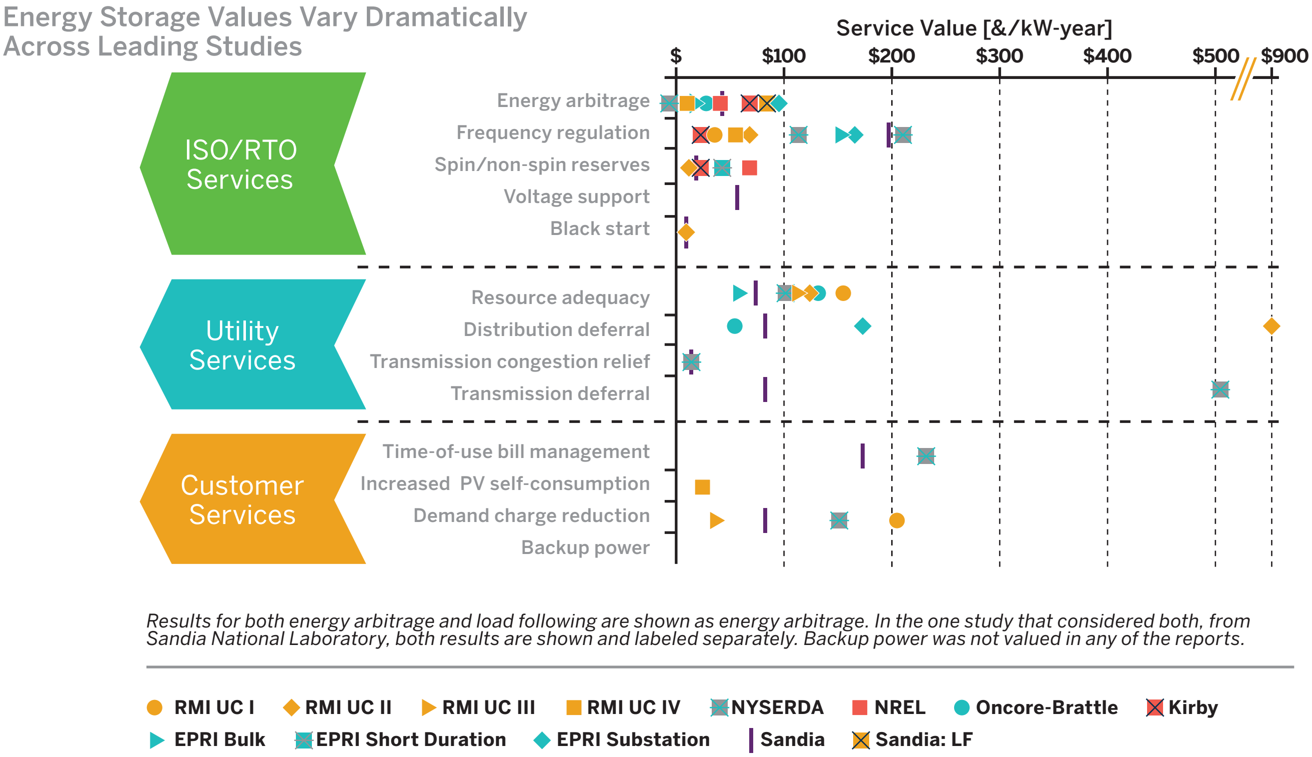
Figure A-3. Potential Services (Value Streams) of Battery Energy Storage Systems



Source: Fitzgerald et al. (2015).

122 Fitzgerald, G., Mandel, J., Morris, J., and Touati, H. (2015). *The economics of battery energy storage: How multi-use, customer-sited batteries deliver the most services and value to customers and the grid.* Rocky Mountain Institute. Retrieved from http://www.rmi.org/electricity_battery_value

Figure A-4. Contributions of Value Streams to Total Value of Battery Energy Storage



Source: Fitzgerald et al. (2015).

RMI summarized the quantitative results of the reviewed studies in the chart shown in Figure A-4 above, which indicates the contribution of different participant and utility system value streams to the total value of battery energy storage.

In January 2018, the California PUC issued a decision providing guidance to California utilities on how to enable energy storage resources to capture their full economic value and adopt rules for assessing value.[123] The California PUC decision focused on "multiple-use applications" of energy storage, meaning applications where the storage resource is capable of providing services and value to more than one party (i.e., the customer, the distribution utility, or CAISO). Unlike the previously cited RMI report, the CPUC decision was not limited in scope to battery storage, but like the RMI report it did not assess societal value streams.

The California PUC approached the question of utility system and participant value streams by defining five "domains" for which energy storage can provide value: three "grid domains" and two "service domains." Domains answer the question, "What entity receives the benefit or value of a service provided by energy storage?" Grid domains indicate the point of interconnection of the storage system and mirror those used by RMI. For grid domains, value is received by the customer, the utility responsible for the distribution system, or the entity responsible for the transmission system. Service domains reflect two of the key services associated with bulk power system reliability: operation of the wholesale electricity market and resource adequacy. The entity responsible for each of those services can benefit from some of the capabilities of energy storage. For each domain, the California PUC identified value streams relating to reliability services and non-reliability services, as summarized in Table A-1 (adapted from the CPUC decision).

123 CPUC. (2018). *Decision on Multiple-Use Application Issues.* Decision 18-01-003 in Rulemaking 15-03-011. Retrieved from http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M206/K462/206462341.PDF

Table A-1. Domains and Potential Services of Energy Storage

Domain Type	Domain	Reliability Services	Non-Reliability Services
Grid	Customer	None	• TOU bill management • Demand charge management • Increased self-consumption of onsite generation • Backup power • Supporting customer participation in DR programs
Grid	Distribution	• Distribution capacity deferral • Reliability (back-tie) services • Voltage support • Resiliency/microgrid/islanding	• None
Grid	Transmission[124]	• Transmission deferral • Inertia • Primary frequency response • Voltage support • Black start	• None
Service	Wholesale market	• Frequency regulation • Spinning reserves • Non-spinning reserves • Flexible ramping product	• Energy
Service	Resource adequacy	• Local capacity • Flexible capacity • System capacity	

Source: Adapted from CPUC. (2018). *Decision on Multiple-Use Application Issues*.

C. Energy Efficiency

Although the CaSPM provided the foundation for virtually all subsequent work on evaluating the costs and benefits of energy efficiency, the manual included only cursory descriptions of the potential cost and benefit categories. The benefit categories (i.e., value streams) specified in the CaSPM include avoided energy costs as well as avoided generation, transmission, and distribution capacity costs. The CaSPM also offered a short list of externalities for consideration when an SCT is used. These externalities include avoided environmental damage, increased system reliability, fuel diversity, avoided risk and risk management costs, and "non-energy benefits." The manual clearly states that this list of externalities is not exhaustive, and indeed, many jurisdictions have invested tremendous amounts of time in more thoroughly defining the value streams of energy efficiency.

In 2013, RAP published what is perhaps the most comprehensive review to date of the potential value streams of energy efficiency measures and programs.[125] Although similar to the illustrative list of DER value streams in Table 2 (from Section II of this report), the RAP report identified many more potential benefits. Table A-2 summarizes those benefits and the C-E tests in which they could be included. The one notable value stream from Table 2 that energy efficiency (as traditionally defined[126]) cannot provide is avoided ancillary service costs.

124 The CPUC order further notes that, "voltage support, inertia, and primary frequency response have traditionally been obtained as inherent characteristics of conventional generators, and are not today procured as distinct services. We include them here as placeholders for services that could be defined and procured in the future by the CAISO."

125 Lazar, J., and Colburn, K. (2013). *Recognizing the Full Value of Energy Efficiency*. The Regulatory Assistance Project. Retrieved from https://www.raponline.org/knowledge-center/recognizing-the-full-value-of-energy-efficiency/

126 Some types of energy-efficient appliances could potentially vary their power consumption to provide ancillary services, but this paper treats all such "flexible

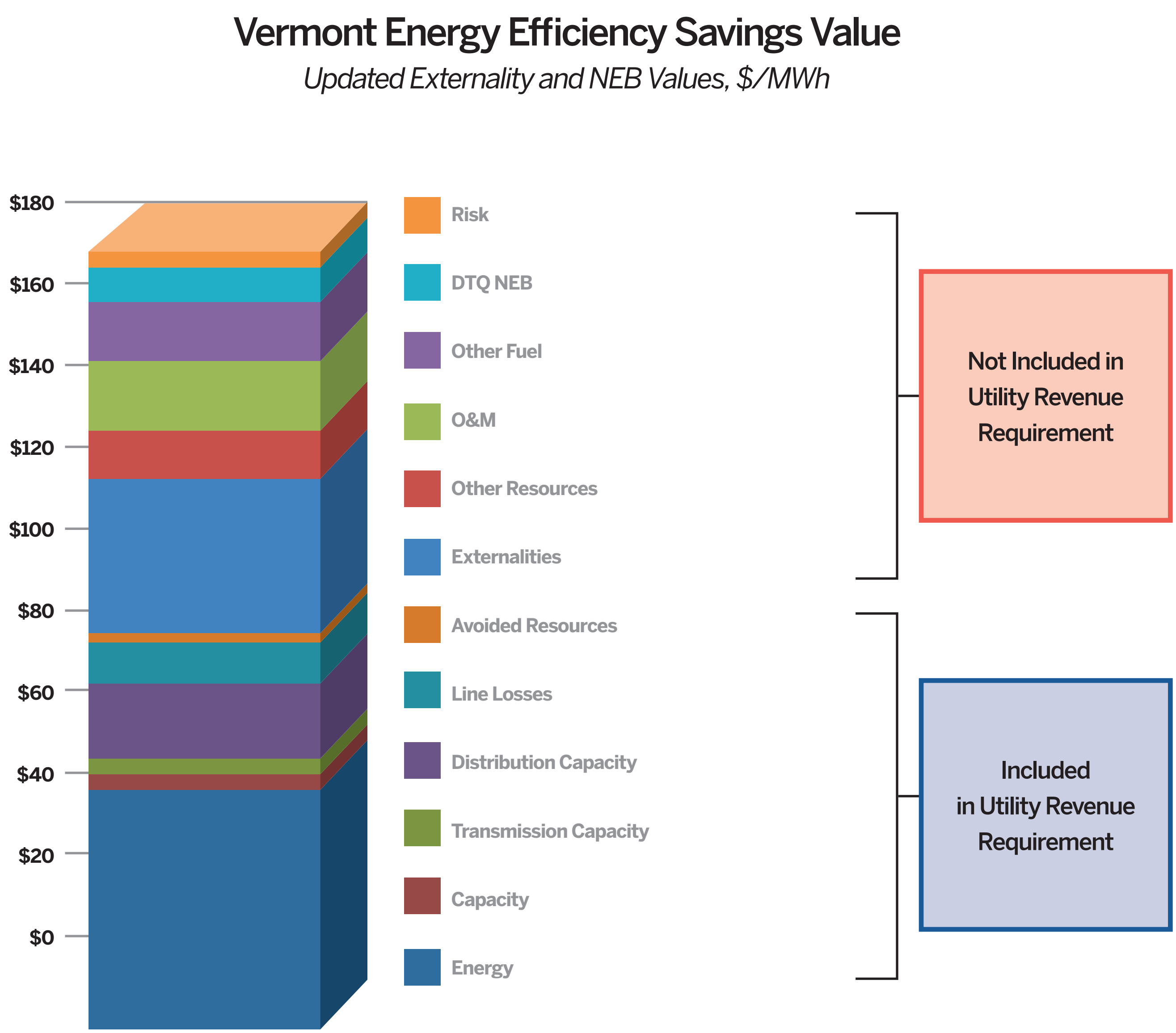
Table A-2. Potential Costs and Benefits (Value Streams) of Energy Efficiency

Benefit (or Cost)	Participant Test	RIM Test	PAC Test	TRC Test	Societal Cost Test
Energy Efficiency Program Costs					
Program Administration Costs (including EM&V)	—	X	X	X	X
EE Measure Costs: Program Incentives	—	X	X	X	X
EE Measure Costs: Participant Contribution	X	—	—	X	X
EE Measure Costs: Third-Party Contribution	—	—	—	X	X
Other EE Costs	X	—	X	X	X
Lost Revenues to the Utility	—	X	—	—	—
Utility System Benefits					
Avoided Production Capacity Costs	—	X	X	X	X
Avoided Production Energy Costs	—	X	X	X	X
Avoided Costs of Existing Environmental Regulations	—	X	X	X	X
Avoided Costs of Future Environmental Regulations	—	X	X	X	X
Avoided Transmission Capacity Costs	—	X	X	X	X
Avoided Distribution Capacity Costs	—	X	X	X	X
Avoided Line Losses	—	X	X	X	X
Avoided Reserves	—	X	X	X	X
Avoided Risk	—	X	X	X	X
Displacement of Renewable Resource Obligation	—	X	X	X	X
Reduced Credit and Collection Costs	—	X	X	X	X
Demand-Response Induced Price Effect (DRIPE)	—	X	X	X	X
Benefits To Participants					
Other Utility Benefits to Participants	X	—	—	X	X
Other Energy Savings (fuel oil, propane, natural gas)	X	—	—	X	X
Reduced Future Energy Bills	X	—	—	—	—
Other Resources Savings (septic, well pumping, etc.)	X	—	—	X	X
Non-Energy Benefits to Participants					
O&M Cost Savings	X	—	—	X	X
Participant Health Impacts	X	—	—	X	X
Employee Productivity	X	—	—	X	X
Property Values	X	—	—	—	—
Benefits Unique to Low-Income Consumers	X	—	—	—	X
Comfort	X	—	—	X	X
Other	X	—	—	X	X
Societal Non-Energy Benefits					
Air Quality Impacts	—	—	—	—	X
Water Quantity and Quality Impacts	—	X	X	X	X
Coal Ash Ponds and Coal Combustion Residuals	—	—	—	—	X
Employment Impacts	—	—	—	—	X
Economic Development	—	—	—	—	X
Other Economic Considerations	—	X	X	X	X
Societal Risk and Energy Security	—	—	—	—	X
Reduction of Effects of Termination of Service	—	X	X	X	X
Avoidance of Uncollectable Bills for Utilities	—	X	X	X	X

Source: Lazar and Colburn, 2013.

The RAP paper also cites an example from the State of Vermont of why it is important to consider all the value streams of energy efficiency. An evaluation of energy efficiency programs in Vermont concluded that avoided energy and capacity costs represented only about one-third of the total value of energy efficiency programs, as shown in Figure A-5.[127]\

Figure A-5. Example of the Relative Magnitude of Energy Efficiency Value Streams



Source: Lazar and Colburn, 2013. Created with assistance from Efficiency Vermont, based upon data from their annual reports and personal communications.

127 In the graphic, NEB stands for Non-Energy Benefits and DTQ for Difficult to Quantify. The value for "risk" derives from an attempt to quantify the economic value of reducing the risk for stranded investment in infrastructure. The value for externalities derives primarily from the avoided societal cost of carbon emissions.

Table A-3. Potential Benefits (Value Streams) of Demand Response

Benefit	Participant	RIM	PAC	TRC	Societal
Avoided Capacity Costs	—	Yes	Yes	Yes	Yes
Avoided Energy Costs	—	Yes	Yes	Yes	Yes
Avoided Transmission & Distribution Costs	—	Yes	Yes	Yes	Yes
Avoided Ancillary Service Costs	—	Yes	Yes	Yes	Yes
Revenues from Wholesale DR Programs	—	Yes	Yes	Yes	—
Market Price Suppression Effects	—	Yes	Yes	Yes	—
Avoided Environmental Compliance Costs	—	Yes	Yes	Yes	Yes
Avoided Environmental Externalities	—	—	—	—	Yes
Participant Bill Savings	Yes	—	—	—	—
Financial Incentive to Participate	Yes	—	—	—	—
Tax Credits	Yes	—	—		—
Other Benefits (e.g., market competitiveness, reduced price volatility, improved reliability)	Depends	Depends	Depends	Depends	Depends

Source: Woolf et al. (2013). *A Framework for Evaluating the Cost-Effectiveness of Demand Response*

D. Demand Response

The question of value streams has been similarly applied to DR, both generically and for specific states or utilities. For example, a 2013 report for the National Forum on the National Action Plan on Demand Response identified the value streams shown in Table A-3 and the C-E tests in which each should be included.[127]

It is also worth noting here that the nature of DR is changing because of the need to integrate ever-increasing amounts of variable renewable generation and EV charging. Historically, DR almost always came in the form of load curtailment and was almost always used as a peak shaving or emergency load-shedding resource when demand was approaching system capacity limits. Today, flexible load is becoming as important as load curtailment in areas with high wind, PV, and EV penetration. In a groundbreaking 2017 report on DR potential for the California PUC, LBNL proposed a new taxonomy based on four core categories of services that DR resources can provide: load shaping, shifting, shedding, and shimmying.

- "Shape" captures DR that reshapes customer load profiles through price response or on behavioral campaigns — "load-modifying DR" — with advance notice of months to days.
- "Shift" represents DR that encourages the movement of energy consumption from times of high demand to times of day when there is a surplus of renewable generation. Shift could smooth net load ramps associated with daily patterns of solar energy generation.
- "Shed" describes loads that can be curtailed to provide peak capacity and support the system in emergency or contingency events — at the statewide level, in local areas of high load, and on the distribution system, with a range in dispatch advance notice times.
- "Shimmy" involves using loads to dynamically adjust demand on the system to alleviate short-run ramps and disturbances at timescales ranging from seconds up to an hour.[129]

The LBNL potential study modeled multiple value streams

128 Woolf, T., Malone, E., Schwartz, L., and Shenot, J. (2013). *A Framework for Evaluating the Cost-Effectiveness of Demand Response.* Prepared for the National Forum on the National Action Plan on Demand Response: Cost-Effectiveness Working Group. Retrieved from https://emp.lbl.gov/publications/framework-evaluating-cost

for these four categories of DR services and discovered that "shift" resources are in greater need in California (and are thus more valuable) than "shed" resources. In fact, LBNL found that "conventional system-wide peak shed DR is unlikely to provide significant value to the grid in the future." According to LBNL, the secret to unlocking DR value turns out to be a "portfolio" approach — that is, managing DR resources in such a way that they can capture multiple value streams for customers, local utilities, and CAISO.

The list of resources that can provide "shape, shift, and shimmy" services goes well beyond the list of resources that have traditionally provided load-shedding DR (industrial processes and residential air conditioners, primarily). Controllable, grid-integrated, electric water heating and space heating appliances are but two examples of what is increasingly seen as a huge, untapped reservoir of DR potential.[130] Energy storage devices, potentially including the batteries in EVs, can also provide these services.

E. Electric Vehicles

Many of the organizations that have adopted formal definitions of DER to date have excluded or not specifically included EVs in those definitions. Perhaps for this reason, the literature on value streams associated with EVs is at this time quite limited. This is likely to change in the future, as some jurisdictions have already adopted DER definitions that specifically include EVs.

The value streams associated with EVs depend on whether the customer practices uncontrolled or smart charging and whether the EV can deliver power from its battery to other behind-the-meter energy uses or inject power to the grid (the latter being known as vehicle-to-grid or V2G technology).

When we speak of smart charging, we refer to instances where the customer operates their EV charging system as a flexible load. Instead of charging the EV as soon as the need arises and as fast as possible, these customers make decisions about when to charge based at least in part on TOU or real-time power costs. Simple decisions can be made manually by the customer, such as charging during off-peak periods under a TOU rate design. Alternatively, the customer can pre-program choices about when to charge using smart technology inside the charging system or the vehicle. Smart charging algorithms could potentially even vary the amount of power drawn by the battery from moment to moment, in response to a signal from the customer's utility or an ISO, such that the EV provides ancillary services. With smart charging, an EV thus can offer value streams that combine some of the benefits of DR with those of a battery energy storage system.

With V2G capability, EVs can draw power from the battery and inject it into the grid when it is useful and valuable to do so. To date, V2G capability has been almost entirely an experimental proposition and significant practical barriers to this practice remain.[131]

RMI once again looked at participant and utility system value streams, this time for EVs with smart charging and V2G capability, in a 2016 paper.[132] Figure A-6, excerpted from that RMI report, indicates the services and value streams that can flow to different parties when EVs with smart charging capability (but not V2G capability) are controlled by an aggregator.

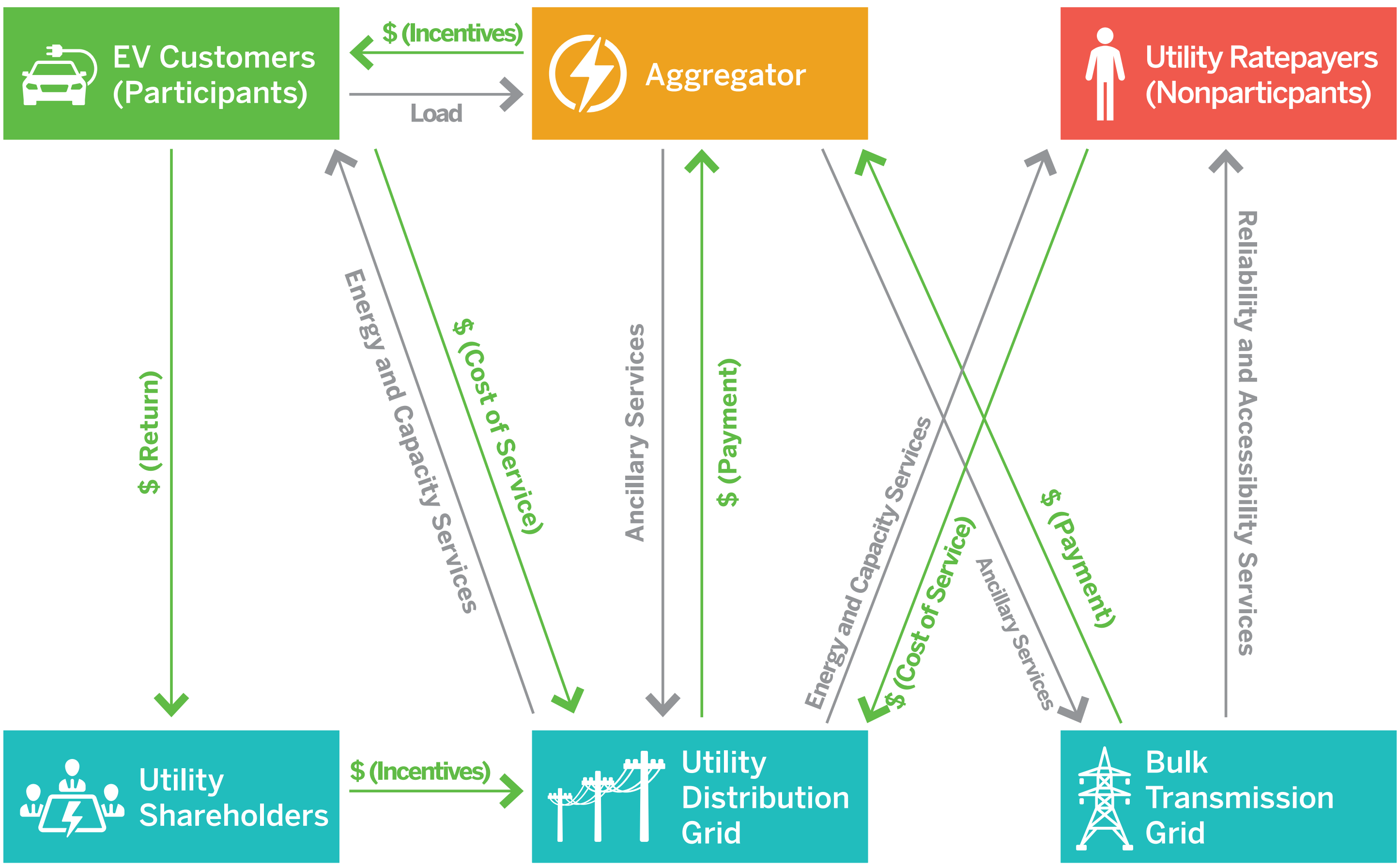
129 Alstone, P., et al. (2017). *Final Report on Phase 2 Results: 2025 California Demand Response Potential Study - Charting California's Demand Response Future.* Lawrence Berkeley National Laboratory for CPUC. Retrieved from http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452698

130 Some jurisdictions may treat controllable water heating and space heating as a form of energy storage rather than DR. The rationale is that these appliances can "store" electric energy by preheating water or buildings so less electric energy is needed to heat them later. The value streams of these flexible loads are the same regardless of how they are categorized.

131 Some of the barriers are described in Hutton, M., and Hutton, T. (2012). Legal and Regulatory Impediments to Vehicle-to-Grid Aggregation. 36 Wm. & Mary Envtl. L. & Pol'y Rev. 337. Retrieved from https://scholarship.law.wm.edu/wmelpr/vol36/iss2/3

132 Gold, R., and Goldenberg, C. (2016). *Driving Integration: Regulatory Responses to Electric Vehicle Growth.* Rocky Mountain Institute. https://www.rmi.org/insights/reports/driving-integration/

Figure A-6. Potential Services (Value Streams) of Electric Vehicles With Smart Charging Capability



Source: Gold and Goldenberg. (2016). *Driving Integration: Regulatory Responses to Electric Vehicle Growth*

Finally, Table A-4 on the next page, based on the authors' judgment and the RMI paper, the value streams that can potentially be provided by EVs depending on whether smart charging and V2G capabilities are used. Note that in this table, we compare the impacts of replacing fossil-fueled vehicles with EVs. From this perspective, EVs always add incremental load to the utility system, and thus add to utility system energy costs, and may also add to capacity costs depending on how they are charged.[133] EVs with smart charging *may* be able to provide some ancillary services that can *reduce* utility system costs, for example frequency response services. They will also reduce participant costs on gasoline or diesel fuel. With V2G capability, EVs can potentially provide a much broader set of potential value streams.

133 If EV load can be accommodated without increasing generation, transmission, and distribution capacity, retail energy *rates* could potentially decline even as total utility system energy *costs* increase, because capacity costs would be spread out over more kWh of sales. This is important to consider if a ratepayer perspective to C-E is examined.

Table A-4. Potential EV Value Streams

Beneficiary	Value Streams	Uncontrolled Charging	Smart Charging	Smart Charging With V2G
Utility System	Avoided energy costs			✔
	Avoided generation capacity costs			✔
	Avoided reserves or other ancillary services		✔	✔
	Avoided transmission and distribution system investment			✔
	Avoided transmission and distribution line losses			✔
	Avoided operations and maintenance costs			✔
	Wholesale market price suppression			✔
	Avoided renewable (or electricity) portfolio standard compliance costs			✔
	Avoided environmental compliance costs			✔
Participants	Electricity bill savings, credits, or revenues			✔
	Participant resource savings (motor vehicle fuel)	✔	✔	✔
	Increased resilience			✔
Public	Public health benefits	✔	✔	✔
	Energy security	✔	✔	✔
	Jobs and economic development benefits	✔	✔	✔
Environment	Environmental benefits	✔	✔	✔

Source: Author analysis

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Regulatory Assistance Project (RAP)®

50 State Street, Suite 3
Montpelier, Vermont
USA

802-223-8199
raponline.org