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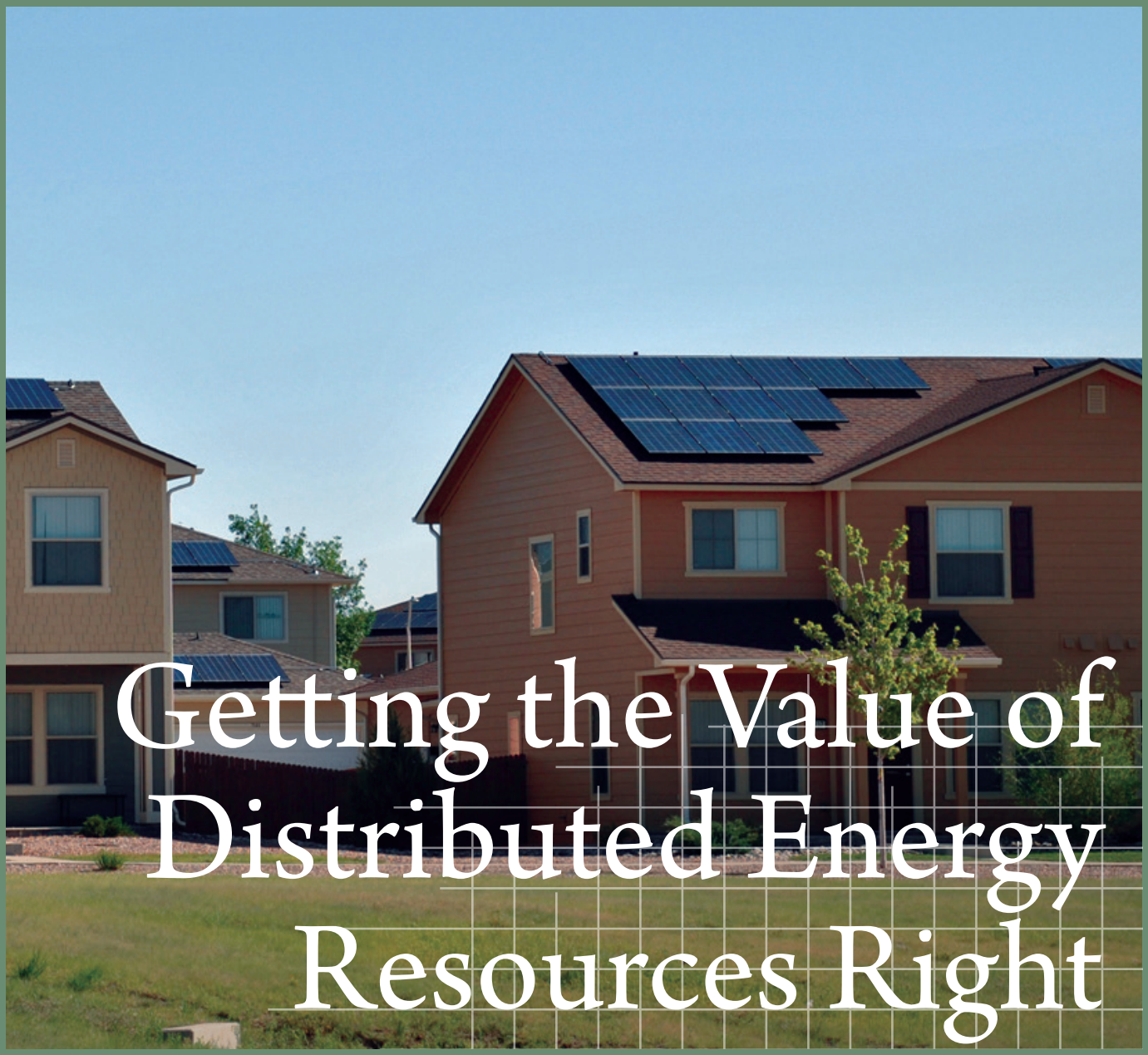

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Getting the Value of Distributed Energy Resources Right

Using a Societal Value Stack

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Table of Contents

Executive Summary

Distributed energy resources (DERs) are small assets that can reduce or supply some or all onsite demand for electricity. Some DERs, such as solar photovoltaic (PV) systems and combined heat and power (CHP) facilities, generate electricity. Others, such as energy storage and demand response resources, do not generate electricity themselves but can modify or reduce customers' electricity demand. DERs' presence has grown over the past decade, and their proliferation is sure to continue.

DERs' growing prevalence increases the pressure on state legislatures and public utility commissions to resolve disputes over how DERs should be compensated for providing services valued by utilities and their customers. The most contentious of these disputes relates to compensating DERs like solar PV and energy storage for the electricity that they export to the grid. Currently, 40 states use net energy metering (NEM) programs to compensate electricity exports from DERs. NEM credits DER owners for their exported excess generation against their consumption of electricity from centralized resources, based on the underlying retail rate. That rate is usually time-invariant and uniform across a utility's service territory. As a result, NEM-based compensation does not capture differences in the value of DERs across time or location. Diverse concerns over how NEM allocates the benefits and costs of DERs have led many states to examine their NEM programs, and in some cases to revise or abandon them.

This report analyzes a promising alternative to NEM, "value stacking." It describes the sources of value added by DERs and recommends adopting an approach to DER compensation that is inclusive of those values. Once DERs' presence in a given utility service territory has become significant, value stacking is preferable to other alternatives, because it:

- Compensates all DERs for the services they provide, using uniform criteria and based on measured performance;
- Reflects differences across times (e.g., "peak" versus "off-peak" demand) and locations (e.g., where congestion is absent versus where it makes it relatively expensive to deliver electricity services from the centralized grid);
- Recognizes the costs of emitting greenhouse gases and local pollutants and compensates DERs for avoiding them;
- Relies on a uniform, accurate compensation scheme to inform where DERs are installed and operated (instead of prescribing volumes or locations of DER capacity); and
- Is neutral with respect to technology and scale.

In addition to explaining the benefits of this value stacking methodology, the report also provides suggestions for how to implement this approach.

Introduction

Distributed energy resources (DERs) are small physical assets that can reduce or supply some or all onsite electricity demand ("load"). They tend to be located "behind the meter," meaning that they are owned and operated by electricity customers rather than utilities.[1] Some, but not all, types of DERs generate electricity; those that can do so, such as solar photovoltaic (PV) systems and combined heat and power (CHP) facilities, are called distributed generation (DG). Other types of DERs, such as energy storage and demand response resources, can modify or reduce customers' electricity demand, even though they do not generate electricity themselves. DERs' presence in the United States has been growing, and there is little reason to doubt that DERs will eventually become a standard feature of electricity systems nationwide.[2]

DERs can provide many services to the grid. For example, PV systems can reduce customers' need for electricity from the grid as well as inject electricity into the grid. Energy storage systems can modify customers' electricity demand throughout the day, reduce their peak demand, and help with system balancing. Currently, different types of DERs receive compensation through a variety of programs and mechanisms, some market-based, others regulatory. Demand response resources, for instance, can participate in wholesale or retail electricity markets in most states, individually or in aggregations.[3] Solar PV owners most often receive bill credits for the electricity they generate and export to the electricity grid. And the purchase and installation of energy-efficient assets can often be financed through utility- or third-party vendor-sponsored programs and property-assessed clean energy or "PACE" programs.

Today, as DERs are becoming more common, state legislatures and public utility commissions are wrestling with the question of how best to compensate them for providing these electricity services.[4] At present, the most contentious policy debates focus on how to compensate DERs that are capable of exporting electricity to the centralized grid, such as DG and some forms of energy storage.

Net energy metering (NEM) has been the predominant approach to compensating owners of DG. As of April 2019, 40 states, plus DC and four territories, use some form of mandatory NEM to assign a value to electricity that DERs inject into the grid.[5] Under NEM, generation in excess of what customers consume onsite is exported to the electricity grid

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[1] In a 2016 report, the National Association of Regulatory Utility Commissioners (NARUC) collected definitions used by several states and other authorities before suggesting the following definition:

> A DER is a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load.

NARUC, Distributed Energy Resources Rate Design and Compensation 43-44 (2016), https://perma.cc/37A5-D5S6.

[2] *See generally* Ignacio J. Perez-Arriaga et al., Utility of the Future: An MIT Energy Initiative Response to an Industry in Transition 36 (2016), https://perma.cc/56VC-H8EN.

[3] "Aggregation" involves the coordination of multiple, dispersed DERs, and is usually conducted by an entity that also acts as a liaison between the DER owners and a buyer of the aggregated service they provide. DERs can interact with the bulk power system through an aggregator, usually a distribution utility or a third-party who bids the aggregated service offering into a wholesale market. *See* Scott Burger et al., *A review of the value of aggregators in electricity systems*, 77 Renewable & Sustainable Energy Revs. 395 (2017) (describing role and functions of aggregators).

[4] North Carolina Clean Energy Technology Center, The 50 States of Solar: Q1 2019 Quarterly Report Executive Summary (2019), https://perma.cc/PCR7-RC7P (cataloguing regulatory proceedings related to distributed solar in 43 states, DC, and Puerto Rico); *see also* Tom Stanton, Nat'l Reg'y Research Inst., Review of State Net Energy Metering and Successor Rate Designs (2019), https://perma.cc/2XCF-TQX8 (surveying recent and ongoing efforts).

[5] DSIRE/NC Clean Energy Ctr., Net Metering—April 2019 (2019), https://perma.cc/GLM4-9F87.

where it is distributed to other retail electricity consumers. DER owners are generally credited for this excess generation against their consumption for each billing period.[6] That is, under NEM, both excess generation and retail electricity service are valued at the same rate, based on the underlying retail rate that the customer faces.

States initially adopted NEM in large part because it was a simple mechanism that allowed customers to install and own DERs capable of injecting excess generation into the grid. It required no upgrades to electric meters, few if any changes to how utilities conducted billing, and no change to the legal status of DER owners even though they exported electricity to the grid. As a result, NEM allowed for DER integration without disrupting the rules or relationships that governed electricity service. NEM programs fostered growth in DERs, especially distributed solar PV.[7] As participation has grown, however, problems with NEM have become increasingly evident. First and foremost among those problems is that, because NEM is based on retail rates, whenever retail rates fail to reflect the costs of electricity service accurately, NEM likewise inaccurately values DERs.[8] This means, for instance, that NEM often *undercompensates* DERs for avoiding emissions of greenhouse gases and local pollutants.[9] And, in general, NEM does a poor job of guiding developers and would-be DER owners to put the right sort of DER in the right place, resulting in economically inefficient patterns of development.

A second, related problem is how NEM allocates the costs and benefits of DER owners' participation in the electricity grid. Specifically, utilities and others have argued that, under NEM, DER owners pay too little towards the cost providing access to reliable grid electricity when they get bill credits. The costs of DER owners' access are thus—so the argument goes—borne by other electricity consumers, who pay more to help make up the difference,[10] and by utilities that absorb the rest of the shortfall. Casting these cost allocations as misallocations leads to the conclusion that NEM runs afoul of core regulatory principles like cost causation.[11]

Concerns about NEM and responses to those concerns vary markedly across states. Reform efforts in California, Hawaii, and New York, for instance, aim to support DERs' further proliferation but ensure that it is cost-effective. Meanwhile, in Indiana, Kentucky, and Louisiana, reforms aim primarily to curb DERs' impacts on utility cost recovery. And in New Hampshire, Nevada, and Vermont, reforms aim to strike a balance between encouraging continued DER adoption while also curbing DERs' effects on utility cost recovery.

This report recommends that state policymakers, as they grapple with how to integrate DERs effectively, make two changes to their regulatory approaches to DER integration. First, any approach to DER compensation should be centered

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[6] Some states' programs now require customers to pay a "non-bypassable" charge or "minimum bill" that cannot be offset by credits for excess generation. *See* Stanton, note 4, at 23. Many programs also include provisions that allow customers to carry over excess credits across billing periods. *See, e.g.*, NV Energy, https://www.nvenergy.com/account-services/energy-pricing-plans/net-metering/net-metering-faqs (accessed Nov. 15, 2019).

[7] Stephen Comello & Stefan Reichelstein, *Cost Competitiveness of Residential Solar PV: The Impact of Net Metering Restrictions*, 75 Renewable & Sustainable Energy Revs. 46, 46, 54 (2017).

[8] *See* Richard L. Revesz & Burcin Unel, *Managing the Future of the Electricity Grid: Distributed Generation and Net Metering*, 44 Harv. Envtl. L. Rev. 43, 71-77 (2017), https://policyintegrity.org/files/publications/Managing_the_Future_of_the_Electricity_Grid.pdf.

[9] Steven Sexton et al., *Heterogeneous Environmental and Grid Benefits from Rooftop Solar and the Costs of Inefficient Siting Decisions* 19 (Nat'l Bureau of Econ. Research, Working Paper No. 25241, 2018), https://perma.cc/TK7G-YPQ2 ("...more than 25 percent of states provide subsidies that are at least $0.05 per kWh less than avoided damages.").

[10] The term "cost shift" describes when costs incurred to serve one group of customers are paid, in part or in full, by another. Cost shift represents a departure from the regulatory principle of "cost causation," which holds that a customer should pay the costs incurred to provide that customer with benefits.

[11] *See, e.g.*, Sanem Sergici et al., *Quantifying Net Energy Metering Subsidies*, 32 Electricity J. 106632 (2019), https://doi.org/10.1016/j.tej.2019.106632 ("… NEM policies create a subsidy issue from non-DG customers to DG customers."); Willis Geffert & Kurt Strunk, *Beyond Net Metering: A Model for Pricing Services Provided by and to Distributed Generation Owners*, 30 Electricity J. 36, 37 (2017).

on a "value stack" framework that reflects diverse, time- and location-specific value categories. Second, the scope of these value categories should be consistent with the perspective of society as a whole, not just a utility or its ratepayers.

It is important to note, however, that these recommendations still represent a second-best alternative to rate design reforms that cause electricity prices to more accurately reflect the costs of providing electricity services. In particular, if rates reflected accurate costs—including those related to emissions—based on time and location, consumers could respond by changing their patterns of consumption and DER adoption and use in a socially efficient manner.[12]

Before fully explaining these recommendations, part I of this report offers some background about the electricity grid and its regulation to provide context, and part II describes the benefits of DER deployment. Part III begins by describing the origins and effects of NEM and the problems that result from using it to compensate DERs. It then explains how a value stack framework can translate multiple, time-and-location-specific inputs into a rate of DER compensation, with inputs reflecting DERs' full value to society rather than merely the perspective of a utility or electricity consumers. The last part offers some conclusions.

[12] *See generally* Richard L. Revesz & Burcin Unel, *Managing the Future of the Electricity Grid: Modernizing Rate Design*, 44 Harv. Envtl. L. Rev. (forthcoming 2020), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3373163.

I. Background

To comprehend the value provided by DERs, one must understand the components of the centralized electricity grid as well as what DERs are and what they can do.

The electricity grid's main components

The centralized electricity grid is made up of several parts. (See Figure 1.) The bulk power system encompasses large-scale generators and transmission facilities. Large generators are usually located some distance away from those who ultimately consume electricity. Transmission lines carry electricity at high voltage across most of that distance. Distribution lines carry it the rest of the way at lower voltage. The bulk power and distribution segments of the grid interact, but they are managed mostly independently of one another, such that the real-time balance of electricity generation and consumption effectively happens at two levels. Grid managers at each level have limited access to detailed, real-time information about operations on the other level.

Figure 1. Segments of the electricity grid and where DERs can interconnect to it.

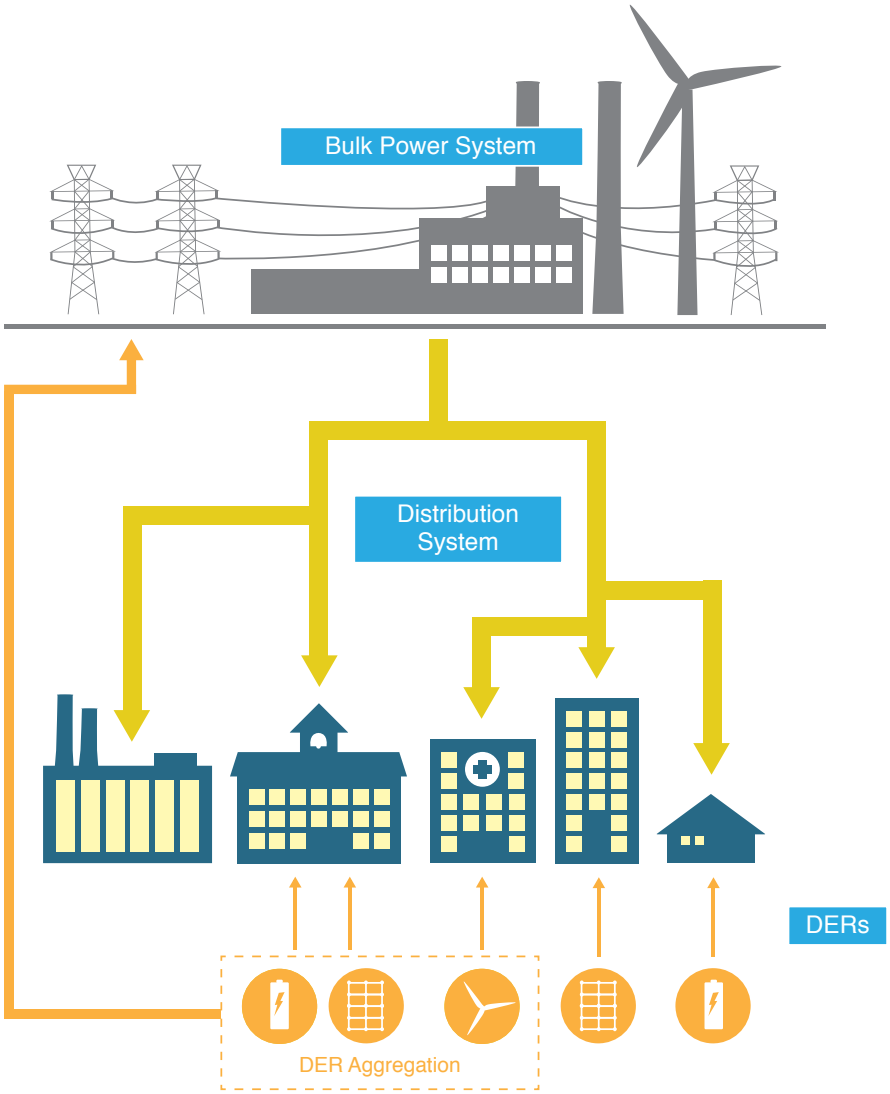

Figure 1 shows a simplified rendering of the electricity grid. Most generation and all transmission occurs in the bulk power system (above the line); electricity flows from there through the distribution system to customers (below the line). DERs generally interconnect to the distribution segment of the system, but can also participate in the bulk power system in aggregations. Where distribution grids have integrated both DERs and "smart" components, two-way flows of electricity and information have converted a once-centralized grid into a partly decentralized one.[13]

Distributed energy resources: a brief taxonomy

There are several subcategories of DERs, which are each comprised of a variety of physical devices and techniques (sometimes enabled by software and communications technology). Table 1 illustrates this point.

Table 1. DER subcategories and examples.[14]

Subcategory	Examples
Distributed generation	• solar PV • small-scale wind • CHP • fuel cell • microturbine • small reciprocating engine
Energy storage	• chemical batteries (lithium-ion, nickel-cadmium, flow, others) • battery-powered electric vehicles • chilled water heating/cooling systems
Demand response	• curtailable residential water heaters and pool pumps • appliances and programmable thermostats that respond to signals from the grid • building energy management systems
Energy efficiency	• LED lighting • improved building envelope insulation • improved seals on doors and windows • high-efficiency equipment and appliances

Although Table 1 lists particular assets or techniques separately, several of them can be deployed in combination.[15] Solar PV plus battery storage, for instance, is an increasingly popular combination. The combination ensures that the storage component is charged using a renewable primary energy source and that the owner will have access to electricity generated by the solar PV system even at times when the sun is not shining.

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[13] *See* Jeffrey J. Cook et al. Expanding PV Value: Lessons Learned from Utility-led Distributed Energy Resource Aggregation in the United States (2018), https://perma.cc/3FCP-3XYH (describing efforts by 23 utilities to coordinate the operation of DER in their service territories so that they can perform ancillary services and enhance reliability).

[14] The assets and techniques listed are not exhaustive. For a more complete list, see Lisa Schwartz et al., Lawrence Berkeley Nat'l Lab., Electricity End Uses, Energy Efficiency, and Distributed Energy Resources Baseline: Distributed Energy Resources, ch. 1 (2017), https://perma.cc/9LJY-L2VY. Table 1 also does not list all DER examples for each subcategory, and it omits large-scale energy storage and demand response assets, which tend to either be owned by commercial and industrial facilities or to be located in front of the meter, where they serve the bulk power system.

[15] *See generally* John Shenot et al., Capturing More Value from Combinations of PV and Other Distributed Energy Resources (2019), https://perma.cc/P63S-TGQR.

DERs differ in their ability to perform different services that are required for electricity system operation.[16] For example, solar PV can export electricity to the grid, while demand response can only reduce net load or modify load shapes. However, distributed solar PV cannot provide "black start" capability to restore service after an outage, but CHP and storage can.[17] DER profiles also vary with respect to how, how much, and for how long, they can perform some of those functions.[18]

Table 2. Potential functions of DERs.

Function	Type of DER					
	Solar PV*	Solar PV + Storage	Standalone Storage	CHP	Demand Response	Energy Efficiency
Generation	Yes, limited	Yes, limited	No	Yes	No	No
Generation capacity	Yes, limited	Yes, limited	No	Yes	Yes	Yes, limited
Voltage control	No	Yes	Yes	Yes	No	No**
Frequency regulation	No	Yes	Yes	Yes	Yes, limited	No
Spinning reserves	No	Yes	Yes	Yes	Yes, limited	No
Nonspinning reserves	No	Yes	Yes	Yes	No	No***
Flexibility to support renewables integration	No	Yes	Yes	Yes	Yes	No
Line loss reduction	Yes	Yes	Yes, limited	Yes	Yes	No**
Black start capability	No	No	Yes	Yes	No	No

** Newer inverters enable solar PV modules to perform a wider range of functions than those deployed even a few years ago. As new modules' prevalence grows, some of the "No" entries in this column—such as "Flexibility to support renewables integration"—will switch to "Yes."*
*** Conservation voltage reduction (CVR) is an exceptional form of energy efficiency that can provide voltage control and reduce line losses.*
**** A small subset of energy efficiency resources can bid to provide services in wholesale capacity markets.*

It is important to note that while Table 2 indicates various DERs' inherent abilities, DERs' ability to perform functions cost-effectively—or at all—also depends in part on the location and design of supporting infrastructure.[19]

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[16] The Smart Electric Power Alliance recently assembled a bibliography of reports that discuss the functions DER can perform. It indicates which reports focus on which categories of electricity service. Tanuj Deora et al., Smart Elec. Power Alliance, Beyond the Meter: Recommended Reading for a Modern Grid 12 tbl.4 (2017).

[17] John Larsen & Whitney Herndon, Rhodium Grp. (prepared for U.S. Dep't of Energy), What Is It Worth? The State of the Art in Valuing Distributed Energy Resources 11 (2017), https://perma.cc/KQ96-3C9U.

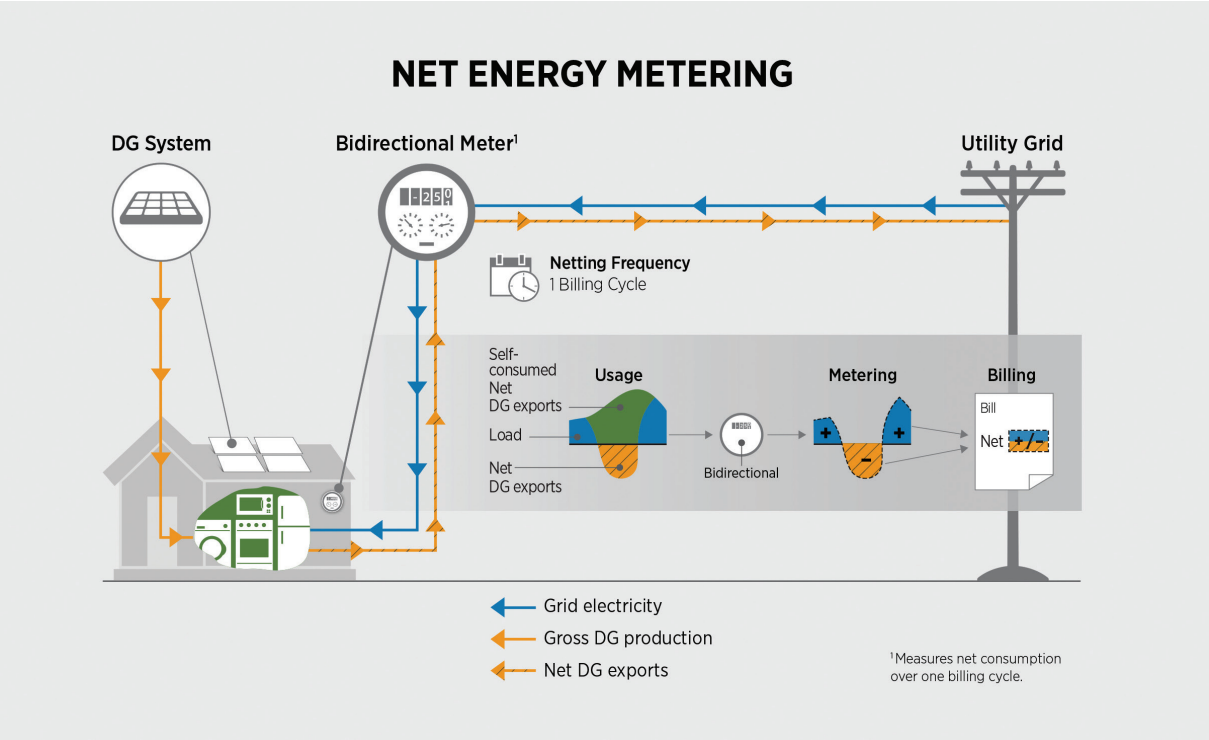
[18] Ryan Edge et al., Smart Elec. Power Alliance, Distributed Energy Resources Capabilities Guide 6 (2016).

[19] *See* San Diego Gas & Elec. Co., Distribution Resources Plan; Demonstration Project A: Enhanced Integration Capacity Analysis 30 fig.16 (2016), https://perma.cc/HJ44-UBJ8 (describing differences in solar PV, battery, and electric vehicle profiles under different circumstances).

Net energy metering

NEM programs vary in their particulars,[20] but the generic version of NEM is broadly representative. It involves a utility customer that has (1) an onsite DER capable of generating electricity, and (2) a single electricity meter. Essentially, when customers draw electricity from the grid, the meter runs forward, and when customers generate more than they consume, the excess flows to the grid and the meter runs backward.[21] Utilities charge customers at the retail rate, a volumetric, or per kilowatt-hour (kWh) charge, for their net consumption of electricity. This arrangement credits customers through their electricity bill for their excess generation. Notably, if electricity generated by DERs only reduces customers' net consumption from the grid without any excess flows, the arrangement resembles the adoption of energy efficiency measures that reduce electricity demand. The National Renewable Energy Laboratory developed Figure 2 to summarize NEM visually.

Figure 2. National Renewable Energy Laboratory's schematic of NEM, showing physical and financial interaction between DER owner and utility.[22]



[20] For a survey of current NEM programs, see the "Programs" webpage of NC Clean Energy Technology Center's Database of State Incentives for Renewables & Efficiency, https://programs.dsireusa.org/system/program.

[21] Older, analog meters literally spin in reverse; newer metering technology, called advanced metering infrastructure or AMI, is digital and can track flows in both directions. *See* Qie Sun et al., *A Comprehensive Review of Smart Energy Meters in Intelligent Energy Networks*, 3 IEEE Internet of Things J. 464, 465-67 (2016). By 2018, 53% of electricity customers had AMI installed. U.S. Energy Info. Admin., Form EIA-861 (2018), Spreadsheet labeled "Advanced_Meters_2018," https://www.eia.gov/electricity/data/eia861/zip/f8612018.zip. This was up from 4.7% in 2008 and 37.6% in 2013. Fed. Energy Reg'y Comm'n, 2018 Assessment of Demand Response and Advanced Metering—Staff Report 3 tbl.2.1 (2018).

[22] Owen Zinaman et al., Nat'l Renewable Energy Lab., Grid-Connected Distributed Generation: Compensation Mechanism Basics 3 (2017), https://perma.cc/L9CB-Z8TL.

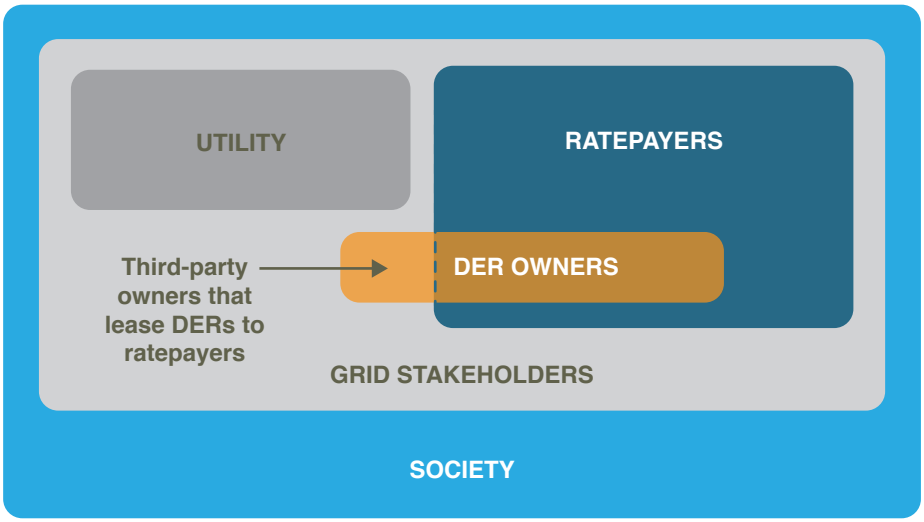
II. The value of distributed energy resources

Whether by reducing a customer's need to buy electricity from the grid, exporting excess electricity from that customer to the grid, or performing some other function listed in Table 2 above, DERs can reduce the need for operation of one or more components of the centralized grid. Assessing the value of DERs requires identifying these benefits and costs, then measuring those benefits and costs in comparison to the benefits and costs of the centralized resources that DERs would displace. As explained below, the first of these steps involves adopting one or more analytical perspectives. And the subsequent steps involve specifying where, when, and how the DERs being analyzed would operate, as well as a baseline scenario to which their operations can be compared.

Adopting the right perspective(s)

The state agencies charged with regulating electric utilities require estimates of a given investment's costs and benefits before authorizing utilities to pay for it using ratepayers' money. But because the economic value of the assets and systems that contribute to electricity service provision accrues differently to different stakeholders, deriving an estimate of that value requires adopting the perspective of one or more stakeholders. Figure 3 shows the overlapping perspectives of stakeholders affected by decisions to install and operate electricity resources, whether distributed or centralized. The perspective chosen determines three key aspects of valuation: (1) the scope of effects to be counted in the analysis, (2) whether to count them as benefits or costs, and (3) to whom and how much those benefits and costs accrue.

Figure 3. Overlapping perspectives on electricity-related benefits and costs.



Public utility regulatory commissions recognize the importance of perspective in at least some contexts—most often in relation to energy efficiency programs—and require utilities to employ one or more tests that embody prescribed perspectives when proposing to recover particular costs.[23] The five tests that were initially developed by California's Energy

[23] *See* Nat'l Efficiency Screening Project, Database of State Efficiency Screening Practices, https://nationalefficiencyscreening.org/state-database-dsesp/ (accessed Oct. 20, 2019) (indicating tests prescribed in 46 states and the District of Columbia).

Commission and Public Utilities Commission in 1983,[24] and later adopted elsewhere, are summarized in Table 3 below. The entries in the "perspective" column indicate the scope of benefits and costs to be considered when implementing the corresponding test. The Participant Cost Test provides the perspective with the narrowest scope and the Societal Cost Test the broadest, with the others arrayed in between. Crucially, of those listed in table 3, only the societal perspective takes the costs of emissions—and the benefits of avoiding emissions—into account.

Table 3. Perspectives associated with tests of DER benefits and costs.

Perspective	Test
Society as a whole	Societal Cost
Utility system + customers participating in one or more sanctioned programs	Total Resource Cost
Utility system	Utility Cost
Impact on rates paid by all electricity customers	Rate Impact Measure
Customers who participate in a given program, e.g., NEM	Participant Cost

Many states direct utilities to use at least two of these perspectives when analyzing the value of energy efficiency investments,[25] in order to discern both the magnitude and distribution of those investments' benefits and costs. California and New York direct their utilities also to do so for DER compensation. Specifically, California's Public Utilities Commission recently updated its directive to utilities regarding cost-effectiveness analyses, instructing them to make the Societal Cost Test the primary analytic screen and also to apply, secondarily, the Total Resource Cost Test and Ratepayer Impact Measure to all DERs and supply-side resources.[26] And in New York, a 2016 Public Service Commission Order directs utilities to employ a standard benefit cost test, complete with societal, utility, and ratepayer perspectives, to assess the value of proposed DER procurements and energy efficiency projects. [27]

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[24] *See generally* Cal. Pub. Utils. Comm'n, Standard Practice for Cost-benefit Analysis of Conservation and Load Management Programs: Joint Staff Report (1983).

[25] *See* Nat'l Efficiency Screening Project Database, *supra* note 23 (listing analytic perspectives prescribed for use by utilities in numerous states, including California, Minnesota, and New York). The National Energy Efficiency Screening Project, recognizing that jurisdictions vary in their policy objectives and treatment of particular costs and benefits as relevant, has developed a framework that regulators can use to develop a jurisdictionally specific Resource Value Test for identifying and estimating benefits and costs of investments in energy efficiency. Nat'l Efficiency Screening Project, The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening (2014), https://perma.cc/TQG6-9KBP. They plan to publish a manual in June 2020 on how to apply that framework to DERs. Nat'l Efficiency Screening Project, National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (NSPM for DERs)—Overview 3 (2019), https://perma.cc/ZG3A-CQ9E.

[26] Decision adopting cost-effectiveness analysis framework policies for all distributed energy resources, Cal. Pub. Utils. Comm'n, RM 14-10-003, at 2, 65-67 (May 21, 2019), https://perma.cc/L73F-KPNX.

[27] Order Establishing the Benefit Cost Analysis Framework, N.Y. Pub. Serv. Comm'n, Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision 1-2 (Jan. 21, 2016), https://perma.cc/9UQD-3PQA.

Distributed energy resources' benefits and costs

Numerous reports already identify and categorize benefits and costs of DERs.[28] Tables 4 and 5 organize a conventional list of those benefits and costs using the perspectives described above. Note that these tables contain illustrative lists—not comprehensive or definitive ones[29]—of potential benefits and costs.

Table 4. Potential Benefits of DERs.

Perspective	Category	Benefit
Electricity system stakeholders (i.e., utilities and their customers, including DER owners)	Bulk power system	Avoided energy costs
		Avoided generation capacity costs
		Avoided reserves and ancillary services costs
		Avoided transmission capital costs and line loss
		Avoided financial risk of primary energy source price volatility
		Avoided environmental compliance costs
	Distribution system	Avoided distribution capital costs and line losses
Society	Public health and safety	Improved resilience to disruptive hazards and stressors
		Public health benefits of avoided local pollution
	Environmental	Environmental benefits of avoided local pollution
		Avoided greenhouse gas emissions

As Table 4 shows, by avoiding the need to incur various costs, DERs can yield diverse benefits to centralized electricity system stakeholders. And, by avoiding emissions and improving electricity system resilience, they can also benefit society as a whole. Compared with these benefits, the costs of DERs, listed in Table 5 below, tend to be easier to measure. Capital and maintenance costs for a DER owner and interconnection costs for the local utility, for instance, which are available from accounting records, do not require estimation.

[28] *See, e.g.*, Shay Bahramirad, *Intro to Value of DER*, Presentation to NextGrid Working Group 1 (Feb. 28, 2018), https://perma.cc/Z44Q-XRSL; Galen Barbose, Lawrence Berkeley Nat'l Lab., Putting the Potential Impacts of Distributed Solar into Context 12 tbl.2 (2017), https://perma.cc/WLP3-2J2P; Susan F. Tierney, The Analysis Grp., The Value of "DER" to "D": The Role of Distributed Energy Resources in Supporting Local Electric Distribution System Reliability (2016), https://perma.cc/36ND-XDR9.

[29] Other potential benefits not listed here include, for instance, lower bills for low-income electricity consumers and reduced adverse emissions impacts for environmental justice communities. Gridworks et al., The Role of Distributed Energy Resources in New Jersey's Clean Energy Transition 4, 9 (2019), https://perma.cc/7MMU-7Y6Z; Tim Woolf et al., Synapse Energy Econ. (prepared for Advanced Energy Econ. Inst.), Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for All Relevant Costs and Benefits 30-31 (2014), https://perma.cc/5LQ3-Q437.

Table 5. Costs of DERs.

Perspective	Category	Costs
Utilities + ratepayers who do not own DERs	Program costs	Measure costs (to utility)
		Financial incentives
		Program and administrative costs
		Evaluation, measurement, and verification
	Integration	Interconnection costs (in excess of utility's own costs of interconnection)
	Capital costs (if any)	Distribution grid segment upgrades prompted by DER additions*
DER owners	Costs of DER adoption and operation	Measure costs (to participants)
		Interconnection fees
		Annual operations and maintenance costs
		Resource consumption by participant
		Transaction costs to participant

** At least some of this category of costs is often paid by DER developers*

As the descriptions below make clear, estimating DERs' benefits tends to require several more analytical steps than estimating their costs. Importantly, however, the relative ease of measuring costs is not a reason to ignore benefits and should be recognized as a source of potential over-weighting of costs and under-weighting of benefits in DER valuations.

> **Non-Wires Alternatives (NWAs)**
>
> NWAs generally combine a variety of DER types, ranging from energy-efficient lighting to battery storage. They deserve special mention because their development is generally led by utilities, which undertake them in lieu of distribution system upgrades that would be more expensive. Several states either direct or authorize retail utilities to recover the costs of NWAs through rates, so long as the suite of DERs performs as needed over the relevant timeframe.[30]

Bulk power system

Installing and operating DERs can avoid some of the costs to various stakeholders—and society as a whole—of operating the bulk power system. Those bulk power system costs that could be avoided include the generation of electricity (usually called "energy"), the capacity to generate electricity, ancillary services (i.e., measures that maintain voltage, frequency, and other features of the quality of delivered electricity), and additional costs, which arise indirectly from bulk power system operations, including hedges against changes in primary fuel prices and environmental compliance costs. The following brief descriptions summarize what gives rise to each of these costs and how DERs can potentially avoid them.

Energy costs. These costs reflect multiple factors, including the cost of the primary fuels used to generate electricity, availability of generation, congestion in the transmission system, and line losses. Because each of these constituent factors is sensitive to time and location, energy costs vary based on time and location.

Generation capacity and ancillary services. Retail utilities purchasing services from the bulk power system not only pay for electricity (akin to water flowing through a pipe), but also for (1) generators to invest in adequate capacity (i.e., a big enough pipe) to meet load under both ideal and adverse conditions in future years; and (2) the ancillary services

[30] *See* Brenda Chew et al., Non-Wires Alternatives: Case Studies from Leading U.S. Projects (2018).

required for electricity to maintain its voltage and frequency (akin to water that flows steadily and without turbulence or sloshing from side to side) required for smooth consumption. As with energy, regular auctions conducted by regional wholesale market managers assign prices to capacity and ancillary services.

DERs can help avoid the costs of energy, generation capacity, and ancillary services by reducing the need to deliver electricity to a particular location at a given time. Specifically, DERs can reduce the volume of bulk power system generation needed, avoid the need to turn on the most expensive generators in the fleet, and reduce both congestion and line losses in the short run. Over longer timeframes, DERs can obviate the need to build or maintain expensive generators altogether and can contribute to plans to reduce or eliminate congestion.

Other bulk power system costs. DERs can avoid several other costs, such as the financial risk arising from primary fuel price volatility, which results from changes in the supply of and demand for coal, natural gas, and uranium. These costs accrue in different ways, some of them easier to measure and relate to DER usage than others.

Distribution system

Location and timing of electricity consumption are as important to the costs of operating the distribution system as the bulk power system. Capital expenditure to replace, upgrade, or build new distribution system facilities is the largest component of distribution system costs.[31] Other significant costs include line losses between the bulk power system and customers, the fine balancing required to maintain power quality, and averting or dealing with reliability failures.[32] All of these costs can vary significantly across even small geographies and distribution system segments.[33]

DERs can help avoid some of these costs, depending on where DERs are located and when and how they operate.[34] For instance, if load in a particular location peaks when solar PV is most productive, then simple rooftop solar installations could offset growth in local demand for electricity and thereby help to avoid or defer the costs of upgrading local distribution facilities to handle that growth. However, if load peaks in the early evening, after the sun has set, then solar PV combined with storage could offset local load growth but a standalone rooftop solar PV installation could not. Another important factor affecting DERs' ability to avoid costs in a particular location is the availability of supporting infrastructure and assets, such as AMI. If the local distribution system is unable to make full use of DERs as compared to centralized resources, it could impede a local DER's performance and cost-effectiveness.[35]

Distribution system capacity can also be a *limiting* factor in relation to DER deployment. If the DER to be deployed is DG, then local distribution facilities must be able to absorb the excess generation it is expected to export to the grid—otherwise that DER would threaten reliability by sometimes overloading those facilities. This constraint is called "host-

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[31] *See* Tierney, *supra* note 28, at 17 ("the opportunity for greatest economic value rests with the ability . . . to avoid specific distribution-system upgrades"); Melissa Whited et al., Synapse Energy Econ. (prepared for Consumers Union), Caught in a Fix: the Problem with Fixed Charges for Electricity 26 (2016), https://perma.cc/RJ33-B8X7.

[32] *See* Paul De Martini & Lorenzo Kristov, Lawrence Berkeley Nat'l Lab., Distribution Systems in a High Distributed Energy Resource Future 21 (2015), https://perma.cc/PM66-D2LN.

[33] Bahramirad, *supra* note 28, at 6 (describing that system costs and thus potential DER value "varies not only by each of the approximately 5,500 feeders on the ComEd system [in and around Chicago], but potentially within a given feeder.").

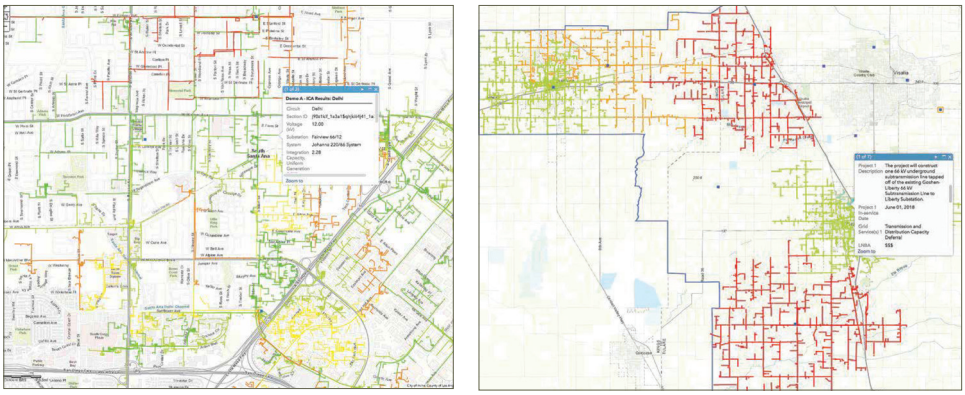
[34] Scott Burger et al., *Why Distributed?: A Critical Review of the Tradeoffs Between Centralized and Decentralized Resources*, 17 IEEE Power & Energy Mag. 16, 19 (2019) ("To capture locational value due to network constraints, DERs must be able to operate both where and when constraints are binding."); *see also* Revesz & Unel, *supra* note 8, at 74-75.

[35] Burger et al., *supra* note 34, at 19 (emphasizing relevance of binding performance constraints to valuation); Tierney, *supra* note 28, at 19 (similar).

ing capacity," and like the distribution system costs that DERs can avoid, it varies significantly across different locations. Upgrading distribution facilities specifically to increasing DER hosting capacity is a cost *caused* (rather than avoided) by DER. Notably, different types of DERs have different hosting capacity needs: whereas storage might require capacity to draw more electricity from the grid to charge at particular times, and solar-plus-storage or CHP might require capacity to export excess generation to the grid, some rooftop solar might be expected to simply reduce local loads and so can itself open up more local capacity.

Locational analyses done in California show how sensitive costs are to even small locational variations. The maps shown in Figure 4 below were developed by Southern California Edison.

Figure 4. Maps showing integration capacity (left) and locational net benefits (right).[36]



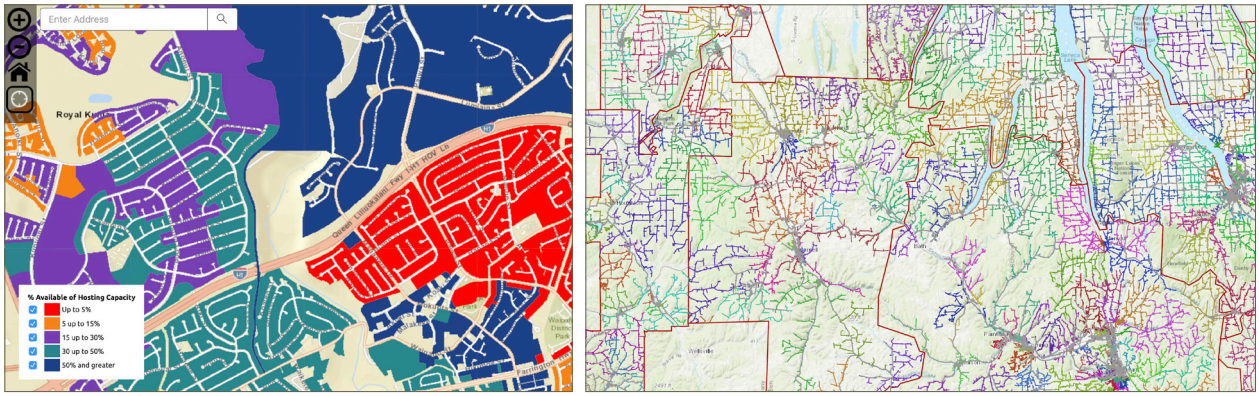
On the left panel, green indicates distribution line segments that can easily host additional DER capacity; red indicates little or no hosting capacity; yellow and orange are in between. On the right panel, green indicates line segments with higher expected value for DER due to an opportunity for deferral of distribution capacity upgrades; red indicates little or no value; yellow and orange are, again, in between.[37]

[36] Tim McDuffie, *Distributed Energy Resource Optimization*, SolarPro, July/Aug. 2018, at 39-40 figs.2, 3 & 4 https://www.solarprofessional.com/.

[37] Note that these maps reflect expected load growth as adjusted by the expected installation of DERs. The maps do not reflect the counterfactual scenario of distribution system costs with *no* DERs, which would reveal where and how much the installation of DERs could add value by avoiding those costs. In September 2017, California's Public Utilities Commission ordered the state's electric utilities to develop long-term forecasts of load growth and related distribution system costs, unadjusted by assumed DER installation, to facilitate clearer analyses of DERs' value. Decision on Track 1 Demonstration Projects A (Integration Capacity Analysis) and B (Locational Net Benefits Analysis), Cal. Pub. Utils. Comm'n Decision 17-09-026, Rulemaking 14-08-013, at 45-48 (Sept. 28, 2017), https://perma.cc/2Q4Q-NHSG. In June 2019, the Commission issued a white paper further specifying how utilities should comply. *See* Administrative Law Judge's Amended Ruling Requesting Comments on the Energy Division White Paper on Avoided Costs and Locational Granularity of Transmission and Distribution Deferral Values, Cal. Pub. Utils. Comm'n Rulemaking 14-08-013, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769 (June 13, 2019), https://perma.cc/R62G-BBZV.

As Figure 5 shows, Hawaii and New York State's utilities make similar "heat maps" and accompanying data available to DER developers.[38]

Figure 5. Oahu hosting capacity and locational value map (left); Hornell, NY hosting capacity map (right).



Maps like these show developers both where there is adequate capacity to accommodate DERs, and whether the addition of DERs would be likely to avoid costs to the distribution system. Recently updated (but still a work in progress)[39] Marginal Cost of Service Studies for New York distribution utilities provide a detailed description of the multiple components that underlie maps like these. For instance, the study conducted for Orange & Rockland examines the marginal cost of increasing existing capacity to serve prospective load growth for each of the utility's 50 feeders, and breaks that cost down into five "cost centers" for each feeder.[40] Placed on a map, that cost information would resemble the right panel of Figure 4 above. By examining load shapes on feeders with above-average costs, the Orange & Rockland study also highlights where DERs could avoid costs and the sort of load DERs would need to serve in order to do so.[41]

Effects beyond the electricity system

As indicated in Table 4, above, the activities involved in providing electricity services have numerous effects that are felt beyond the operation of the electricity grid. For instance, centralized, fossil-fueled electricity generators emit both greenhouse gases, which contribute to anthropogenic climate change, and local air pollution, which results in direct harms to public health and the environment. Centralized electricity generation also consumes water resources and results in water pollution (thermal and toxic), among other impacts. Installing and operating DERs can avoid these detrimental effects. DERs can also improve electricity system resilience to disruptions, such as from storms and wildfires that are expected to

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[38] Hawaiian Electric, Oahu Locational Value Map (LVM), https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/locational-value-maps/oahu-locational-value-map-(lvm) (accessed Nov. 21, 2019); New York State Electric & Gas and Rochester Gas & Electric, Distributed Interconnection Guide Map, https://iusamsda.maps.arcgis.com/apps/webappviewer/index.html?id=2f29c88b9ab34a1ea25e07ac59b6ec56 (accessed Nov. 21, 2019).

[39] *See, e.g.,* Synapse Energy Econ. (prepared for Clean Energy Parties), Appendix B: Information Requests Round #2 Regarding NY Utilities' MCOS Studies, N.Y. Pub. Serv. Comm'n Case 19-E-0283, Proceeding on Motion of the Commission to Examine the Utilities' Marginal Cost of Service Studies (Sept. 16, 2019), https://perma.cc/JT4L-3S7R; City of New York's First Set of Information Requests to Consolidated Edison Company of New York, Inc. Regarding Its Marginal Cost of Service Study, N.Y Pub. Serv. Comm'n Case 19-E-0283, Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies (July 15, 2019), https://perma.cc/2QD7-92CT.

[40] Philip Q. Hanser et al., The Brattle Grp. (prepared for Orange & Rockland), Marginal Cost of Service Study, 16 tbl.8 (2019). The "[Marginal Cost] Map" in the study itself appears on page 27.

[41] *Id.* at 20, 22.

increase in frequency and severity as the climate changes.[42] And DERs can help provide predictable and secure electricity access for low-income individuals and communities.[43]

Quantifying and monetizing some of these effects, like reduced water usage, is straightforward because the necessary data inputs and valuations are generally already available from prices assigned by markets or regulators.[44] Monetizing others, like the global and local costs of emissions, requires data to be gathered and analyzed, but, as explained below, can be made a routine step in electricity-related cost accounting.[45] Monetizing still others, such as improved resilience to disruption, often requires more significant and project-specific analysis.[46]

Finally, DERs can affect local economic activity, either by promoting local spending and causing job creation or undermining economic activity that relies on the operation of centralized resources.[47] These effects can be monetized but are rightly considered benefits or costs to *local* communities only—to society as a whole they might not represent a benefit or cost per se but a mere transfer of resources.

Specifying a baseline for scenario analysis

Estimating the value that a DER provides to society requires two scenarios—the baseline or "business as usual" scenario in which grid-based assets and existing DERs provide service, and the alternative scenario in which new DERs account for some or all of the relevant service provision. If a baseline is not updated with appropriate frequency, then it provides an inaccurate set of parameters for comparison to the new DER deployment scenario. It is, therefore, necessary to establish and maintain data sources for deriving accurate baseline values, and to correctly specify intervals for updating data inputs.

Calculating the value of distributed energy resources

Assigning monetary value to the operation of a DER at a particular time and place builds upon the data requirements and analytical decisions described above, namely identifying benefits and costs, deciding which are relevant, and specifying key features of the DER project and the baseline scenario to which it is an alternative. Valuing the effects of a specific DER's operation in comparison to a baseline scenario involves five component steps:

(1) identifying the resource(s) whose operation will be modified or displaced by operation of the DER;

(2) characterizing the timing and degree of that modification or displacement by comparing DER operation/output to that of the displaced resource(s);

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[42] Resilience is distinct from reliability, the costs of which are already internalized in the rates paid for electricity service. Nat'l Acad. Scis., Eng. & Med., Enhancing the Resilience of the Nation's Electricity System 9 (2017), https://doi.org/10.17226/24836. [hereinafter "NAS, Enhancing Resilience"].

[43] Gridworks et al., *supra* note 29, at 4, 9.

[44] *See, e.g.*, Indep. Evaluation Monitor, Arkansas Technical Reference Manual, Protocol L, Version 7.0, at 88-90 (Aug. 2016), https://perma.cc/2ZXC-BWTN (describing derivation of value of avoided water use from retail water rates).

[45] *See generally* Jeffrey Shrader et al., Inst. for Pol'y Integrity, Valuing Pollution Reductions: How to Monetize Greenhouse Gas and Local Air Pollutant Reductions from Distributed Energy Resources (2018), https://policyintegrity.org/publications/detail/valuing-pollution-reductions.

[46] For an example of this sort of analysis, *see* San Francisco's analysis of the resilience value of adding solar + storage facilities to shelters and public libraries throughout the city. Abigail Rolon et al., Arup (for San Francisco Dep't of the Env't), Solar and Energy Storage for Resiliency (2018), https://perma.cc/9FFU-MV9R. For a general methodology for monetizing resilience value, see Burcin Unel & Avi Zevin, Inst. for Pol'y Integrity, Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System (2018), https://policyintegrity.org/publications/detail/toward-resilience.

[47] *See* Woolf et al., *supra* note 29, at 4, 17 n.8, 33.

(3) estimating the costs avoided as a result of this displacement (including the costs of infrastructure development and pollution);

(4) comparing those avoided costs to the costs of installing and operating the DER; and

(5) determining the appropriate frequency of and process for updates.[48]

The rest of this subpart describes how these steps apply to different categories of benefits DERs could provide.

Avoided bulk power system costs

Wholesale electricity markets already do much of the analysis required to assign a monetary value to a DER's avoidance of bulk power system costs. The following short descriptions build on those above. Implementing what is described here requires access to models of the relevant bulk power system region and detailed knowledge of the profile of the DER to be deployed.

Generation. The locational marginal price (LMP) is the marginal cost of providing electricity to a specific location (either a zone or node) in the bulk power system at a specific time.[49] More specifically, it reflects three costs: generation, congestion (i.e., costs incurred to deal with transmission capacity limits), and transmission system line losses.[50]

Calculating the value of avoided generation relies heavily on LMP, which is specified at the level of a wholesale market zone,[51] as shown on the map of real-time wholesale zonal prices in figure 6, below, or a transmission system node.

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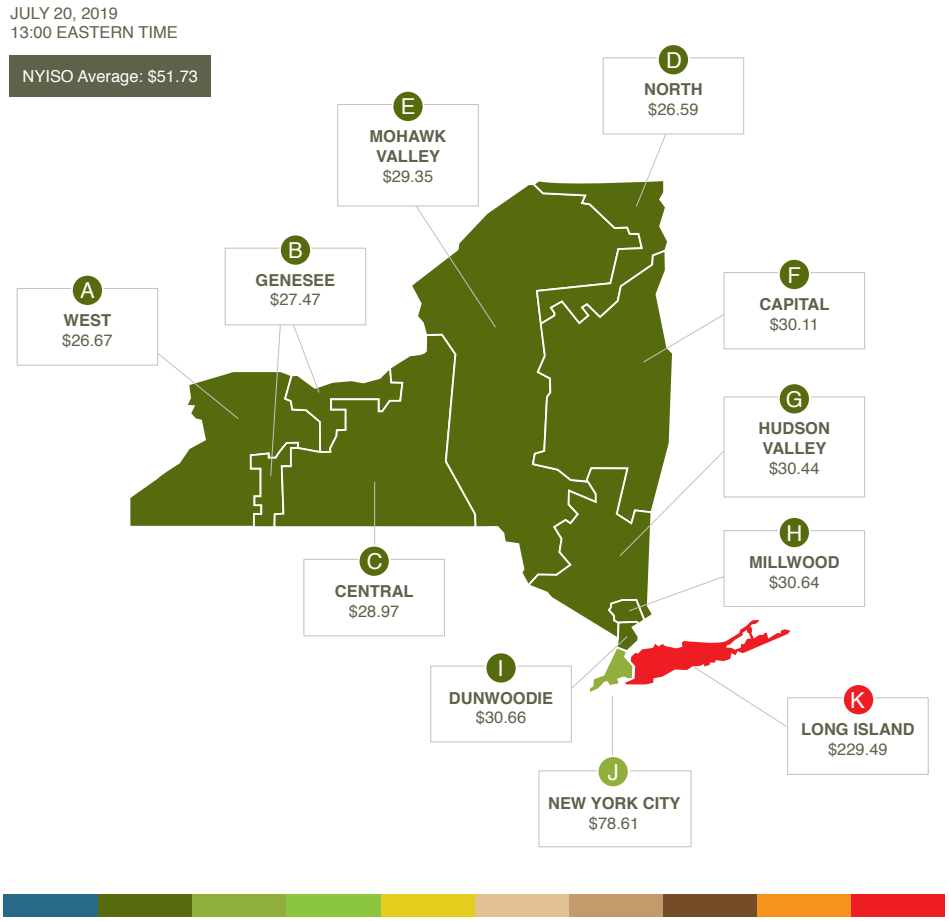
[48] *Cf.* Natalie Mims Frick et al., Lawrence Berkeley Nat'l Lab., A Framework for Integrated Analysis of Distributed Energy Resources: Guide for States 7-8 (2018), https://perma.cc/CNG2-N6KC (listing "minimum data requirements" for DER valuation).

[49] Fed. Energy Reg. Comm'n, Energy Primer: A Handbook of Energy Market Basics 60-61 (2015), https://perma.cc/AAU7-JZYN.

[50] This calculation can use the systemwide annual average rate of line losses, but it is more accurate to use the marginal loss rate for the relevant zone or node over different time periods, e.g., seasonal and daily. This granularity is important because loss rates tend to be higher at peak times and increase over greater distances. NYISO, for example, uses a marginal rate. New York Independent System Operator, Market Services Tariff § 17.2.2.1 (Aug. 16, 2019) ("Marginal Losses Component LBMP").

[51] In locations where electricity system ownership is vertically integrated and no wholesale market operates, estimates of marginal energy costs can be derived from "system lambda," an engineering statistic used to estimate the shadow cost of a one-unit change in production. *See* Severin Borenstein & James Bushnell, Energy Inst. at Haas, *Do Two Electricity Pricing Wrongs Make a Right? Cost Recovery, Externalities, and Efficiency* 11 (Nat'l Bureau of Econ. Research, Working Paper No. 24756, 2019), https://perma.cc/FJ9D-KQ6Y.

Figure 6. Real-time energy prices (LMP) across New York Independent System Operator (NYISO) Zones A through K at 1pm on July 20, 2019.[52]



Zonal prices sometimes diverge significantly, for instance when extreme weather occurs in combination with congested transmission capacity. Figure 6 shows the zonal prices at 1pm on July 20, 2019, the hottest day of 2019 in New York State. From 11:00am to 10:00pm on that day LMP for Zone K (Long Island) ranged from just over twice the NYISO average to almost six times the average.[53] That ratio was highest at 2:15pm, when the LMP in Zone K was over $360/MWh and the average of all 11 NYISO zones was just under $62/MWh.[54] The limited capacity of congested transmission facilities to carry more electricity to Long Island accounted for most of the difference at that hour.[55]

Generation capacity. In regions with competitive wholesale markets, auctions between generators and wholesale electricity purchasers (chiefly retail utilities, but also competitive retail providers in states with retail choice) establish the

[52] For the sake of simplicity and clarity, this report draws heavily on the example of the New York State electricity grid, where the ISO and wholesale market's boundary matches that of the state. Other ISO/RTO regions operate in a broadly similar fashion—deriving prices for energy, capacity, and ancillary services from regular auctions—but contain multiple states (e.g., ISO-NE, PJM, SPP, and MISO) or portions of individual states (e.g., ERCOT and CAISO).

[53] Data retrieved from NYISO's Open Access Same-Time Information System, Real-Time Market LBMP, Zonal, Archived File "07-2019", http://mis.nyiso.com/public/P-24Alist.htm.

[54] *Id.*

[55] *Id.*

prices for future generation capacity. These vary across regions and from year to year, but generally amount to a fraction of the total price paid for bulk power system services.[56]

Calculating the value of avoided generation capacity requires three sets of data points:

- the effective capacity of the DER across specified time periods, such as daily peak loads in a given zone or node for all four seasons;
- expected system capacity needs over the same time periods; and
- the expected *value* of future capacity, based on the prices assigned by the wholesale market for the relevant timeframe.

Armed with these data, it is possible to estimate how much the contribution of the DER in a given location will reduce local capacity needs and thereby lower capacity prices.

Transmission. In addition to transmission congestion and line losses, which are short term costs reflected in LMP, DERs can also potentially avoid the longer-term costs of transmission capacity additions. Those longer-term costs are substantially reflected in generation capacity prices and the congestion component of LMP, which captures what wholesale electricity purchasers are willing to pay over the short-term to overcome the transmission constraints in a particular location by buying electricity from accessible resources and routing it around the constraints. But relying on LMP can risk ignoring DERs' potential to avoid significant long-term costs.[57] A more focused calculation of the avoided cost of additional transmission can be done either by estimating the relationship between planned transmission capacity additions and their associated revenue requirements,[58] or by a more intensive modeling exercise that estimates the sensitivity of transmission capacity needs to incremental changes in load of the sort affected by the installation and operation of DERs.[59]

Ancillary services and other bulk power system costs. Even though the remaining bulk power system costs identified in Table 4 above tend to be small relative to generation and generation capacity, DERs' ability to avoid such costs can be valuable. In addition to being relatively small, however, these avoided costs are generally harder to calculate precisely—and extremely difficult to calculate for particular times and locations. This is why the tool that California utilities have been directed to use as the basis for the Locational Net Benefits Analysis of DERs simply calculates ancillary services as 0.9% of the value of generation.[60] Calculating the value of avoided fuel price volatility requires several analytical steps to translate from an estimated cost to a unit of marginal value made available by installing and operating a DER.[61]

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[56] David B. Patton et al., Potomac Econ., 2018 State of the Market Report for the New York ISO Markets 3 fig.1 (2019), https://perma.cc/V73H-3N2T.

[57] Clean Energy Parties, Proposal for Distribution and Transmission Value for Distributed Energy Resources (DERs) and DRV/LSRV Modifications, N.Y. Pub. Serv. Comm'n Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources Working Group Regarding Value Stack 22-23 (June 7, 2018) https://perma.cc/BUA7-Z2GN.

[58] For an example of a regression analysis developed to estimate this value, see Reuben Behlihomji et al., Southern California Edison, Co., Phase 2 of 2018 General Rate Case Marginal Cost and Sales Forecast Proposals, Application No. A.17-06-030, Ex. SCE-02A, at 36-39 (Nov. 1, 2017), https://perma.cc/5RDP-N5L3.

[59] *See* Clean Energy Parties filing, *supra* note 57, at 23 (describing version of NYISO Reliability Needs Assessment that would detect the value of such incremental changes).

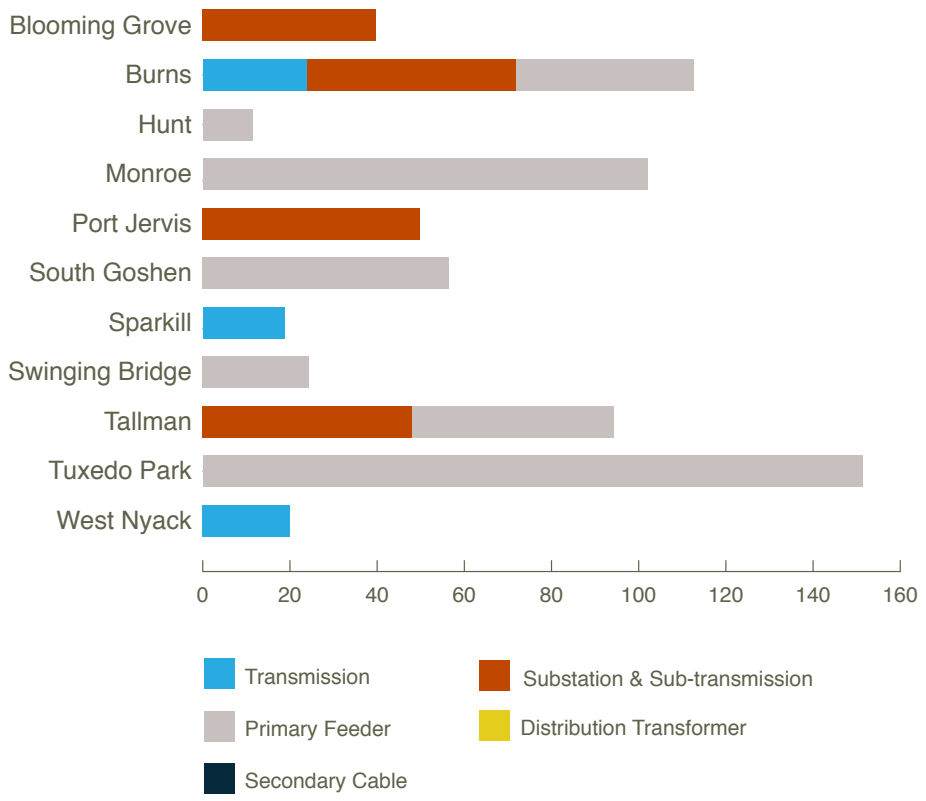
[60] Cal. Pub. Utils. Comm'n, Cost-effectiveness: 2019 Avoided Cost Calculator, ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/CostEffectiveness/ACC_2019_v1b.xlsb ("General Inputs" tab) (accessed Aug. 25, 2019). That calculation also excludes the value of regulation "up" or "down" from its estimate. *Id.*

[61] For a description of one approach, *see* Daymark Energy Advisors (for Maryland Pub. Serv. Comm'n), Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland 115-120 (2018), https://perma.cc/J3P9-UMU2.

Avoided distribution system costs

From a policymaker's perspective, determining the benefits of DERs to the distribution system only requires understanding the costs that DERs could avoid, like line losses and the marginal cost of adding distribution capacity. The Marginal Cost of Service Study commissioned by Orange & Rockland, a utility that serves the counties just northwest of New York City, describes the marginal costs of investments required to match expected load growth for each of the utility's 50 feeders.[62] The study breaks those marginal costs down into five "cost centers" or categories of infrastructure for each feeder. As shown in Figure 7, which depicts a characteristic sample of those 50 feeders, there is significant locational variation between services areas, and no costs are expected for two of those cost centers.

Figure 7. Marginal costs of planned capacity additions ($/kW) in sample of feeder areas in Orange & Rockland's service territory.[63]



According to its 2019 Marginal Cost of Service Study, Orange & Rockland does not plan to incur any capital costs for 28 of its 50 feeders over the coming decade. Nor does any feeder require upgrades or replacement of distribution transformer or secondary cable facilities in that time. But, as shown by Figure 7, maintaining service at the Burns location will require investments in transmission, substation, and primary feeder facilities; and at Tuxedo Park a very large investment in the primary feeder is necessary.

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[62] Hanser et al., *supra* note 40, at 16 tbl.8.
[63] *Id.*

Although line losses represent a small portion of the distribution costs that DERs can potentially avoid, they are still substantial.[64] Importantly, because line losses can vary significantly across a given utility's service territory and at different times,[65] using an average rate of line losses will likely distort any estimate of how much of that cost a DER could potentially avoid.[66]

Private decisions of DER developers and would-be owners about whether to install new DERs must also take into account available hosting capacity[67] and the compatibility of DER profiles with local "load shapes"—that is, the level and timing of local aggregate demand to understand whether it makes economic sense for them to install DERs. Compensating DERs for helping to avoid these sorts of costs sends a clear signal to DER developers and would-be owners about where to locate new DERs and what sorts of DERs to install there. In locations where a given DER's excess generation would help avoid distribution system costs by serving peaks in local load, a value stack will compensate that DER for providing a more cost-effective alternative to centralized system upgrades.

* * *

Taking the analytical steps described above results in an estimation of the value of particular DERs in a particular location. However, actually developing those DERs requires a degree of certainty about the compensation that will stem from that estimation. Due to the routine nature of wholesale market price patterns, many of the relevant avoided costs are predictable (including the value of avoiding wholesale generation, generation capacity, transmission, and other bulk power system costs). But local distribution system costs, as Orange & Rockland's Marginal Cost of Service Study shows, do not change on a uniform schedule and respond to changes in load, which are less predictable than the changes that inform bulk power system prices. This variability can undermine the usefulness of information provided by utilities to DER developers, if the DER compensation scheme employs a time horizon that is shorter than the amortization period used by the local utility for distribution infrastructure. Part III discusses options for balancing different stakeholders' interests and needs for accurate and predictable information about distribution system costs.

Avoided emissions of greenhouse gases and local pollutants

Potential benefits of DERs include avoiding emissions from centralized electricity generation. As with other benefits described above, the benefits of avoided emissions vary with time and place. With respect to greenhouse gas emissions—pollutants with global rather than local effects—that variation results from the different marginal emissions rates of whatever resources the DER's operation displaces. With respect to local air pollution, that variation owes to the marginal emissions rate of the displaced resource, location of populations near or downwind of that resource, and prevailing weather patterns.

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[64] *See, e.g.*, Xcel Energy Servs., Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System—Study Report in Response to Colorado Public Utilities Commission Decision No. C09-1223, at v & 31-34 (May 23, 2013), https://perma.cc/9F54-5RXB.

[65] Borenstein & Bushnell, *supra* note 51, at 12-14.

[66] Some states direct utilities to calculate and report line losses on a marginal basis. *See* Testimony of Chris Neme on behalf of the N. Carolina Justice Ctr. et al., N.C. Utils. Comm'n Docket No. E-2, SUB 1174, In the Matter of Application of Duke Energy Progress, LLC, for Approval of Demand-Side Management and Energy Efficiency Cost Recovery Rider Pursuant to G.S. 62-133.9 and Commission Rule R8-69, at 7, 30 (Sept. 4, 2018), https://perma.cc/7J6Y-NV6J. In states that allow utilities to report average rates, this small piece of a value stack is likely to be inaccurate. *See* Jim Lazar & Xavier Baldwin, Reg'y Assistance Project, Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements 3-5 (2011), https://perma.cc/TX57-GA6D (describing how averages understate line losses).

[67] Utilities generally charge DER developers the cost of expanding hosting capacity to accommodate a new DER installation.

Calculating the volume of emissions avoided requires detailed information about the type of pollution and marginal emissions rates of regional generation resources over the smallest possible intervals of time. Calculating the value of avoiding those emissions requires estimating the damage they would have done. For greenhouse gases, the best available tool for estimating the monetary value of damages from each increment of emissions is the Social Cost of Carbon, which was developed by the Interagency Working Group in 2010, and then updated in 2013 and 2016.[68] For local pollutants, several tools exist for estimating the monetary value of damage done, including BenMAP, EASIUR, AP2, and COBRA.[69]

Policy Integrity has previously described a five-step method for developing monetary estimates of emissions reductions attributable to DERs in *Valuing Pollution Reductions: How to Monetize Greenhouse Gas and Local Air Pollutant Reductions from Distributed Energy Resources*.[70] That report includes methodologies, data sources, and analytical tools for each of the following steps:

1. Determine what generation resource(s) will be displaced by a DER's installation/operation;
2. Quantify marginal emissions rates of the displaced generation;
3. Calculate in monetary terms the damages of relevant emissions generally, with attention to types of pollutants, their destinations, and the timing (seasonal and daily) of their emission;
4. Monetize the value of emissions avoided by displacing generation using the marginal emissions rates established by Step 2 and the per unit damages established by Step 3 (taking care to consider emissions priced fully or partly by existing policies and to adjust as needed to avoid double-counting);
5. Subtract from the result of Step 4 the value of any emissions directly attributable to operation of the DER.

Notably, Steps 3 and 4 are significantly easier to complete for greenhouse gas emissions than for ambient air pollution.

Improved resilience

Electricity system resilience is distinct from reliability.[71] Reliability focuses on high-probability, low-impact events, like downed tree limbs, and is concerned with preventing outages that might result. By contrast, resilience focuses on low-probability, high-impact events, like hurricanes or large-scale cyberattacks, and is concerned with resisting, absorbing, and recovering from the disruption they cause.[72] In addition, unlike with reliability, there is no single metric or set of metrics that indicate resilience to all types of hazard.[73] Instead, resilience is specific to a type of hazard, such that a system designed to be resilient to cyberattack *might* but will not necessarily also be resilient to hurricanes or wildfires. These features make it harder, but certainly not impossible, to calculate the resilience value of a DER.

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[68] Interagency Working Group on the Social Cost of Greenhouse Gases, Technical Update on the Social Cost of Carbon for Regulatory Impact Analysis (2016), https://perma.cc/UYX6-2W8M.

[69] For a summary description of each of these models and references to fuller descriptions, *see* Jeffrey Shrader et al., *supra* note 50.

[70] *Id.*

[71] NAS, Enhancing Resilience, *supra* note 42, at 9.

[72] *Id.* at 10 ("Resilience is not just about being able to lessen the likelihood that outages will occur, but also about managing and coping with outage events as they occur to lessen their impacts, regrouping quickly and efficiently once an event ends, and learning to better deal with other events in the future."); *see also* Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, 162 FERC ¶ 61,012 P 22 (2018) (citing National Infrastructure Advisory Council's Critical Infrastructure Resilience Final Report and Recommendations 8 (Sept. 2009)).

[73] Standard reliability metrics include the System Average Interruption Frequency Index (SAIFI) and System Average Interruption Distribution Index (SAIDI), which measure different aspects of system performance and show no differences in sensitivity to different sources of disruption.

Over the past decade, resilience has become a greater priority for policymakers with responsibility for different segments of the electricity grid,[74] owing to increasingly frequent and severe climate-driven weather events, and recognition of the electricity grid's susceptibility to cyberattack.[75] However, determining the value of avoiding disruption, and, further, of particular investments that could achieve such avoidance, has proved challenging.[76] Policy Integrity's 2018 report, *Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System*,[77] offers guidance on this issue. Drawing on the academic literature, it proposes calculating the resilience value of any investment or intervention using the following five analytical steps:

1. Characterize potential sources of disruption;
2. Specify metrics for resilience; each metric should—
    - Be measurable in terms of the consequences expected to result from particular threat types;
    - Reflect uncertainty (e.g., the expected consequence or the probability of the consequence occurring exceeds an acceptable level); and
    - Use data from computation models that incorporate historical experience or expert evaluation.
3. Quantify system resilience in a baseline scenario;
4. Characterize how the investment or intervention would modify system resilience; and
5. Compare the benefits and costs of the resulting resilience improvement.[78]

These steps are broadly consistent with approaches developed by other researchers to estimate the resilience value of DERs.[79]

This approach can also be supplemented by valuing community resilience.[80] This distinction is noteworthy because state-level policies adopted to promote resilience often aim at the communities and individuals that rely on public health and safety services, many of which rely on electricity.[81]

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[74] *See, e.g.*, Arthur Maniaci, NYISO, *2019 Climate Study – Draft Outline of Statement of Work for RFP* (Nov. 9, 2018), https://bit.ly/2HrKCJm; Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal, N.Y. Pub. Serv. Comm'n Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service (Feb. 21, 2014), https://perma.cc/6WAP-ATHM (directing ConEd to undertake a Climate Change Vulnerability Study and implement responses to its findings).

[75] NAS, Enhancing Resilience, *supra* note 42, at 10-12.

[76] Wilson Rickerson et al., Converge Strategies (prepared for NARUC), The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices (2019), https://perma.cc/P7YZ-STEY.

[77] Unel & Zevin, *supra* note 46.

[78] As noted in Policy Integrity's report, these steps are a streamlined version of the steps and data requirements developed by Sandia National Laboratory as part of the DOE Metrics Analysis for Grid Modernization Project. *See* Eric Vugrin et al., Sandia Nat'l Labs., Resilience Metrics for the Electric Power System: A Performance-Based Approach (2017), https://perma.cc/CK3F-SF5A.

[79] *See* Rickerson et al., *supra* note 76.

[80] For the definitions of these two types of resilience, compare NAS, Enhancing Resilience, *supra* note 42, at vii, *with* Nat'l Acad. of Sci., Eng'g & Med, Building and Measuring Community Resilience: Actions for Communities and the Gulf Research Program 12-13 (2019), and Nat'l Inst. Sci. & Tech, Community Resilience Planning Guide for Buildings and Infrastructure Systems, vol. 1, at 13 (2016), https://perma.cc/68TB- 5B98.

[81] For a discussion of the challenges arising from improving not only the resilience of electricity services but also community resilience, *see* Justin Gundlach, *Microgrids and Resilience to Climate-Driven Impacts on Public Health*, 18 Houston J. Health Pol'y & L. 77 (2018); *see also* Rolon et al., *supra* note 46 (estimating resilience value to the city and county of San Francisco of adding solar plus storage installations to local shelters and libraries).

III. Reasons to move beyond net energy metering

NEM programs in many states, though not all, have enabled a significant amount of private investment in DERs—particularly solar PV. However, because NEM programs' compensation of DERs generally ignores temporal and locational value, NEM is at odds with this report's recommended approach to valuing DERs over the long-term, once a critical mass of DERs has been installed in a given utility service territory.

As explained below, the crux of the problem with NEM lies in its reliance on retail rates. Small retail electricity customers generally pay for electricity service through a monthly, two-part tariff. One part of that rate is fixed, meaning that it does not vary with the customer's electricity usage. The other part is volumetric, meaning that customers pay for the kWh of electricity they consumed during each billing period. The price multiplied by the customer's monthly kWh is "flat" across all the hours of the month. The vast majority of ratepayers are charged a bundled, flat rate for consuming electricity. The rates paid by larger commercial and industrial customers often also include a "demand charge" that reflects their peak demand during each billing period.

The shortcomings of net energy metering

Because NEM compensates DERs based on the net consumption of the customer, it relies on the underlying retail rates.[82] If these retail rates are bundled rates (and for most consumers they are), NEM does a poor job of capturing the benefits and costs of DERs in a granular way.

Reliance on partial and distorted price information

NEM's reliance on retail rates causes three types of problems: it distorts economic signals about efficient DER deployment and operation, it ignores important benefits and costs, and it shunts non-DG DER into a different set of compensation and planning processes, which also distorts economic efficiency.

Distorted economic signals. Nearly all retail utilities charge their customers based on the average cost of electricity service in the utility's territory over each billing period. As a result, most utilities charge a flat price of electricity service for that period, even though the *costs* of providing that service vary significantly across both time (minute, hour, day, season) and location (distribution system line and feeder, and bulk power system node and zone). This discrepancy between price and cost leads customers to not see accurate price signals about the underlying costs when they consume electricity, leading to economically inefficient consumption. Furthermore, because every customer pays the same retail rate regardless of where and when they consume electricity, those who use electricity during cheaper off-peak times cross-subsidize those who use electricity during more expensive peak times. Similarly, those who use electricity at less congested locations, cross-subsidize those who use electricity at congested locations.[83]

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[82] *See* Revesz & Unel (2017), *supra* note 8, at 60 (noting that 34 jurisdictions credited NEM participants at the retail rate in 2017).

[83] Distribution facilities experience increased wear and tear at near-peak times. Thus, flat pricing at near-peak times results in indifference to the capital costs of distribution system upkeep—costs that utilities generally seek to recover through charges that capture the coincidence of customers' maximum level of demand with maximum local demand on the distribution system ("coincident peak demand").

By basing compensation to DER owners on the flat retail rate, NEM creates for DER owners the same distortions that lead electricity customers to consume inefficiently. That is, DER owners receive an average price for their electricity even at times when its value to the centralized grid far exceeds (or falls below) the monthly average, and even in places where it alleviates (or creates) costs. As academic researchers and the New York State Energy Research and Development Authority (NYSERDA) found in one study, causing DERs to be deployed and operated at the wrong times and in the wrong places can lead NEM's costs to exceed its benefits.[84]

Ignored benefits and costs. Because it is based on retail rates, NEM only reflects the benefits and costs included in a utility's perspective on value. It ignores other benefits and costs, like public health benefits of avoided emissions, treating them as externalities to which electricity prices should be indifferent. Ignoring externalities like these causes decisions about electricity consumption and electricity system design—and DER installation and operation—to be needlessly net-costly to society. Notably, these benefits and costs also—like the system costs highlighted in the previous paragraph—generally depend on time and place.[85]

Fragmentary compensation for DER subcategories. The rules that currently govern compensation for DG and different types of non-DG DERs generally *prevent* direct competition among them by causing compensation to flow to different technologies through distinct channels at different rates. As a consequence, different resource types that provide comparable services often do not compete in a direct and meaningful fashion. As shown in table 6, there is little overlap among compensation mechanisms for different types of DER.

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[84] Sexton et al., *supra* note 9, at 3-4, 29-31; Kush Patel et al., Energy+Environmental Economics (prepared for N.Y. State Energy Research & Dev. Auth. and N.Y. State Dep't of Pub. Serv.), The Benefits and Costs of Net Metering in New York 51-62 (2015), https://perma.cc/3L5C-K73K.

[85] *See* Shrader et al., *supra* note 50, at 4.

Table 6. Compensation mechanisms for different DER categories.

Type of DER	Main compensation, cost recovery, and subsidy mechanisms
DG	NEM,[86] and numerous grant, rebate, tax credit, and other programs to reduce the costs of installation.[87]
Standalone BTM energy storage	Energy storage deployed by customers "behind the meter" is generally valued by its owners because it can help avoid consumption of grid-based electricity (along with associated demand charges for commercial and industrial customers), or provide backup power during an outage.[88] Subsidies for deploying energy storage vary by state. Some are grants that reduce the cost of deployment.[89] Others seek to encourage storage to reduce peak usage and to displace high-emitting generation resources, by compensating storage that charges at times when the marginal emissions rate of grid-based electricity generation is low and to discharge when it is highest.[90]
Demand response	Wholesale demand response programs compensate demand response resources like generation capacity and delivered generation, based on bids that clear in wholesale capacity and energy market auctions. Retail demand response programs compensate different demand response providers differently: residential customers subject to time-of-use rates save when they avoid higher-priced periods; residential customers subject to flat rates generally receive bill credits; and participating commercial and industrial customers might receive capacity or performance payments (similar to wholesale "capacity" and "energy") as either bill credits or monetary compensation.
Energy efficiency	Customers who invest in EE can recover their costs through reduced energy consumption. Utilities subject to legislative and regulatory mandates can often also recover the costs of making or subsidizing qualifying EE investments through rates and other regulatory mechanisms.[91] In addition, commercial consumers in at least 20 states (and residential consumers in three states and multiple localities) can access low-cost financing for EE investments through PACE programs[92] and recover payments through each participant's property tax bill.
Non-wires alternatives (NWAs)	As noted above, some states direct or authorize retail utilities to recover the costs of NWAs through rates, so long as the suite of DERs perform as needed over the relevant timeframe.[93]

Net energy metering and "fairness"

As explained above, NEM's earliest defining feature was that it enabled DER compensation without disrupting other aspects of providing centralized electricity services, such as metering, billing, and regulatory and tax treatment of flows of electricity and money. How NEM allocates benefits and costs, both between NEM program participants and other ratepayers, and between NEM program participants and utilities, has always been incidental to that more basic priority.

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[86] For a survey that provides summary descriptions of DG compensation schemes for all 50 states as of September 2018, see Memorandum from Juliet Homer & Alice Orrell, Pacific Nw. Nat'l Lab., to Stacey Donohue, Idaho Pub. Util. Comm'n, Distributed Generation Cost-Benefit and Ratemaking Considerations for Idaho 8 (Jan. 25, 2019), https://perma.cc/JK4K-4B4E.

[87] For a comprehensive list of state and federal level programs, see the "Programs" webpage of NC Clean Energy Technology Center's Database of State Incentives for Renewables & Efficiency, *supra* note 29, (accessed Aug. 27, 2019).

[88] Garrett Fitzgerald et al., Rocky Mtn. Inst., The Economics of Battery Energy Storage: How multi-use, customer-sited batteries deliver the most services and value to customers and the grid 4 (2015), https://perma.cc/7MHL-2A8G.

[89] *See, e.g.*, Julian Spector, *New York's Energy Storage Incentive Could Spur Deployment of 1.8GWh*, GreenTech Media, Apr. 29, 2019, https://perma.cc/E9U4-CZ7Y; Sarah Shemkus, *Massachusetts Grants Help Get Energy Storage Projects off the Ground*, Energy News Network, Nov. 8, 2018, https://perma.cc/5G5R-9L4P.

[90] *See, e.g.*, Decision Approving GHG Emission Reduction Requirements for the Self Generation Incentive Program Storage Budget, Cal. Pub. Utils. Comm'n Rulemaking 12-11-005, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues (Aug. 9, 2019), Mass. Dep't of Energy Resources, The Clean Peak Energy Standard: Draft Regulation Summary (Aug. 7 & 9, 2019), https://perma.cc/2ZT8-YDNZ.

[91] *See* Am. Council for an Energy Efficient Economy, Energy Efficiency Resource Standard, https://perma.cc/6YUQ-8XVC (accessed Oct. 22, 2019) (listing policies of various states).

[92] PACENation, *PACE Programs Near You*, https://pacenation.us/pace-programs/ (accessed Aug. 27, 2019).

[93] Brenda Chew et al., Non-Wires Alternatives: Case Studies from Leading U.S. Projects (2018).

And yet, even though fairness was never the main priority of the design of NEM programs, their "fairness" has received a great deal of attention by commentators and public service commissions in recent years.[94] Some discussions of NEM's fairness focus on whether NEM results in a "cross-subsidy" or "cost shift," whereby DER owners' patterns of electricity consumption and compensation for excess generation leads them to contribute disproportionately less to the revenues utilities rely on to cover the costs of providing centralized electricity services. As a result, so goes the argument, customers with no DER end up paying a disproportionately greater share of utility costs.[95] Other discussions of fairness focus on whether NEM is "fair" to utilities, which receive less in bill payments from NEM participants yet must maintain the infrastructure that supports those participants' continued access to centralized resources.[96]

This report does not attempt to define fairness or to articulate whether or how NEM could be made fair. Instead, it argues that the question of NEM's "fairness" arises from misplaced reliance on retail rates, which are necessarily based on an unduly narrow perspective on benefits and costs. The question of fairness can be best dealt with by adopting a broader perspective and allocating the benefits and costs encompassed by *that* perspective in accordance with principles of economic efficiency and cost causation—steps embodied in the value stacking mechanism described below. Taking these steps recognizes the value contributed by DERs and compensates those contributions for that value, but not more. Unfortunately, resolution of this sort is seldom if ever considered in arguments over whether NEM is unfair and in need of correction. Instead, demands for so-called fairness have given rise to tight caps on NEM eligibility and non-coincident demand charges for NEM program participants,[97] measures that establish more stable revenue streams for utilities[98] but do not cause DERs to be compensated more accurately in light of their benefits and costs to society.

* * *

NEM has enabled the initial deployment of renewable DERs in many jurisdictions,[99] but as those deployments have grown, state authorities have begun to re-examine NEM.[100] Indeed, many if not all states that allow DERs to interconnect and compete with centralized grid resources are either exploring or implementing changes to their original NEM programs (see callout box).[101] For the reasons presented above—some of them valid, others debatable—states want to move beyond NEM. Some also want to move to an approach centered on value stacking.

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[94] *See, e.g.*, Geffert & Strunk, *supra* note 11, at 37 (examining whether NEM is unfair to non-participants and utilities and concluding that it is unfair to both).

[95] *But see* Memo from Homer & Orrell, *supra* note 86, at 8. ("cost shifts can go both ways"); *see also* Barbose, *supra* note 28, at 30-31 (concluding that NEM often leads to cost shift but in de minimis amounts that do not materially affect ratepayers).

[96] *See, e.g.*, Lindsey Hallock & Rob Sargent, Shining Rewards: The Value of Rooftop Solar Power for Consumers and Society 15-16, tbl.2 & fig.1 (2015), https://perma.cc/2Y5P-E9PC (showing that sponsorship and methodology of 11 "value of solar" studies generally predicts conclusions about utility cost recovery from DER owners).

[97] For examples, see Melissa Whited et al., Synapse Energy Econ. (prepared for Consumers Union), Caught in a Fix: the Problem with Fixed Charges for Electricity 26-27 (2016), https://perma.cc/RJ33-B8X7.

[98] The Louisiana Public Service Commission's recently adopted net metering reform, which authorizes utilities to recover lost revenues due to excess generation exported to the grid by DER owners, is an especially clear example. Catherine Morehouse, *Louisiana Utilities to Pay Less for Rooftop Solar Power Under New Net Metering Rules*, UtilityDive, Sept. 13, 2019, https://perma.cc/2HGH-B6TL.

[99] Naïm R. Darghouth, Nat'l Renewable Energy Lab., Net Metering and Market Feedback Loops: Exploring the Impact of Retail Rate Design on Distributed PV Deployment 2 (2015), https://perma.cc/53G8-58PK.

[100] Herman K. Trabish, *Renewables: As Rooftop Solar Expands, States Grapple with Successors to Net Metering*, UtilityDive, Sept. 13, 2018, https://perma.cc/FU64-8RXA.

[101] Some states are simply retaining NEM. In Maine, the election of a Democratic Governor and legislature led to the reversal of plans to adopt a NEM replacement that would compensate excess generation based on a static value that reflected avoided utility costs only. Me. Rev. Stat. tit. 35-A, § 3209-A (West 2019) (codifying An Act to Eliminate Gross Metering).

The case for replacing net energy metering with a value stack

If implemented well, a value stack *can* improve on all aspects of NEM without sacrificing the certainty made available from NEM's simplicity. Whereas NEM fails to capture temporal and locational variations in value, a value stack uses them to inform stakeholders and optimize system planning by indicating where DERs can or cannot add value. Whereas NEM ignores values not reflected in retail rates, a value stack can reflect the wider array of values that materially affect stakeholders and system planning. And whereas NEM invites misguided debates over fairness, a value stack can remove the motive and need for such debates by demonstrably compensating program participants for the value they add and nothing more.

It is important to note, however, that a value stack mechanism is an interim and partial solution. The ultimate and complete solution would not stop with owners of DERs but would make the prices that *all* electricity customers pay for electricity services sensitive to costs that change across times and locations. This would level the playing field for investments that can only reduce behind-the-meter consumption such as energy efficiency, and investments that can reduce consumption and inject, such as solar PV. That solution would also expand the list of costs that factor into electricity prices to include emissions of greenhouse gases and ambient air pollutants. However, recognizing that interim steps are often inevitable (if not entirely necessary) to reach this ultimate goal, this report encourages regulators capable of doing so to begin compensating DERs using a value stack. This value stack should reflect temporal and locational differences and encompass more than just avoided utility costs.

NEM and post-NEM programs currently being implemented or considered

1. Retain NEM and ease eligibility limits to allow new categories of participants and larger volumes of participating capacity (example: Washington State).[102]
2. Retain NEM but put curbs on participant compensation (e.g., higher noncoincident demand charges for participants or caps on how much capacity can participate) to (a) offset the revenue utilities lose when DG owners buy less electricity and (b) eliminate cost-shift from participants to non-participants (example: Arkansas).[103]
3. End NEM and adopt a "NEM 2.0" program that employs time-of-use (TOU) rates and locational targeting for program participants (example: California).[104]
4. End NEM (for some or all customer classes) and establish a successor program that credits excess generation based not on retail rates but on a static value that is updated annually (example: Minnesota).[105]
5. End NEM and establish a successor program centered on a value stack whose components are dynamic and whose broad perspective encompasses pollution factors as well as avoided bulk power system and distribution system costs (example: New York).[106]

[102] Wash. Rev. Code Ann. § 80.60.005 (West 2019) (codifying Solar Fairness Act).

[103] Ark. Code Ann. § 23-18-603 through 605 (West 2019). Decision Adopting Successor to Net Energy Metering Tariff, Cal. Pub. Utils. Comm'n Decision 16-01-044 (Jan. 28, 2016), https://perma.cc/DHZ9-U8NW.

[104] Decision Adopting Successor to Net Energy Metering Tariff, Cal. Pub. Utils. Comm'n Decision 16-01-044 (Jan. 28, 2016), https://perma.cc/DHZ9-U8NW.

[105] Minn. Stat. § 216B.164, subd. 10 (West 2019); *see also* Benjamin Norris et al., Clean Power Research (for Minn. Dep't of Commerce), Minnesota Value of Solar: Methodology (Apr. 2014), https://perma.cc/DE53-43R4.

[106] Stanton, *supra* note 4, identifies eight types of response by commissions to the increasingly obvious problems with NEM as the solution for compensating DER contributions to electricity service provision: NEM 2.0 or successor [included VDER]; comprehensive rate design review and update; changing rates for "net excess generation"; higher monthly fixed charges for mass market customers; creation of new DER customer class for separate treatment; authorizing third-party or utility ownership of DERs; authorizing community solar.

Table 7 below summarizes the dynamic components that can be combined by a value stack to inform the value of a DER's contributions—viewed from a societal perspective—to providing electricity services.

Table 7. Value stack components, their underlying dynamic metric(s), and their temporal and locational parameters.

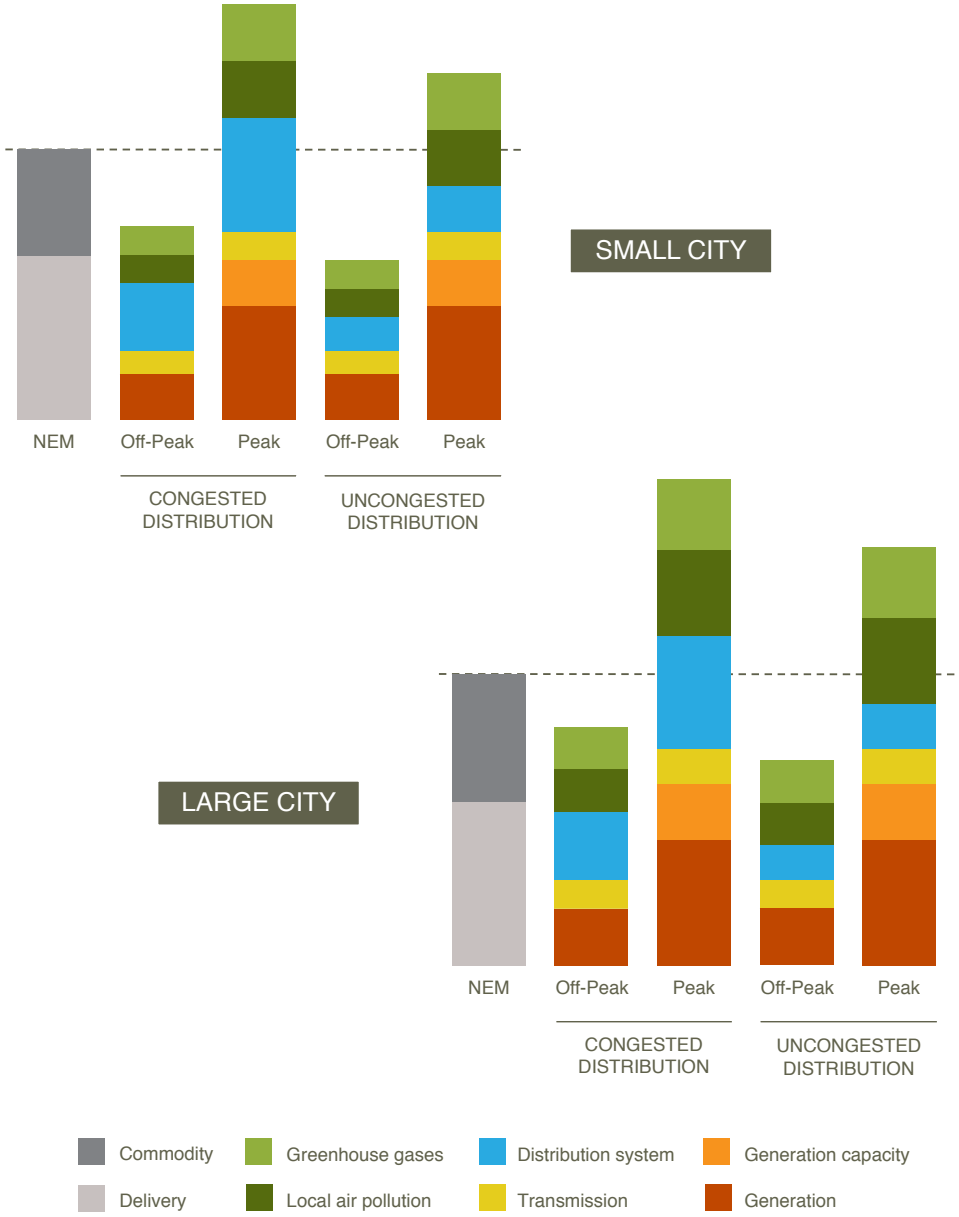
Component	Metric and/or Units	Interval	Geography
Wholesale energy (including generation, congestion, and line losses)	LMP [$/MWh]	Hour	Wholesale market node (or zone)
Wholesale capacity	Installed capacity or "ICAP"[107]	*Varies by jurisdiction*	
Transmission	*Varies by jurisdiction;*[108] *LMP & ICAP capture some but not all capital and O&M costs of transmission*	Six months	
Distribution system capacity and line losses	Utilities' marginal costs of service	Decade	As local as possible: primary feeder, lateral feeder, transformer
Greenhouse gases	[CO_2e / MWh]	Hour	Wholesale market zone
Ambient air pollutants	[PM, SOx, NOx / MWh]	Hour	*As granular as is supported by available tools e.g., EASIUR, InMap*
Resilience	*Varies by jurisdiction*	*Varies by jurisdiction*	Distribution utility service territory

The Metric column contains items described in part II; the Interval column indicates how frequently those metrics should be updated to stay accurate; and the Geography column indicates where the metric pertains. In a "stack," these assembled metrics look like figure 8, below, which shows how they compare to the flat retail rate that informs NEM program compensation.

[107] A California Public Utilities Commission proceeding investigated two different use cases, one for the short term that uses a version of ICAP payments as a proxy for capacity value, and one for the long term that uses the cost of new entry (CONE). *See* Locational Net Benefit Analysis Working Group Long Term Refinements Final Report, Cal. Pub. Serv. Comm'n Rulemaking 14-08-013, at 49-52 (Jan. 9, 2018), https://perma.cc/4JXJ-BYZ8.

[108] *See, e.g.,* ConEdison, Benefit-Cost Analysis Handbook v.2.0, at 20-24 (2018), https://perma.cc/2GPL-5GL3; *see also* Paul Denholm et al., Nat'l Renewable Energy Lab., Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System 34-37 (2014), https://perma.cc/F5XB-W5VH (listing three possible approaches to calculation).

Figure 8. Conceptual comparison of retail rate (and NEM) to value stack compensation across times (peak and off-peak) and locations (congested and uncongested distribution grid sections in a large and small city)



There is an important difference between what the NEM bars indicate and what the others do. The NEM bars' heights indicate what a DER would be compensated by a NEM program in each city over a full billing period. By contrast, the other bars' heights indicate how much a DER would be compensated by a value stack in select places and select times within a billing period.

Figure 8 illustrates how compensation for DERs in accord with this report's proposed value stack would respond to different settings and circumstances. Before exploring how the value stack bars in the figure reflect responses to those settings and circumstances, it is useful to first understand the delivery and commodity components of the NEM bars. As explained above, most retail rates do not reflect the costs of providing electricity services at particular times and locations. Instead, they reflect average values, arrived at by taking the utility's costs of providing electricity in an entire service territory for each billing period, summing those costs and then parceling them out to different classes of ratepayer as "flat" rates. Because NEM mirrors retail rates, NEM generally compensates DER owners based on these homogenized, "flat" values.

This is why, in Figure 8, the delivery component (light grey) in each city is proportionate to the average of the distribution system costs (blue) in the four different settings shown for that city. Even though distribution system costs might be higher in congested areas, the utility does not charge customers served by congested facilities more. And so, NEM compensation does not rise in congested areas or fall where there is no congestion. Similarly, the commodity component (dark grey) of the NEM bars is proportionate to the average of the bulk power system costs (yellow, orange, and red) in the corresponding value stack bars. Even though those costs differ significantly across both congested and uncongested areas and peak and off-peak times, retail rates flatten out these differences. And NEM compensation, which mirrors flat retail rates, ignores those differences too.

Unlike the NEM bar components, the value stack bars' components respond to changes in load (i.e., on- or off-peak), the presence of congestion in the local distribution system, the number of people exposed to air pollution released by nearby generation facilities, and the volume of greenhouse gas pollutants emitted.

Peak/Off-peak. At peak times, the bulk power system incurs costs to generate electricity and transmit it to load centers. And, because enough capacity to supply peak load must be maintained, the bulk power system also incurs capacity costs at peak times. At off-peak times, demand is lower, so energy costs are lower and capacity costs fall to zero. The value stack translates a DER's ability to help avoid costs at these times into commensurate compensation—more at peak times, less at off-peak.

Distribution system congestion. Congestion also makes a distribution system more expensive to operate and can spur expensive capital investments. So, as reflected in the value stack, a DER's ability to help avoid congestion is valuable at all times, and especially at times of peak load. It is important to note that the timing of this congestion may or may not correspond with the bulk power system peak.

City size. The public health costs of local air pollution are a function of the pollution's severity and the number and demographics of people it affects. It follows that those costs are higher in a large city because more people are affected, even if the volume of emissions is the same as that emitted near or in a small city. The value stack compensates a DER for its ability to help avoid these costs.

Greenhouse gas emissions. The generation fleet depicted in Figure 8 resembles those that operate in the NYISO and California ISO. There are no large, coal-fired generators, and the nuclear and renewable resources that supply most generation during off-peak times do not emit. At peak times, especially in cities with constrained transmission access, natural gas and dual-fuel resources operate as well. And so, both the volume of greenhouse gas emissions and the value of DERs' ability to avoid them tracks generation peaks. The large city is home to more load, higher peaks, and thus more emissions. In the PJM Interconnection region—which covers 13 states from the Midwest to the Mid-Atlantic and is home to much of the country's coal-fired generation capacity—these values would be quite different.

Figure 8 makes two important points especially clear. First, the different heights of NEM and value stack compensation in each scenario highlight that NEM programs often ascribe inaccurate values to DERs. Such inaccuracy in NEM-based compensation necessarily leads developers to put DERs in the wrong place, i.e., where they will add little or no value. The second point is that ignoring the costs imposed by emissions—and so ignoring the value of avoiding them—also leads to an under-valuation of DERs. Recognizing DERs' full value requires adopting a broader perspective on costs and benefits than that of a utility and its ratepayers.

Circumstances important to the effectiveness of a value stack

Administering a value stack effectively requires gathering and analyzing a great deal of granular information on an ongoing basis. And it requires regulatory authorities, utilities, and other stakeholders to work together to translate that information—particularly as it relates to various costs—into a single, dynamic price, on an ongoing basis, even as circumstances change. This means deploying AMI and pursuing integrated distribution system planning in a way that balances program design priorities.

When deciding how to compensate DERs, transparency and predictability can be as important as accuracy and precision. The primary goal of the compensation scheme should be the development of the right DERs in the right places, and the avoidance of unnecessary and unduly costly alternatives. Regulators and stakeholders in California and New York have both learned that implementing a value stack in a world rife with transaction costs and risk-aversion requires striking a balance between accuracy, transparency, and predictability.[109] New York's market for solar PV slowed in 2018 after compensation efforts prioritized accuracy without due concern for the other two priorities.[110] That slowdown followed the PSC's Value of Distributed Energy Resources Phase One Implementation Order, which directed that the distribution component of the value stack would be revised every three years based on input from utilities.[111] Investors and the DER developers that rely on them anticipated from this the elimination of revenue for any project beyond a three-year time horizon.[112] Regulators learned from this experience, and in 2019 adjusted the DER compensation scheme by (among other things) "locking in" the distribution component's value for 10 years—the same time horizon used by New York's retail utilities for amortizing distribution grid assets.[113]

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[109] *See* Herman K. Trabish, *Unnecessary Complexity? Assessing New York and California's Landmark DER Proceedings*, UtilityDive, Apr. 4, 2018, https://perma.cc/8N8H-3WGN.

[110] *See* John Weaver, *Community Solar Spurns New York's VDER, Seeks a Return to Net Metering*, PV Mag., June 20, 2018, https://perma.cc/Q9ED-XRKG.

[111] Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters, N.Y. Pub. Serv. Comm'n Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources 11-13 (Sept. 14, 2017), https://perma.cc/52PH-X238.

[112] Jeff St. John, *Why Solar Advocates Are Crying Foul Over New York's Latest REV Order*, UtilityDive, Sept. 19, 2017, https://perma.cc/DM6F-3YZL; see also Comments of the Clean Energy Parties, N.Y. Pub. Serv. Comm'n Case 15-E-0751, Value of Distributed Resources Phase One Implementation Plans 5 (July 24, 2017), https://perma.cc/2VU7-ZCWY ("It is much harder to design customer products and finance projects if there are key values that are unpredictable, irretrievable, or subject to utility interpretation.").

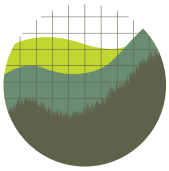
[113] Order on Value Stack Compensation, N.Y. Pub. Serv. Comm'n Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources 20-21 (Apr. 18, 2019), https://perma.cc/8NBD-FVKP.

Conclusion

The value of particular electricity resources to different stakeholders and to society as a whole depends on multiple factors, several of which are sensitive to where and how those resources operate. For instance, in a region where load growth is on pace to exceed the capacity of existing generation or transmission, DERs whose operation will reduce load peaks can help to defer or wholly avoid the costs of importing more electricity from other regions or developing new generation and transmission facilities. Similarly, in an area burdened by a congested distribution system, DERs that alleviate one or more sources of congestion can thereby reduce costs and, potentially, improve reliability. And DERs located in communities served by fossil-fueled generation facilities can displace those facilities' operation and thereby deliver environmental and public health benefits. If the displaced facilities burn coal or oil, the benefits of their displacement are likely to be especially large. Capturing these sorts of benefits requires adopting a perspective that recognizes them. Such a perspective must be broader than that of an electric utility and should be broad enough to recognize benefits and costs accruing to society as a whole, such as the benefits to public health of avoiding local pollution.

NEM programs generally do a poor job of translating these determinants of value into appropriate compensation for DERs. This deficiency owes to NEM programs' embodiment of a cramped perspective (that of a utility, rather than society) and reliance on flat retail rates that ignore the importance of timing and location to value. State regulators considering how best to compensate DERs should make those two features—a broad perspective on benefits and costs, and sensitivity to timing and location—basic to whatever programs they adopt. A value stack is the logical mechanism for translating these features into compensation for DERs, and thereby informing decisions about whether solar PV, energy storage, another type of DER, or no DER at all would add the most value in a given set of circumstances.

As several states have discovered, implementing a value stack requires commissions to strike a balance between the competing priorities of accurate valuation, transparent access to information about the local and regional electricity grid, and predictability with regard to sources of DER compensation. All three are indispensable, and ensuring that a DER compensation program embodies all three requires thoughtful engagement with stakeholders both before and after a commission adopts a value stack. Commissions just now undertaking to examine and possibly move beyond their NEM programs should look to both the processes and the outcomes in states that have led, even if they have sometimes stumbled along the way.



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