ON THE PATH TO SUNSHOT

Utility Regulatory and Business Model Reforms for Addressing the Financial Impacts of Distributed Solar on Utilities

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Preface

The U.S. Department of Energy launched the SunShot Initiative in 2011 with the goal of making solar electricity cost-competitive with conventionally generated electricity by 2020. At the time this meant reducing photovoltaic and concentrating solar power prices by approximately 75%—relative to 2010 costs—across the residential, commercial, and utility-scale sectors. To examine the implications of this ambitious goal, the Department of Energy's Solar Energy Technologies Office (SETO) published the *SunShot Vision Study* in 2012. The study projected that achieving the SunShot price-reduction targets could result in solar meeting roughly 14% of U.S. electricity demand by 2030 and 27% by 2050—while reducing fossil fuel use, cutting emissions of greenhouse gases and other pollutants, creating solar-related jobs, and lowering consumer electricity bills.

The *SunShot Vision Study* also acknowledged, however, that realizing the solar price and deployment targets would face a number of challenges. Both evolutionary and revolutionary technological changes would be required to hit the cost targets, as well as the capacity to manufacture these improved technologies at scale in the U.S. Additionally, operating the U.S. transmission and distribution grids with increasing quantities of solar energy would require advances in grid-integration technologies and techniques. Serious consideration would also have to be given to solar siting, regulation, and water use. Finally, substantial new financial resources and strategies would need to be directed toward solar deployment of this magnitude in a relatively short period of time. Still the study suggested that the resources required to overcome these challenges were well within the capabilities of the public and private sectors. SunShot-level price reductions, the study concluded, could accelerate the evolution toward a cleaner, more cost-effective and more secure U.S. energy system.

That was the assessment in 2012. Today, at the halfway mark to the SunShot Initiative's 2020 target date, it is a good time to take stock: How much progress has been made? What have we learned? What barriers and opportunities must still be addressed to ensure that solar technologies achieve cost parity in 2020 and realize their full potential in the decades beyond?

To answer these questions, SETO launched the *On the Path to SunShot* series in early 2015 in collaboration with the National Renewable Energy Laboratory (NREL) and with contributions from Lawrence Berkeley National Laboratory (LBNL), Sandia National Laboratories (SNL), and Argonne National Laboratory (ANL). The series of technical reports focuses on the areas of grid integration, technology improvements, finance and policy evolution, and environment impacts and benefits. The resulting reports examine key topics that must be addressed to achieve the SunShot Initiative's price-reduction and deployment goals. The *On the Path to SunShot* series includes the following reports:

- Emerging Issues and Challenges with Integrating High Levels of Solar into the Electrical Generation and Transmission Systems (Denholm et al. 2016)

- Emerging Issues and Challenges with Integrating High Levels of Solar into the Distribution System (Palmintier et al. 2016)

- Emerging Opportunities and Challenges in Financing Solar (Feldman and Bolinger 2016)

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

- Utility Regulatory and Business Model Reforms for Addressing the Financial Impacts of Distributed Solar on Utilities (Barbose et al. 2016)

- The Role of Advancements in Photovoltaic Efficiency, Reliability, and Costs (Woodhouse et al. 2016)

- Advancing Concentrating Solar Power Technology, Performance, and Dispatchability (Mehos et al. 2016)

- Emerging Opportunities and Challenges in U.S. Solar Manufacturing (Chung et al. 2016)

- The Environmental and Public Health Benefits of Achieving High Penetrations of Solar Energy in the United States (Wiser et al. 2016).

Solar technology, solar markets, and the solar industry have changed dramatically over the past five years. Cumulative U.S. solar deployment has increased more than tenfold, while solar's levelized cost of energy (LCOE) has dropped by as much as 65%. New challenges and opportunities have emerged as solar has become much more affordable, and we have learned much as solar technologies have been deployed at increasing scale both in the U.S. and abroad. The reports included in this series, explore the remaining challenges to realizing widely available, cost-competitive solar in the United States. In conjunction with key stakeholders, SETO will use the results from the *On the Path to SunShot* series to aid the development of its solar price reduction and deployment strategies for the second half of the SunShot period and beyond.

Acknowledgments

List of Acronyms

ACC	Arizona Corporation Commission
ACEEE	American Council for an Energy-Efficient Economy
APPA	American Public Power Association
APS	Arizona Public Service
BNEF	Bloomberg New Energy Finance
CAISO	California Independent System Operator
COS	cost-of-service
CPUC	California Public Utilities Commission
DER	distributed energy resources
DG	distributed generation
DGIP	Distributed Generation Interconnection Plan
DOE	U.S. Department of Energy
DPU	department of public utilities
DPV	distributed photovoltaics
DRP	distributed resources plan
DSO	distribution system operator
DSP	distribution service provider
DSPP	distribution service platform provider
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESU	Energy Services Utility
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
FiT	feed-in tariff
GS	general service
GSD	general service demand
GTM	Greentech Media
GW	gigawatt(s)
HECO	Hawaiian Electric Company
IDP	Integrated Distribution Planning
IDSO	Independent Distribution System Operator
IOU	investor-owned utility
IREC	Interstate Renewable Energy Council
ISO	independent system operator
ITC	investment tax credit
kW	kilowatt
kWh	kilowatt-hour
LRAM	lost-revenue adjustment mechanism
LSE	load-serving entity
MISO	Midcontinent Independent System Operator, Inc.
MW	megawatt(s)
NEM	net energy metering
NPV	net present value
NREL	National Renewable Energy Laboratory

PBR	performance-based regulation
PG&E	Pacific Gas & Electric
PSCo	Public Service Company of Colorado
PUC	public utility commission
PV	photovoltaic(s)
REC	renewable energy certificate
ReEDS	Regional Energy Deployment System model (NREL)
REV	Reforming the Energy Vision initiative (New York)
RIIO	Revenue = Incentives + Innovation + Outputs
RIM	Ratepayer Impact Measure
RMP	Rocky Mountain Power (Utah)
ROE	return on equity
RPS	renewable portfolio standard
RSWG	Reliability Standards Working Group (Hawaii)
RTO	regional transmission organization
RTP	real-time pricing
SAM	System Advisor Model (NREL)
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SEIA	Solar Energy Industries Association
SPVTOU	Secondary PV Time-of-Use rate (PSCo)
SRP	Salt River Project
T&D	transmission and distribution
TEP	Tucson Electric Power
TOU	time-of-use
TPO	third-party ownership
VoS	Value of Solar (tariff)

Executive Summary

Net-energy metering (NEM) with volumetric retail electricity pricing has enabled rapid proliferation of distributed photovoltaics (DPV) in the United States. However, this transformation is raising concerns about the potential for higher electricity rates and cost-shifting to non-solar customers, reduced utility shareholder profitability, reduced utility earnings opportunities, and inefficient resource allocation. Although DPV deployment in most utility territories remains too low to produce significant impacts, these concerns have motivated real and proposed reforms to utility regulatory and business models, with profound implications for future DPV deployment.

This report explores the challenges and opportunities associated with such reforms in the context of the U.S. Department of Energy's SunShot Initiative. As such, the report focuses on a subset of a broader range of reforms underway in the electric utility sector. Drawing on original analysis and existing literature, we analyze the significance of DPV's financial impacts on utilities and non-solar ratepayers under current NEM rules and rate designs, the projected effects of proposed NEM and rate reforms on DPV deployment, and alternative reforms that could address utility and ratepayer concerns while supporting continued DPV growth. We categorize reforms into one or more of four conceptual strategies (Table ES-1). Understanding how specific reforms map onto these general strategies can help decision makers identify and prioritize options for addressing specific DPV concerns that balance stakeholder interests.

Table ES-1. Strategies to Address Concerns about the Utility Financial Impacts of DPV

Strategies	Stakeholder Concerns Addressed		
	Increased Retail Rates and Cost-Shifting	Reduced Utility Shareholder Return on Equity	Reduced Utility Earnings Opportunities
Reduce compensation to DPV customers Key examples: NEM and retail rate reforms, community solar (potentially)	✔	✔	✔
Facilitate higher-value DPV deployment Key examples: time-varying, locational, or unbundled attribute pricing; enhanced utility system planning, utility ownership and financing of DPV, community solar, distribution network operators, services-driven utilities	✔	✔	
Broaden customer access to solar Key examples: utility ownership and financing of DPV, community solar	✔		
Align utility profits and earnings with DPV Key examples: Decoupling and other ratemaking reforms to reduce regulatory lag, utility ownership and financing of DPV, performance-based incentives, distribution network operators, services-driven utilities		✔	✔

Reducing compensation to DPV customers. Recent efforts to address stakeholder concerns about the impacts of DPV have revolved largely around reforms to NEM rules and retail rate structures. These include, for example: new or increased charges for DPV customers, minimum bills, demand charge rates for DPV customers, reduced compensation for electricity exported to the grid, reduced compensation for all DPV generation under two-way rates, and transfer of renewable energy certificate ownership to the utility. Although such reforms can address the concerns of both utility shareholders and non-solar customers and are often relatively straightforward to implement compared to more fundamental reforms to utility business models or markets, they accomplish their objectives only by constricting DPV customer-economics and deployment. They are thus largely a zero-sum game. Community solar is one possible exception because its economies of scale may allow for compensation at prices below retail rates, while maintaining customer-economics comparable to rooftop DPV with full NEM.

To demonstrate the deterioration in DPV customer-economics that could occur if, in particular, NEM were eliminated, we compare the payback period of DPV systems with and without NEM, based on original analysis described further within the main body of the report. In the latter case, we assume that DPV generation exported to the grid in each hour is compensated at wholesale electricity prices, rather than at retail rates. As shown in Figure ES-1, elimination of NEM would increase the payback period for residential DPV systems by 1.4–8.9 years across the six illustrative states shown, depending on the state and the size of the system. Elimination of NEM would erode the customer-economics of commercial DPV as well, though only in cases where significant grid exports occur and where volumetric rates under the prevailing retail electricity tariff are substantially above wholesale electricity prices. As other studies have shown, customer-sited storage and demand flexibility can help DPV customers insulate themselves from such changes, though in doing so would also thwart the effort to stem utility revenue erosion.
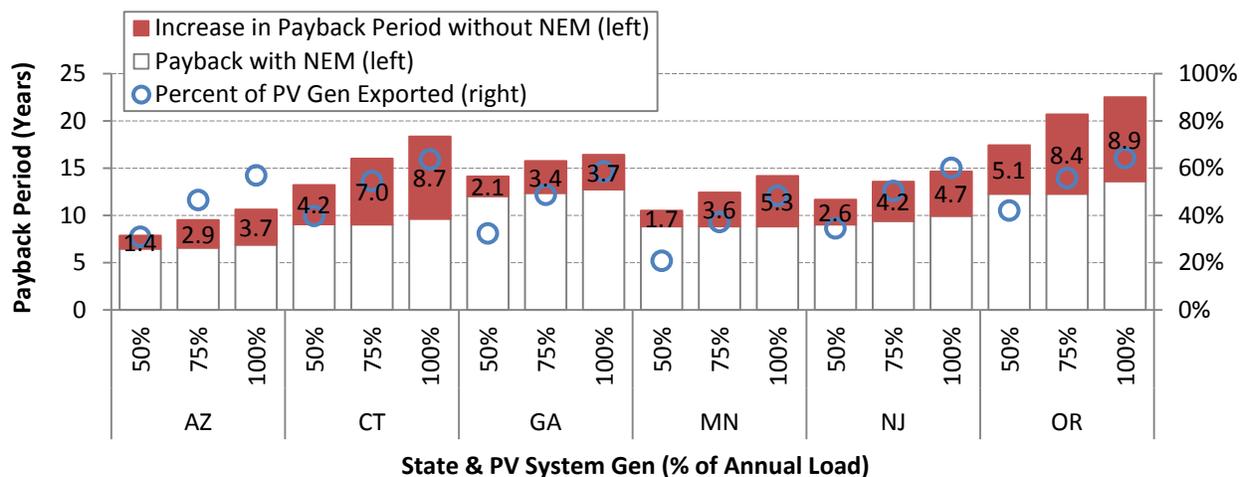
Figure ES-1. Impact of NEM elimination on residential PV payback period

Given the implications for DPV customer-economics, reforms to NEM rules could also significantly impact long-term DPV deployment levels. Under an extreme bookend scenario in which NEM is immediately eliminated across all states and replaced with the alternative compensation scheme described above, cumulative U.S. DPV deployment in 2050 would be roughly 20% lower than under a continuation of current NEM policies (Figure ES-2, left), based on original analysis described further within the main body of the report. Conversely,

indefinitely extending and expanding NEM to all customers and states would lead to DPV deployment levels in 2050 that are 30% higher than under current policies (Figure ES-2, right). In both cases, the impacts are notably more pronounced for residential than for non-residential markets. Many other recent studies have also shown potentially significant impacts on DPV customer-economics and deployment from other kinds of retail rate reforms, such as time-varying pricing, demand charges, two-way rates, fixed customer charges, and minimum bills.
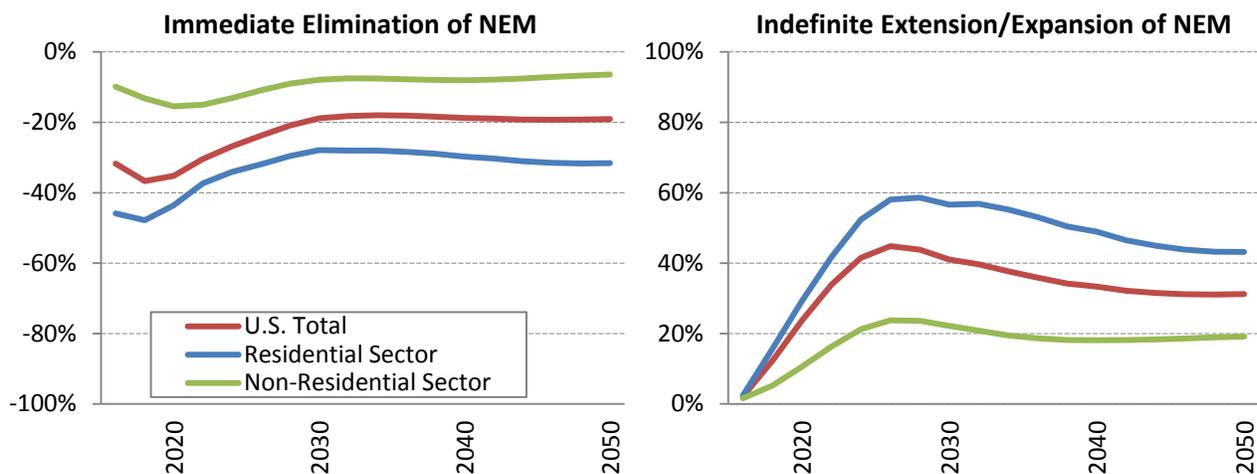
Figure ES-2. Projected change in cumulative DPV capacity under NEM reforms compared to deployment under current NEM policies

Within the context of the SunShot Initiative, NEM and retail rate reforms represent significant risks to achievement of near-term cost and deployment goals as well as the longer-term legacy and impact of the initiative. Within the immediate timeframe of the SunShot 2020 cost-reduction targets, constraints on market growth could dampen the pace of soft-cost reductions driven by increasing industry scale and learning. Uncertainty in the outcome of NEM and retail rate reforms also exacerbates business risks for the solar industry and potential solar customers, inflating soft costs associated with customer acquisition and financing. Longer term, NEM and retail rate reforms could produce an outcome in which achievement of the aggressive SunShot 2020 cost targets could still fail to spur the initiative's vision of dramatic, sustained DPV growth.

Fortunately, several other strategies—as discussed below—offer the potential to address utility and non-solar customer concerns about DPV, without unduly constraining DPV customer-economics and market growth.

Facilitating higher-value DPV deployment. Many reforms seek to address stakeholder concerns about DPV by facilitating higher-value DPV deployment. Certain retail rate reforms—such as time-varying, locational, and unbundled attribute pricing—could incentivize optimally sited and grid-friendly DPV, though these innovations generally increase costs to DPV customers and could require significant efforts from utilities to establish the value of DPV production and handle customer differentiation. Enhanced utility system planning can provide an analytical foundation for these pricing designs and for other mechanisms to preferentially direct DPV deployment toward locations or design characteristics that increase its value to the utility system. In addition, utility ownership of DPV assets may enable higher-value forms of deployment through optimized siting and operation. Community solar might also facilitate optimized siting and design and more

readily enable deferral of distribution system upgrades. Over the longer term, major reforms to utility business models and retail markets (e.g., transforming electric utilities into energy services utilities and forming distribution network operators or transactive retail electricity markets) could facilitate higher-value DPV deployment through enhanced price signals or procurement processes.

Broadening customer access to solar. Bringing solar to traditionally underserved customer classes can diffuse concerns about cost-shifting and potentially regressive effects of NEM; indeed, one reason why energy efficiency programs are less susceptible to such concerns is that opportunities for participation are broad and often include programs targeted to low-income or other hard-to-reach customer segments. Among the reforms highlighted in this report, community shared solar offers perhaps the most explicit path toward expanding customer access, if opportunities for participation are broadly available. Utility DPV ownership that is restricted to underserved customer segments may provide another pathway to expanding access to those customers, and it may minimize some objections over utility entry into a competitive market.

Aligning utility earnings and profits with DPV. Under traditional cost-of-service regulation, DPV tends to erode utility financial performance via reductions in sales growth and deferral of traditional utility capital investments. Reforms can seek to realign utility financial incentives so they are neutral toward, or even produce utility shareholder benefits from, DPV growth. Such reforms are thus targeted at addressing utility shareholder concerns, in particular, but can exacerbate ratepayer concerns surrounding possible cost-shifting to non-solar customers. Some suggested reforms entail relatively "incremental" changes to utility regulatory and business models. These include decoupling and other ratemaking reforms to reduce regulatory lag, which already have widespread adoption and hold utility profits immune to DPV growth. Performance-based incentives and utility ownership or financing of DPV assets could create positive utility earnings opportunities associated with DPV growth, and they have precedents, but they represent a greater departure from the traditional cost-of-service model. Finally, many novel conceptual utility business model and market reforms are intended to realign utility financial incentives vis-à-vis DPV, such as by reorienting utility profits around the provision of services rather than commodity sales of electricity.

In summary, efforts to address concerns by utilities and non-solar customers about the financial impacts of DPV growth are unfolding across the country in a variety of forms. To date, much of this activity has centered on reforms to NEM rules and retail rate designs. This pathway has certain practical advantages because these kinds of reforms address concerns of both utility ratepayers and shareholders and can often be implemented in a relatively immediate fashion. However, these reforms are generally premised on reducing compensation to DPV customers and, as such, achieve their objectives only insofar as they constrict DPV customer-economics. Other reforms discussed in this report instead provide opportunities to address utility and/or ratepayer concerns about DPV without necessarily constraining growth of those resources—by focusing on facilitating higher-value DPV deployment, expanding customer access, and aligning utility earnings and profits with DPV growth. Some of these alternatives have already been adopted in some locations and are options for wider implementation by 2020, while others will unfold over a longer horizon. In either case, opportunities exist to preserve the long-term legacy of the SunShot Initiative by promoting a stable regulatory environment and utility business models that align DPV adoption with the continued provision of safe, reliable, and affordable electricity service.

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1 Introduction

It has become a truism that the U.S. electric utility industry is in the midst of unprecedented transformation. Although the causes and aspects of this transformation are many, one central theme is the rapid growth of distributed energy resources (DERs) and the resulting concerns, expressed by utilities and others, about utility revenue shortfalls and cost-shifting between customers adopting DERs and others. These concerns have, in turn, motivated an ever-expanding set of discussions about reforms of utility regulatory and business models. Such reforms cover a vast terrain: from incremental changes to existing rate structures and net energy metering (NEM) rules, to more-significant structural changes to retail electricity pricing and the ways utilities collect revenues, to fundamental changes in the role utilities play in electricity markets and how they interact with customers and other market participants.

The outcome of these reforms will undoubtedly have profound implications for the solar sector. Within the specific context of the U.S. Department of Energy's SunShot Initiative, the implications are several-fold. In the near term, potential reforms to NEM rules and retail electricity rates for distributed photovoltaic (DPV) customers could significantly impair the initiative's ability to reach its 2020 cost-reduction and deployment targets. As has been repeatedly and convincingly demonstrated, cost reductions for DPV derive, to a significant degree, from increasing experience and scale within the industry (Hoff et al. 2010; Schaeffer et al. 2004; Shrimali and Jenner 2013; van Benthem et al. 2008). Reaching the SunShot 2020 cost targets will require rapid market growth to continue through the remainder of the decade. Yet the proliferation of proposals to eliminate NEM and revise retail electricity tariffs for DPV customers could undercut the economics of DPV and dampen solar deployment over the coming years, especially in concert with the contraction of other key incentives and forms of policy support. In addition to delaying or impeding cost reductions from industry scale and learning, uncertainty surrounding NEM and retail rates can also impose real and direct costs—increasing soft costs associated with customer acquisition and financing as well as undermining orderly, efficient industry growth.

In the longer term, the implications of utility regulatory and business model reforms for the SunShot Initiative are more open ended. On the one hand, changes to NEM rules and retail rates—even if they do not significantly undermine achievement of the 2020 cost targets—could have dramatic impacts on DPV deployment levels over the following decades. Reaching the initiative's 2020 cost targets will no doubt be a great achievement, but it would be a victory in name only if those dramatic cost reductions do not translate into high levels of solar adoption. The long-term SunShot legacy will therefore require not only continued cost reductions but also a stable regulatory environment and set of utility business models that align expanded adoption of DPV with the continued provision of safe, reliable, and affordable electricity service.

Fortunately, various reforms that could facilitate this alignment are already under consideration. These include—but are not limited to—decoupling and other mechanisms for reducing regulatory lag; performance-based regulation (PBR) and incentives; enhanced utility system planning; utility ownership or financing of DPV assets; shared solar; and a variety of broader market and business model reforms, such as the formation of distribution network operators, services-driven utilities, and transactive energy. Discussions about many of these kinds of reforms are already underway, both within the industry at large and in specific states, but have

yet to coalesce around any core set of strategies. Although the full effects of these efforts will likely unfold beyond the immediate time horizon of the SunShot Initiative, opportunities exist today and in the coming years to inform these efforts and ensure that achievement of the SunShot cost targets yields long-term benefits by driving DPV deployment over the decades ahead.

This report provides a snapshot (as of year-end 2015) and synthesis of ongoing discussions surrounding reforms to utility regulatory and business models that may address the financial impacts of distributed PV on electric utilities, specifically highlighting the challenges and opportunities these reforms represent with respect to the SunShot goals. Drawing on a combination of original analysis and existing literature—literature that represents a diversity of perspectives and has collectively undergone broad external review—we address these key questions:

- How significant are the financial impacts that DPV might impose on utilities and non-solar ratepayers under current NEM rules and rate designs?

- How would proposed revisions to NEM rules and retail electricity rates affect the economics and deployment of DPV over the near and longer terms?

- What alternative approaches could address concerns about the financial impacts of DPV on utilities and non-solar customers while supporting robust solar deployment?

Each of these questions is addressed through a synthesis of existing literature, as well as original analysis that further explores aspects of the second question above. In addressing these questions, we focus primarily on reforms associated with provision of retail electricity service, and thus we concentrate on the residential and commercial photovoltaic (PV) sectors. Other reports within the *On the Path to SunShot* series address complementary topics, including the integration of utility-scale solar into bulk power markets, the physical impacts and integration of DPV into distribution networks, and innovations in solar financing and product offerings.

The remainder of the report is organized as follows. Section 2 addresses those reforms that pose the greatest challenges for continued DPV deployment—namely, revisions to NEM rules and rate design reforms involving increased fixed or demand charges for DPV customers. We describe the stakeholder concerns motivating these reforms, review the available analysis on the potential magnitude of these concerns, and provide an overview of the range of NEM and rate design reforms under consideration. Then, in Section 3, we quantitatively estimate the potential impact of NEM and retail rate reforms on DPV economics and deployment. Those estimates are based partly on analyses using the National Renewable Energy Laboratory's (NREL's) System Advisor Model (SAM) and dSolar deployment model as well as a review of previously published studies. Next, in Section 4, we discuss a broader range of utility regulatory and business model reforms that may offer opportunities to address stakeholder concerns about the financial impacts of DPV on utilities and non-solar customers in ways that are compatible with continued DPV deployment. Finally, in Section 5, we conclude by proposing a framework to help decision makers prioritize options for aligning increased DPV deployment with utility shareholder and ratepayer interests.

2

2 Net Metering and Rate Design Reforms

NEM, in combination with volumetric retail electricity pricing, is often cited as a key driver for the rapid growth of DPV in the United States, especially in the residential sector (SEIA 2013). This relatively simple arrangement allows customers with DPV installed behind the meter to, in effect, receive compensation for each unit of electricity generated by their systems at a price often equal to the all-in cost of retail electricity service. This has enabled especially high levels of DPV growth in states—such as California, Hawaii, and Arizona—with high retail electricity prices, steeply inclining block rates, and/or high levels of solar radiation. More broadly, the combination of NEM and volumetric retail electricity pricing has been a key component of the overall customer-value proposition, in concert with federal tax incentives, state or utility incentive programs, and innovations in customer financing options.

With this success have come corresponding concerns about the effects on non-solar customers and on utilities' ability to deliver attractive shareholder returns. Although often voiced by utilities or their representatives (Borlick and Wood 2014; Kind 2013), such concerns have been expressed by many other entities as well, including various financial analysts and utility management consultants (Accenture 2014; Baker et al. 2014; Deloitte 2012; Dumoulin-Smith et al. 2013; Goldman Sachs 2013; ScottMadden Consultants 2013), research institutions (MIT 2015), and consumer advocates (CPUC 2015e). The same fundamental concerns about utility revenue erosion and cost-shifting from participants to non-participants have also long been raised in connection with energy efficiency programs and other forms of DERs (Eto et al. 1994; Harrington et al. 1994; Kushler et al. 2006; Moskovitz 2000; NAPEE 2007; Stoft et al. 1995; Wiel 1989), albeit often not with the same level of alarm.

In response to these concerns, states and utilities are considering various potential actions, ranging from incremental changes in rate design to a fundamental rethinking of the structure of retail energy markets and utility business models. In this section, we focus narrowly on one subset of the potential set of responses—namely, reforms to NEM and retail electricity rate design, which in most instances would tend to impose challenges for the DPV market and achievement of the SunShot goals. We begin by clarifying the nature of the concerns that are motivating efforts to reform NEM and retail rates for DPV customers. We then review the body of empirical and analytical work characterizing the potential magnitude of these concerns. Drawing in part on other recent summaries, we then briefly characterize the breadth of NEM and retail rate reforms currently under consideration. The following section then assesses how those reforms might impact DPV customer-economics and deployment as well as what those impacts would mean for achieving the SunShot goals.

2.1 Understanding the Nature of Stakeholder Concerns

Although sometimes reduced to simple statements about DPV customers "not paying their fair share," stakeholders' concerns are more varied and complex, including at least the following:

- **Increased retail rates and cost-shifting:** DPV with NEM reduces utility sales, resulting in a loss of revenues. At the same time, DPV also reduces utility costs, though wide disagreements exist about the magnitude and sources of those cost savings (e.g., whether they include only avoided fuel and power-purchase costs or also avoided utility capital expenditures). To the extent that revenue reductions exceed cost savings, average retail

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rates will tend to rise to ensure the utility has the opportunity to recover its costs, shifting costs onto non-solar customers. This balance between reductions in revenues and costs, and any associated rate impacts and cost-shifting, may vary over time—for example, because of the periodic deferral of large capital investments.

- **Lower utility shareholder return on equity (ROE):** Although some utility costs are directly passed through to customers via fuel-adjustment clauses and other surcharges, many other costs are recovered through rates established through periodic rate cases. Depending on the customer class, rates may consist primarily of volumetric charges. As a result, reductions in sales associated with DPV reduce revenues from base rates in between rate cases, absent decoupling or other similar mechanisms. To the extent those revenue reductions exceed the associated cost savings, they may reduce utility shareholder ROE. Over the long term, reduced utility shareholder returns may challenge the utility's ability to raise capital. These effects have an analogue in bulk power markets, where high penetrations of renewable energy can similarly erode the revenues and profitability of incumbent generators, as described in Text Box 1.

- **Reduced utility earnings opportunities:** Traditionally, regulated utilities generate earnings from capital investments in generation, transmission, and distribution infrastructure. To the extent that DPV avoids or defers these traditional utility capital investments, it will erode utility earnings opportunities, though those lost earnings may be offset to some extent by network upgrades to integrate DPV. Also important to note is that capital investments by utilities create value for their shareholders only if the achieved ROE on those incremental investments are greater than the underlying cost of equity (Koller et al. 2010); thus, reduced utility earnings as a result of DPV-induced capital deferrals represent a loss of shareholder value only if achieved ROE is greater than the underlying cost of equity.

- **Inefficient allocation of resources:** Volumetric retail electricity rates may correspond poorly to the marginal cost of producing and delivering electricity. That mismatch can extend in either direction and can vary by time and location. In the specific example of NEM, customers may be either over- or under-incentivized to install DPV, depending on the scope of costs considered, or may not be incentivized to install DPV in the most valuable manner (e.g., in terms of location, size, orientation, etc.). Questions or concerns about inefficient price signals for DPV may arise within the context of utility ratemaking processes, but they are perhaps more central to broader policy discussions about how best to achieve particular policy goals, such as grid modernization or reduction of greenhouse gas emissions.

Text Box 1. Revenue Adequacy Concerns in the Bulk Power Market

Renewable generation with a low marginal cost of energy displaces higher-marginal-cost generation in wholesale power markets, an impact sometimes referred to as the merit-order effect (Sensfuß et al. 2008). In the short run—that is, within the time it takes new generation to be built or existing generation to retire—this shifting of the supply curve reduces market clearing prices, as more-expensive units are no longer needed to meet demand in hours with renewable generation. Lower wholesale market prices can then reduce generators' net revenue. Expectations of lower net revenues, in turn, can inform longer-term investment decisions, leading to delays in new generation capacity and accelerated retirement of existing capacity.

The impact of renewables on the net revenues of other generation can be important to considerations about resource adequacy, carbon intensity, and integration of variable generation. For example, the effect of wind energy on lowering wholesale prices is often cited as one factor behind reductions in net revenue at nuclear plants, some of which have announced early retirements. Simulation studies confirm the potential for high penetrations of renewables to reduce the net revenue for various generator types. For example, Traber and Kemfert (2011) forecast reductions in net revenue for generation in Germany in scenarios with increasing wind. Ela et al. (2014) analyze results from the Western Wind and Solar Integration Study and find that net revenues for nuclear, coal, and combined-cycle units decrease the most with increased shares of wind and solar.

Various proposals have been put forward to address revenue adequacy issues that may occur under high penetrations of renewables, at least for some subset of affected units. One solution is simply to allow units to retire as net revenue falls: the reality of wholesale markets is that some generation will not be competitive as new sources are introduced. One other solution is to encourage utilities to sign long-term contracts with plants to ensure adequate revenues to keep those plants operating. Other possible options include various reforms to existing market mechanisms, such as raising scarcity prices in "energy-only" market designs, introducing flexibility requirements into resource adequacy obligations that require loads to have contracts with sufficient resources to meet their peak needs, and improving forward capacity markets. In addition, the California Independent System Operator (CAISO) and the Midcontinent Independent System Operator (MISO) have both introduced flexible ramping products into the design of their wholesale energy markets to improve pricing signals for flexible resources.

These reforms to wholesale markets do not directly impact deployment of solar, though they can enable solar market growth by ensuring adequate flexible generation will be available to maintain reliability. In the future, reforms such as obligations to procure flexible generation may increase incentives for solar to add dispatchability capabilities, as with solar-plus-storage.

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2.2 What Is the Magnitude of DPV's Impacts on Utility Shareholders and Ratepayers? Reviewing the Evidence and Analysis to Date

The financial impacts of DPV on utility shareholders and ratepayers derive in large measure from the associated reduction in retail electricity sales and growth. As shown in the left-hand panel of Figure 1, electricity generation from all DPV systems installed through the end of 2014 reduced retail electricity sales by less than 2% in all states other than Hawaii, and reductions were less than 0.4% of retail sales in all states outside of the top 10.[1] Nationally, cumulative DPV installations through 2014 represented 0.3% of total U.S. retail electricity sales. To be sure, impacts on residential sales are proportionally larger, as shown in the right-hand panel of Figure 1. Impacts on residential sales are by far the most pronounced in Hawaii, where DPV reduced residential sales by more than 13% in 2014 (compared to a reduction in total retail electricity sales of roughly 6%). Nevertheless, outside of Hawaii and a handful of other states, DPV reduced residential electricity sales by less than 1% in the vast majority of states and by just 0.4% nationally. Thus, for the vast majority of states, the financial impacts of DPV on utilities and their ratepayers are likely "well within the noise" today, given the many other drivers also impacting retail electricity sales.

Concerns expressed by many utilities may be more anticipatory in nature, however, given the rapid growth of DPV in some states and the prospect for broader market uptake as costs continue to fall.[2] Under the 2020 forecasts developed by GTM Research (2015) in late 2015 (following extension of the federal investment tax credit), residential DPV penetration would reach an estimated 2.9% of total U.S. residential retail electricity sales in 2020 and would surpass 5% of retail sales in ten states—with California and Hawaii reaching roughly 34% and 53%, respectively.[3] Naturally, looking further out in time would yield even higher penetration levels. For example, simply assuming that DPV growth during 2020–2030 continues at the same pace as GTM and SEIA project for the year 2020, electricity generation from residential DPV in 2030 would reach 9.5% of total U.S. residential electricity sales and would surpass 10% of residential sales in 16 states. Under this hypothetical extrapolation, residential DPV generation in California, Hawaii, and Vermont would actually exceed total retail electricity sales; that is, the majority of residential electricity consumption would be self-supplied. In contrast, EIA's 2015 *Annual Energy Outlook* forecasts that generation from residential DPV will reach only 1.4% of total U.S. residential electricity sales by 2030 (compared to the 9.5% derived by extrapolating GTM's forecast through 2020). Thus, some significant degree of uncertainty exists about whether and when future DPV penetration—outside of several high-penetration states—will actually reach levels warranting significant concern.

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[1] The values in Figure 1 were derived based on data for residential and commercial PV capacity published by GTM Research and the Solar Energy Industries Association (GTM Research and SEIA 2015), in concert with U.S. Energy Information Administration (EIA) data for retail electricity sales (EIA 2015a). Generation was estimated from capacity data using PVWatts, based on a representative city in each state, assuming south-facing panels with a 0.77 direct current-to-alternating current de-rate (the default assumption in PVWatts).

[2] Current concerns may also anticipate the potentially significant lead time required to institute reforms and the increasingly political difficulty in reforming existing DPV compensation mechanisms the longer they are in place.

[3] Projected penetration levels are calculated from retail electricity sales projections in EIA's 2015 *Annual Energy Outlook*, adjusting for the difference between DPV growth projected by GTM/SEIA and EIA's forecast of DPV growth in each region (EIA 2015b). For Hawaii, we instead use the load forecast from Hawaiian Electric Companies' 2013 integrated resource plan (Hawaiian Electric Companies 2013) and make a similar adjustment based on the difference between underlying DPV growth assumed in that forecast and the GTM/SEIA forecast.

Total DPV Penetration
Percent of Total Statewide Retail Electricity Sales

Residential DPV Penetration
Percent of Residential Retail Electricity Sales
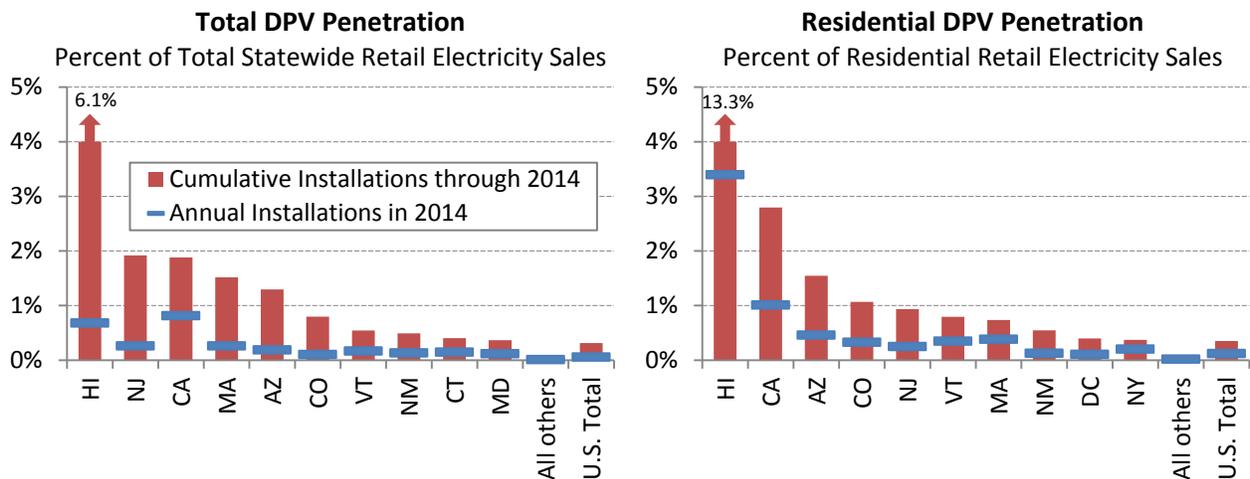
Figure 1. Current DPV impacts on retail electricity sales
Data sources: GTM Research and SEIA 2015; EIA 2015a

Utility concerns about DPV are likely amplified by the simultaneous growth in energy efficiency, which similarly erodes electricity sales and leads to many of the same concerns about cost-shifting and utility profitability. In fact, by most measures and in all but a few U.S. utility service territories, the impacts of energy efficiency on utility sales (both programmatic and naturally occurring) have been far greater than those of DPV. Energy efficiency programs implemented over the past two decades have reduced current U.S. retail electricity sales by roughly 4.3%.[4] This is roughly 15 times larger than the cumulative impact from all DPV systems installed through 2014 (0.3% of U.S. retail sales, as noted previously). Looking at just the incremental impacts in a single year, energy efficiency measures installed through programs offered in 2014 produced annual electricity savings equal to roughly 0.69% of total U.S. retail electricity sales (Gilleo et al. 2015)—roughly eight times as large as the effect of DPV systems installed in that year (0.08% of retail sales).[5] Energy efficiency savings are projected to accelerate over the coming decade because of aggressive state energy efficiency resource standards and other policies that will be ramping up over the next decade (Barbose et al. 2013).

Many states and utilities have analyzed the rate impacts, cost-shifting, or cross-subsidies associated with DPV under current NEM rules and retail rates. These analyses come in several basic varieties. The most common compare the costs and benefits of DPV on a prospective basis, typically from the perspective of either the utility or society. Although not exclusively conducted for this purpose, DPV cost-benefit studies can be used to assess cost-shifting or cross-subsidies associated with NEM. Most formally, this is done through a Ratepayer Impact Measure (RIM) test, a standard technique used for decades to assess ratepayer impacts of energy efficiency and

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[4] The estimated impact of energy efficiency programs is based on data for incremental energy efficiency program savings over the period 1993–2014, as published in the American Council for an Energy Efficient Economy's (ACEEE's) annual state scorecard reports (for example, Gilleo et al. 2015). We assume that savings decay at a rate of 6.8% per year, based on the average measure-lifetime of 10.2 years for U.S. energy efficiency program portfolios (EPA 2015; Hoffman et al. 2015). Where gaps exist in incremental annual savings data, we estimate savings from ACEEE data on total U.S. annual energy efficiency program budgets.

[5] These estimates consider only the effects of utility ratepayer-funded energy efficiency programs. Accounting for naturally occurring growth in energy efficiency, as well as savings from other energy efficiency policies such as federal appliance standards and state and local building codes, would add to those impacts.

other demand-side management programs (CPUC 2001). This test involves comparing the net utility benefit to the lost revenues from the demand-side measure (in this case, DPV compensated through NEM). More common than a formal RIM test, DPV cost-benefit studies have been used to assess cost-shifting from NEM simply by comparing the estimated net benefits per kilowatt-hour of DPV generation to average retail electricity rates. In this case, average retail rates serve as a proxy for the revenue loss per kilowatt-hour of DPV generation (or exports), a rough equivalence in the case of primarily volumetric rates with minimal tiering.

The results of individual DPV cost-benefit analyses have varied widely, as documented by Hallock and Sargent (2015) and Hansen et al. (2013). In particular, among about a dozen studies conducted in recent years, estimates of the net benefits of DPV ranged from roughly 3.5 to 34 cents/kWh; as a result, the derived estimates of any cost-shift from NEM also vary widely, including many cases where the net benefits exceed the revenue loss. As documented methodically in Hansen et al. (2013), that variation in results reflects differences in the scope of benefits considered (which depend greatly on whether the study focus is on the utility system in particular or society), in the methods and assumptions used to evaluate particular benefits, and in the particular market and regulatory conditions of individual utilities and states. A great deal of attention has consequently been given to identifying best practices and guidelines for conducting DPV cost-benefit analysis (APPA 2014; Bradford and Hoskins 2013; Cliburn and Bourg 2013; Denholm et al. 2014; Fine et al. 2014; Keyes and Rábago 2013; Stanton and Phelan 2013).

Embedded cost-of-service (COS) studies are an entirely different approach that has been used to estimate the portion of a utility's costs for which NEM customers are nominally responsible. COS studies are fundamentally different from a cost-benefit analysis: rather than evaluating cost impacts on a prospective basis, these studies instead focus on allocating existing embedded costs (i.e., the rate base) and operating costs to each class or group of customers. Those class-average costs can then be compared to the revenues received under current rate designs and NEM rules, and any discrepancy between the two might be considered a "cross-subsidy." To date, COS studies of DPV customers have been performed by or for a number states and utilities, including the following:

- **California investor-owned utilities (IOUs):** A 2013 study commissioned by the California Public Utilities Commission (CPUC; E3 2013) included a COS analysis for NEM customers of the state's three large IOUs: Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). The study found, under a central scenario, that residential NEM customers contributed, on average, between 54% (SDG&E) and 84% (PG&E) of their allocated cost share, while commercial NEM customers contributed between 105% (SCE) and 122% (SDG&E) of their respective cost shares. In other words, commercial NEM customers were paying more than their cost of service.

- **Arizona Public Service (APS):** Based on a COS study summary submitted in advance of formally filing the full study, residential APS NEM customers under the current volumetric rates contribute, on average, 36% of their allocated share of costs (APS 2015). This compares to 87% for the residential customer class as a whole. Under the utility's residential demand-charge rate, NEM customers would contribute 72% of their allocated cost share.

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- **Louisiana utilities:** A COS analysis performed on behalf of the Louisiana Public Service Commission (Dismukes 2015) concluded that current residential NEM customers of the state's four IOUs pay an average of 70% of their cost of service, with a range of 52%–106% across the four IOUs. The same group of customers, without NEM, would have paid 158% of their cost of service, on average, or 142%–191% across the four IOUs. The study found similar results for the state's cooperatives, with current NEM customers contributing roughly 61% of their allocated cost of service versus the 150% they would have contributed in the absence of DPV with NEM.

A number of considerations are essential to the interpretation of COS studies for DPV customers (Cliburn and Bourg 2013). The first is that cross-subsidies—in the sense of paying more or less than one's allocated share of embedded costs—are pervasive, and in some cases intentional, within traditional rate design and ratemaking (Pentland 2014). Such cross-subsidies exist both across and within rate classes. For example, the recent APS COS study found that, under current rate structures, the various non-NEM rate classes contributed anywhere from 65% to 138% of their allocated costs. Within individual rate classes, cross-subsidies occur when rate designs do not mirror cost causation. For example, under rate designs where fixed costs are recovered primarily through flat volumetric rates, customers with below-average consumption—whether because of NEM, energy efficiency, conservation, few or intermittent occupants, or other reasons—may be cross-subsidized by other, higher-use customers.[6] Inclining block rates, such as those that have historically been used in California, exacerbate this effect. Similar intra-class cross-subsidies may exist between customers with highly variable load profiles and those with flatter load profiles. Any cross-subsidies associated with NEM are fundamentally the result of broader misalignment between common retail rate designs and cost causation (E3 2013).

A second and related consideration is that cost-shifting and cross-subsidies are not the same thing (Wellinghoff and Tong 2015).[7] For example, the COS study for California found that commercial NEM customers paid more than their allocated share of embedded costs. Thus, although NEM resulted in a cost-shift from those customers to non-NEM customers, that cost-shift actually served to *reduce* what, in the absence of NEM, would have been an even larger cross-subsidy (i.e., those customers would have paid even more than 105% to 122% of their allocated costs, as occurred with net-metered DPV). In a related vein, the Louisiana study showed that the state's residential NEM customers, because they are relatively high-use customers (as many NEM customers tend to be), would have paid well above their allocated cost of service in the absence of net-metered DPV. Thus, NEM essentially served to reverse and reduce in absolute magnitude the overall level of cross-subsidy (from a 158% overpayment to a 70% underpayment, in the case of the IOUs).

The preceding discussion pertains primarily to the impacts of DPV and NEM on non-solar customers. Comparatively little analysis has been done to evaluate the size of possible financial impacts to utility shareholders in terms of effects on shareholder returns or earnings. Oliva and

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[6] Many "fixed" costs, in fact, scale with peak demand over the long run, and they are thus often allocated among customer classes on that basis. To the extent that energy consumption correlates with peak demand, high-use customers may or may not be subsidizing low-use customers.

[7] Although somewhat beyond the scope of the present discussion, electricity prices are most economically efficient if based on marginal costs, including externalities. Thus, reliance on embedded COS studies to inform electricity rate design and pricing (whether for DPV customers or more generally) can lead to inefficient resource investments.

MacGill (2012) modeled the effects of residential PV on the operating profits of retail electricity suppliers and distribution network service providers in the Australian state of New South Wales. Focusing on a representative residential PV system, they estimate that, if exported PV is compensated at 6¢(Australian)/kWh (as currently offered by the dominant supplier), retail supplier annual operating profit would decline by $8(Australian)/kW (or 2% relative to a non-PV customer). At a PV export price of 60 ¢/kWh, they estimate almost a 200 $/kW reduction in retail supplier profits. For the distribution network service provider, they estimate that residential PV systems reduce annual operating profits by roughly 100 $/kW. A follow-up study (Oliva and MacGill 2014) found that the revenues and profits of retail suppliers and distribution network providers decline further when DPV customers shift their load to minimize grid exports and maximize self-consumption, under cases where exported PV generation is compensated at wholesale electricity market prices.

Another study by Satchwell et al. (2014) considered two prototypical U.S. utilities, a vertically integrated utility in the Southwest and a restructured distribution-only utility in the Northeast, and modeled the impacts of NEM on utility shareholder returns and earnings over a 20-year period. Under NEM penetration reaching 10% of total utility retail sales, they estimate that shareholder ROE and earnings were reduced by 3% and 8%, respectively, for the Southwest utility and by 18% and 15%, respectively, for the Northeast utility (Figure 2). They also estimated these utility shareholder impacts under a range of alternate scenarios related to the utilities' operating and regulatory environments and the value of solar. Across those scenarios, the estimated reduction in shareholder earnings ranges from 5%–13% for the Southwest utility and from 6%–41% for the Northeast utility, with similar ranges in the impacts on achieved ROE. The findings from Satchwell et al. (2014) highlight the high degree of variability in how NEM might impact utility shareholders as well as the dependence on the specific circumstances of any individual utility (e.g., underlying load growth, the degree to which DPV defers capital expenditures on other infrastructure, and details of the ratemaking process). These findings also illustrate that the financial impacts of NEM on utility shareholders may be much larger than the impacts on utility ratepayers, as indicated by the comparatively lower percentage changes to average utility rates shown in Figure 2.
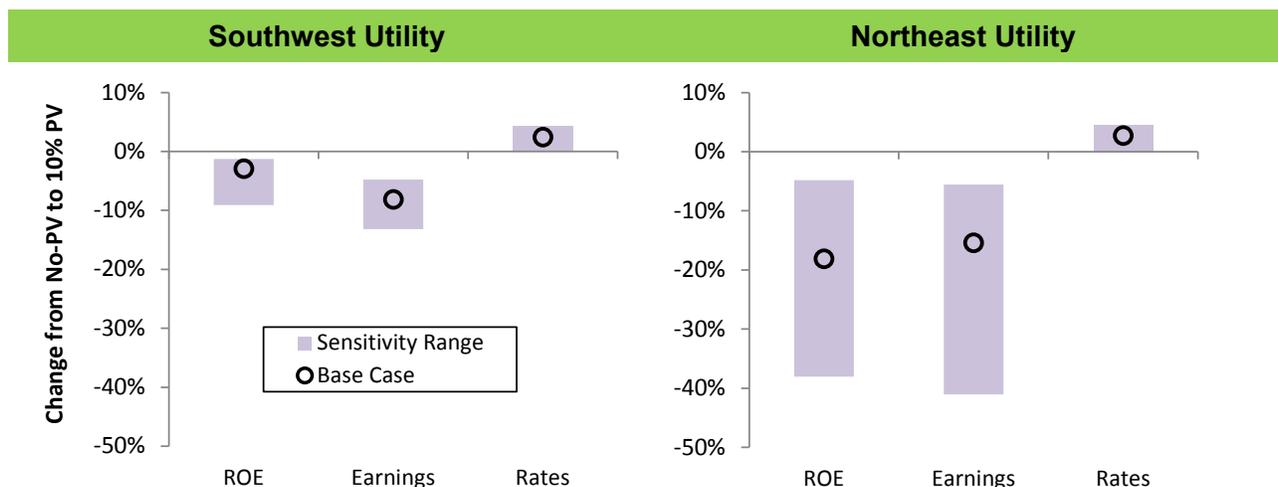
Figure 2. Modeled utility financial impacts of NEM for two prototypical utilities

Source: Satchwell et al. 2014

2.3 Reforms Specific to DPV Customers

Here we summarize trends in recent regulatory reforms targeting DPV customers specifically, with a focus on changes to NEM tariffs and the retail electricity rate structures under which DPV customers are served. We also briefly discuss reforms related to several other key terms of service—namely, interconnection rules and treatment of third-party ownership (see Text Box 2)—but other regulatory topics pertaining to DPV are not addressed, such as DPV incentive programs and the treatment of DPV within state renewable portfolio standards (RPSs). Section 2.4 addresses broader trends in retail rate design that are relevant to, but not specific to, DPV customers. A brief discussion of responses to concerns about the financial impact of DPV on incumbent utilities in Germany is provided in Text Box 3.

With respect specifically to reforms of NEM tariffs, the long-term historical trend has generally been supportive of DPV. The number of states where investor-owned, if not all, utilities are required to offer NEM rose from seven in 1990, to 22 in 2000, to 44 today (Stanton and Phelan 2013). Key provisions within NEM tariffs have also become progressively more favorable for DPV, as evident by the rising "grades" for state NEM rules issued in the annual *Freeing the Grid* report series (see, for example, Auck et al. 2014). These grades, which range from A to F, consider a variety of NEM design features, including program caps, eligible technologies and system sizes, rules for rollover of excess credits between billing periods, and many others. As shown in Figure 3, the national grade point average—i.e., the simple average of all state grades—has risen appreciably over time, from just 1.9 in 2007 to 3.0 in 2014, with much of that improvement occurring over the years leading up to 2010. In total, the number of states receiving a grade of A (i.e., 4.0) rose from five in 2007 to 18 in 2014. Similarly, state grades for interconnection rules have generally risen over time.
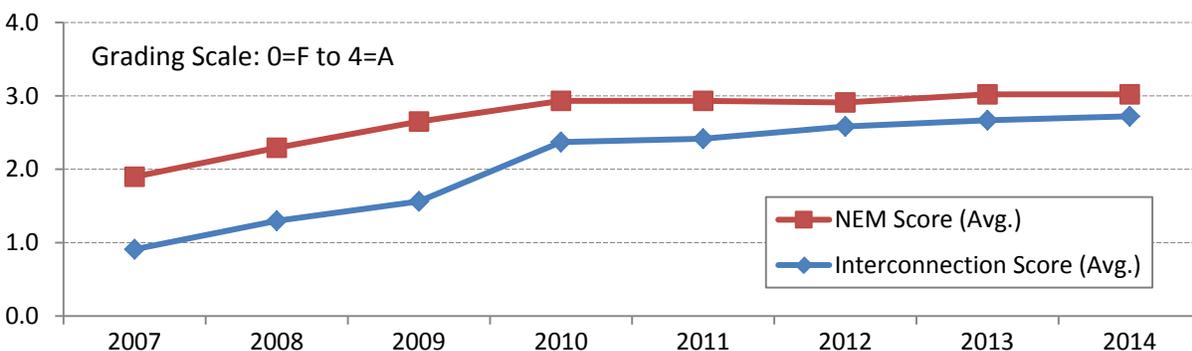
Figure 3. Average state NEM and interconnection grades from *Freeing the Grid*

Data source: Auck et al. 2014

However, future regulatory reforms targeting DPV customers are likely to be decidedly more mixed. Although incremental revisions to NEM rules continue to occur—for example, related to eligible system size, virtual NEM, and meter aggregation—many current proposals and discussions center around more-fundamental reforms, often expressly intended to address concerns about utility revenue erosion and cost-shifting. Virtually every state has seen at least one piece of legislation or regulatory action on NEM proposed in the past year or two, many of which are summarized in the quarterly *50 States of Solar* report series (e.g., Inskeep et al. 2015b)

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and by Stanton (2015). These and other potential reforms have also been widely discussed within an ever-expanding literature (Bird et al. 2013; Borlick and Wood 2014; Brown and Bunyan 2014; Brown and Lund 2013; Costello 2015; Faruqui and Hledik 2015; Glick et al. 2014; Kennerly et al. 2014; Kihm and Kramer 2014; Lazar 2015; Linvill et al. 2013; Tong and Wellinghoff 2015a; Wiedman and Beach 2013; Wood and Borlick 2013).

Drawing on both active proposals and the broader literature, we summarize below the range of reforms under consideration—focusing here on reforms specifically targeting NEM or other DPV customers and in the next subsection on reforms that would apply more generally (e.g., to all residential customers), though some overlap exists between the two. To be clear, our intent is simply to identify the kinds of reforms under consideration and, where not entirely obvious, to describe the nature of their implications for DPV markets. We do not seek to evaluate or compare the merits of these various possible reforms comprehensively, though much of the literature cited above and in the following discussion assesses or advocates particular approaches.

New or increased charges for DPV customers. Utilities in many states have proposed, been authorized to propose, or implemented new or increased charges specific to NEM customers (or for DPV or distributed-generation customers more generally). Such charges come in several forms. The most common to date have been standby charges based on the size of the PV system or increases to monthly per-customer charges for NEM customers (as opposed to broader increases in customer charges, as discussed in Section 2.4). Over the first three quarters of 2015, five utilities proposed new standby charges for NEM customers, ranging from $3 to $6 per kW of installed DPV capacity (e.g., $21 to $42 per month, for a 7-kW system), and eight utilities proposed new or increased monthly customer charges for NEM customers, ranging from roughly $5 to $50 per month (Inskeep et al. 2015a; Inskeep et al. 2015b; Inskeep and Wright 2015). Several other kinds of NEM-customer-specific charges have also been proposed or posited. For example, the proposed decision issued in CPUC's "NEM 2.0" docket adopts a one-time connection fee for new NEM customers, ranging from $75 to $100 (CPUC 2015d). Another concept is to charge NEM customers for PV generation or exports to the grid, such as with bi-directional distribution charges, where volumetric distribution service charges are assessed on exported generation (Linvill et al. 2013). Finally, at least one utility (Public Service Company of New Mexico) has proposed charging NEM customers higher volumetric rates for net consumption (Inskeep et al. 2015b).

Minimum bills. Minimum bills have been proposed as an alternative to increased fixed monthly customer charges, partly on the basis that they better preserve customers' ability to manage their utility bills, whether through DPV, energy efficiency, or otherwise (Kennerly et al. 2014). The Hawaii public utility commission (PUC) recently adopted minimum monthly bills for DPV customers ($25/month for residential and $50/month for commercial) as part of its broader reforms of NEM rules (HI PUC 2015).[8] In Massachusetts, a minimum bill for DPV customers was proposed as part of a broader settlement package, but ultimately it was not adopted. California recently adopted minimum bills ($10/month) as part of a broader reform of residential rate structures (Inskeep et al. 2015b).

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[8] Hawaii's minimum bills are applicable specifically to customers taking service under the NEM "self-supply" option, where only incidental grid exports are allowed.

Demand charge rates for DPV customers. Going beyond revisions to individual billing elements, many utilities have considered developing new retail rate structures specific to (and mandatory for) NEM customers.[9] The most common is a three-part tariff combining demand charges—based on some measure of the customer's maximum demand—with fixed monthly customer charges and relatively low volumetric charges. At least 13 utilities have proposed demand charge rates for NEM customers within the past year (Inskeep et al. 2015a; Inskeep et al. 2015b; Inskeep and Wright 2015); of those, Salt River Project's (SRP's) proposal was adopted in late 2014. The level of demand charges within these proposals varies widely, ranging from $1.5/kW to as much as $34/kW, as does the structure of the charges—e.g., in terms of the interval over which demand is measured, the use of demand charges differentiated by season or time of use (TOU), and tiering of demand charges. As with the two reforms discussed above (fixed monthly customer charges and minimum bills), demand charge rates have also been proposed for residential customers more broadly, though much of the recent focus has been specifically on NEM customers.

Reduced compensation for grid exports. A number of states have considered reducing compensation for electricity exported to the grid while continuing to allow customers to offset use directly with generation consumed behind the meter. Utility proposals have typically suggested compensating exports at prices below volumetric retail rates, based on, for example, wholesale electricity prices, avoided-cost-based rates, or the unbundled generation portion of retail rates. The Hawaii PUC recently adopted avoided-cost-based compensation for grid exports, applicable to DPV customers that plan to export more than an "incidental" amount of electricity back to the grid (HI PUC 2015).[10] The California IOUs' recent proposals within the state's NEM 2.0 docket also recommended reduced compensation for exported generation, based on either avoided costs or the generation component of retail rates. The PUC's proposed decision does not adopt the utilities' specific proposals, though it does reduce compensation for grid exports by deducting a $0.02/kWh to $0.03/kWh non-bypassable charge for public purpose programs (CPUC 2015d). Beyond these specific proposals, any number of other approaches could be used to price exported generation, and some might conceivably result in prices greater than retail rates. For example, the price for exported DPV could be based on a more expansive estimate of the value of solar or set at a level intended to support certain deployment or other policy goals.

Two-way rates. Under two-way ("buy-all/sell-all") rates, PV generation is metered and compensated independently from the customer's use. That is, rather than offsetting consumption, customers are compensated at a specified price for all electricity produced by their PV systems, and they are billed for use in the same manner as would occur in the absence of the PV systems. Importantly, the price paid for PV generation may be higher or lower than retail electricity rates, and thus two-way rates can either exacerbate or alleviate utilities' fundamental concerns with NEM. A great many varieties of two-way rates have been implemented or considered, with differing approaches to establishing the price. One commonly considered approach is a Value of Solar (VoS) tariff, where the price for PV generation is based on an estimate of the value (i.e., net benefits) of that generation. As in DPV cost-benefit studies, any number of possible sources of value may be considered when establishing prices for a VoS tariff. In the most limited form,

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[9] COS studies and/or the creation of separate rate classes for NEM or DPV customers have sometimes also been suggested as a means to develop rates specific to these customers.

[10] However, Hawaii's avoided-cost rates are exceptionally high, ranging from roughly $0.15/kWh to $0.28/kWh.

some utilities have proposed payments based solely on wholesale market prices or avoided generation costs, though other benefits are also often included, such as those associated with deferred transmission and distribution (T&D) capacity, environmental impacts, improved reliability, risk reduction, or local economic development (Taylor et al. 2015). Another form of two-way rates is a FiT, where the price for PV generation is established through a competitive procurement process or through some administrative determination of the level necessary to support a desired level of deployment (Bird et al. 2013). As discussed further in Section 2.4, two-way rates for DPV might also occur though unbundled pricing of grid services, which entails reforms to pricing of both customer-sited generation and consumption (Glick et al. 2014).

Transfer of renewable energy certificate (REC) ownership through NEM. Many utilities have offered rebate or other incentive programs for DPV where ownership of RECs transfers to the utility as a condition of participation. One state (Vermont) has extended the same treatment to NEM as well, though customers have the option to retain REC ownership in exchange for reduced NEM compensation. Several Arizona IOUs similarly proposed that all DPV customers surrender RECs to the utility as a condition of interconnection, though those proposals were ultimately withdrawn (ASU-EPIC 2014). Transferring REC ownership does not directly address underlying utility revenue impacts of NEM, but rather it intends to offset those impacts by providing the utility with an additional source of compensating value: the ability to directly apply generation from NEM systems to its RPS. Without transfer of REC ownership to the utility, DPV still indirectly assists utilities in meeting RPS requirements by reducing their load and thus the basis upon which RPS procurement obligations are based. That benefit, however, is only a fraction of what would be achieved in the case where REC ownership is transferred entirely.

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Third-party ownership of DPV has been one of the major enablers for rapid market growth in recent years. In 2008, only five to six states were contemplating third-party owned (TPO) rooftop PV (Kollins et. al 2010); by 2014, 25 states (along with Washington, D.C., and Puerto Rico) allowed for some form of TPO. With this expanded access, TPO PV systems (under both leases and power-purchase agreements) constituted 72% of the U.S. residential solar market in 2014 (Litvak 2015).

Given the close correspondence between growth of TPO and of DPV markets more generally, one way that states or utilities have indirectly sought to limit the effects of DPV and NEM on utilities and non-solar customers is by restricting TPO. As shown in Figure 4, five states explicitly disallow third-party power-purchase agreements, and 20 have unclear rules and laws. Some states or utilities may allow TPO but restrict or disallow participation in incentive programs or in NEM. Restricting TPO, in effect, circumvents many of the issues that NEM and retail rate reforms targeting DPV customers intend to address. That said, the general trend has been toward easing restrictions on TPO, potentially creating new pressure for NEM and rate reforms. Since 2011, six states (Georgia, Iowa, New Hampshire, Texas, Rhode Island, and Vermont) have revised their rules to allow TPO, while three states (Kentucky, Oklahoma, and South Carolina) created new TPO restrictions (DSIRE 2011; DSIRE 2015).
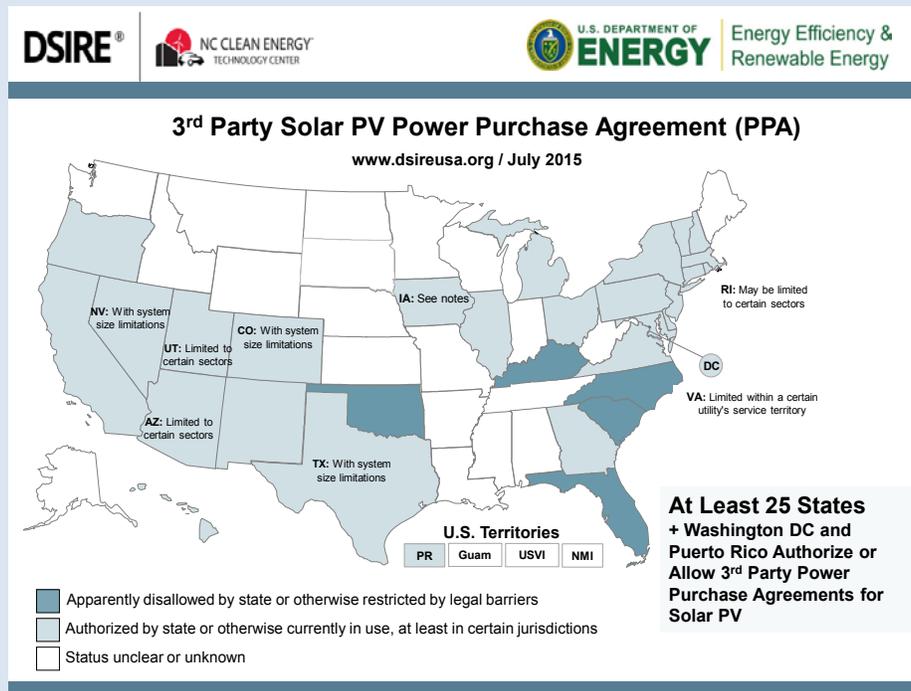
Figure 4. Restrictions on Third-Party Ownership of DPV
Data source: DSIRE 2015

Text Box 3. Efforts to Address the Financial Impacts of DPV Growth on Incumbent Utilities in Germany

The U.S. DPV market is unique in the degree of its reliance on NEM. Most other major DPV markets, particularly those in Europe, have relied instead on feed-in tariff (FiT) mechanisms, at least historically. In either case, concerns about rate impacts and cross-subsidies may arise. However, because FiT compensation does not directly reduce utility sales or revenues, utilities are not financially affected in the same way as with NEM, and thus concerns about erosion of utility profits are less prevalent and acute.[11] Nevertheless, many countries are confronting many of the same broader conditions driving reforms to utility regulatory and business models, and current initiatives underway abroad can help to benchmark and inform U.S. strategies.

Germany, in particular, has been an early leader in the adoption of DPV, but until recently this PV build-out has not imposed severe financial impacts on load-serving entities (LSEs) or distribution system operators (DSOs). These trends are beginning to change for several reasons. First, significant investments in distribution and transmission networks will be required, driven by DER integration, broader grid modernization efforts, and other factors (Buechner et al. 2014). Second, reduced FiT payments since 2012 have incentivized higher levels of self-consumption by DPV customers and therefore greater revenue erosion for LSEs and DSOs. Because DSO revenues are decoupled from throughput, revenue erosion from self-consumption primarily impacts non-solar customers but does not directly threaten DSO returns. Increasing rates of self-consumption are estimated to reduce revenues for recovery of grid costs by roughly 330 million euros annually through 2020 (Kelm et al. 2014).

Several reforms are currently under consideration in response to these changing conditions. Performance-based compensation for DSOs may be implemented to incentivize more-efficient investment decisions related to grid expansion and to better account for the heterogeneity of DPV expansion trends among DSOs (BMWi 2015; BNetzA 2015). In order to limit revenue erosion related to self-consumption, a limited set of surcharges can now be levied on forgone grid demand from owners with new PV systems larger than 10 kW. Further reform of the grid surcharge structure and fee allocation is intended over the coming years, though consensus has not yet emerged. Discussions have included a reduction of grid-fee exemptions for certain combined heat and power applications, a national burden-sharing of grid expansion expenses beyond the individual DSO, and a grid service fee that is proportional to the installed DPV capacity (demand charges are thought to be difficult to assess for residential customers in the absence of smart meters).

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[11] Even with a FiT, distribution utilities and other traditional electric system infrastructure providers may still experience an erosion of earnings opportunities, to the extent that those investments are displaced by DPV. In addition, regardless of how DPV compensation occurs, wholesale generators may be financially impacted through the suppression of wholesale market prices.

2.4 Broader Retail Rate Reforms

Beyond those reforms specific to DPV customers, broader retail electricity rate reforms have also been recently enacted or considered, and many of these may have significant implications for the DPV market. Motivations for these broader reforms are diverse, but they can be traced partly to flat or low load growth in many regions, for reasons that go beyond the impacts of just DPV. These trends are occurring at the same time that utilities are confronted with the demand for new infrastructure investments needed to maintain reliability, modernize the electricity grid, and meet clean energy goals (Stanton 2015). Interest in rate reform is thus born out of concerns about ensuring both that ratepayer-funded capital investments are being efficiently made and that utilities have the opportunity to recover the cost of these investments.

Among the set of broad rate reforms under consideration, two stand out as the most significant for the DPV market: increases in fixed monthly customer charges for residential customers and greater reliance on time-varying pricing. In addition, although not necessarily indicative of a broad national trend, efforts to reform tiered pricing structures in California have significant implications for the U.S. DPV market as a whole, given the state's historically dominant presence. Below, we briefly summarize these and other reforms that are currently under consideration or have been discussed more generally in the literature, some of which mirror those specific to DPV customers discussed in Section 2.3.

Increased monthly customer charges. Far and away, the most pervasive recent trend in retail rate reform has been the steady stream of proposals to increase monthly customer charges for residential customers (as distinct from those proposals seeking to increase customer charges only for DPV customers). At least 48 utility proposals to increase residential customer charges were issued or under review during the first three quarters of 2015—see Figure 5, which is based on data from Inskeep et al. (2015a; 2015b) and Inskeep and Wright (2015). Those proposals sought increases in customer charges ranging from $1/month to $39/month ($6/month on average). Among those cases where a commission decision was issued by September 2015, most either denied utilities' requests or approved increases lower than proposed amounts. From the perspective of DPV markets, across-the-board increases to customer charges for all residential customers are important chiefly because of the corresponding reductions in volumetric rates, as those are the source of bill savings through NEM.

Demand charges. Demand charges are common for commercial customers, but they have yet to achieve broad application in the residential sector; fewer than 20 utilities currently offer residential demand charge rates, and in almost all those cases the rates are voluntary (Hledik 2015). Interest in residential demand charges has begun to grow, however, in part due to the now-widespread deployment of advanced metering in many utility service territories.[12] If made mandatory for all residential customers, the implications for DPV customers would partially mirror those mentioned above with respect to increasing customer charges: namely, the corresponding reduction in volumetric charges would reduce the bill savings achieved through NEM. The important difference, however, is that DPV systems may yield some demand charge savings (depending on the customer's load profile and demand charge design), partially

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[12] Concerns continue to be expressed about whether or not residential customers can reasonably be expected to understand and respond to demand charges (Alexander 2015; Springe 2015).

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offsetting the reduced savings on volumetric charges. Load management and onsite storage can be used to reduce demand charges, independent of whether the customer also has DPV.
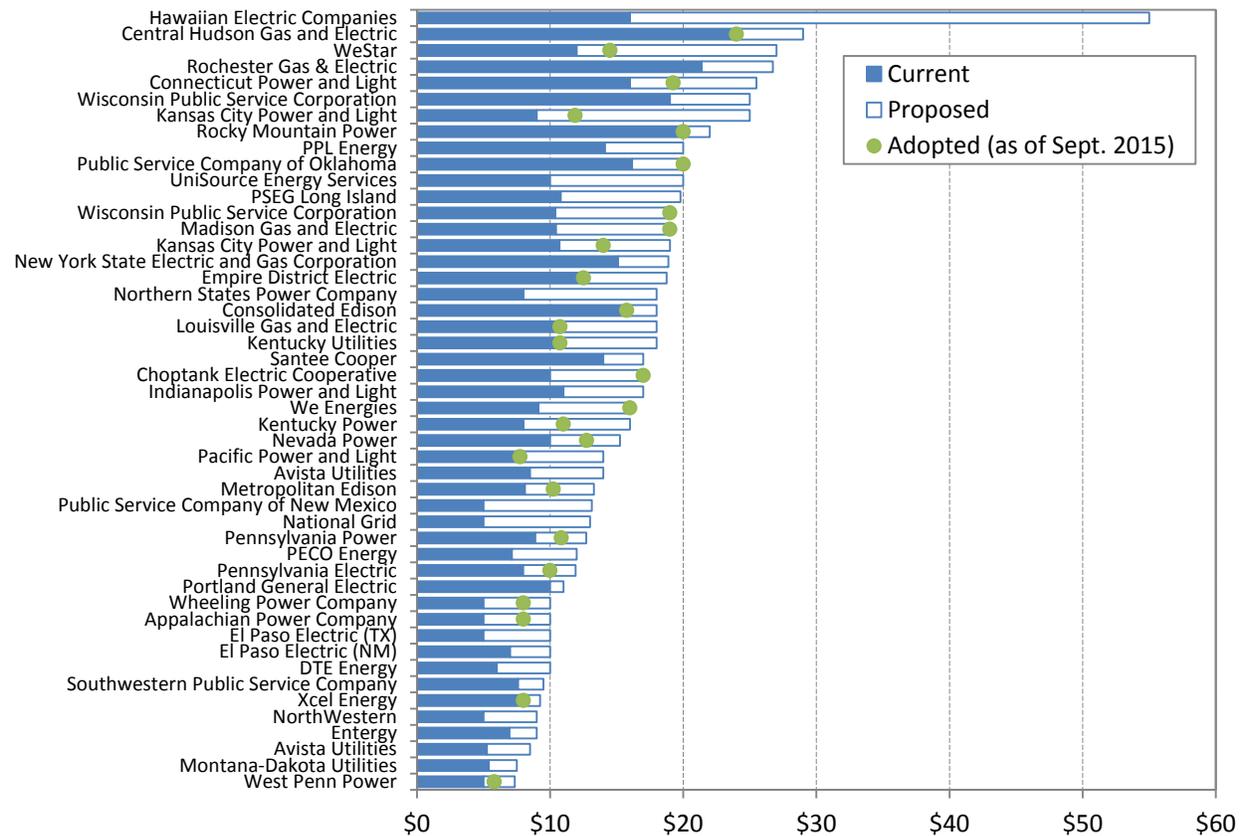
Figure 5. Proposals to increase monthly residential customer charges (first three quarters of 2015)

Data sources: Inskeep et al. 2015a, 2015b; Inskeep and Wright 2015

Unbundled attribute pricing. Glick et al. (2014) identify demand charges as one step along a larger continuum of unbundled attribute pricing, where customers pay for services received and, in the case of customers with self-generation, are paid for services provided to the grid under two-way rates. This could include unbundling of generation costs, capacity costs, T&D costs, and ancillary services as well as other (currently unpriced) attributes, such as those related to environmental impacts or resiliency.

To a limited degree, unbundled attribute pricing for consumption already exists in restructured retail markets where generation, transmission, and distribution services are individually priced and billed. On the generation side, some wholesale market operators have begun allowing distributed generation (DG) resources to sell certain grid services into ancillary services markets. Discussions about more expansive unbundled attribute pricing have occurred within the context of New York's Reforming the Energy Vision (REV) initiative and as part of Hawaii's NEM reforms; one California utility, SDG&E, has also engaged in collaborative discussions with other stakeholders around this broad concept (HI PUC 2014; NYPSC 2015b; Yunker and Fine 2014).

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From the perspective of DPV customer-economics, the value of unbundled attribute pricing depends on what particular attributes or services are unbundled and their pricing. To the extent that the same attributes are embedded in traditional retail rates, unbundled pricing may or may not provide greater value to a DPV customer than traditional NEM with flat volumetric rates. Over the long run, however, this kind of pricing structure could spur innovations in DPV system design and deployment strategies that preserve, or even improve upon, the customer-economics that exist under the current NEM paradigm.

Time-varying pricing. Economists have long recognized the value of time-varying retail electricity pricing in providing a more efficient price signal to consumers (Vickrey 1971; Schweppe et al. 1987) as well as potentially a more equitable approach to recovering utility infrastructure costs than fixed or demand charges (Lazar and Swe 2015). Interest has heightened in recent years as many have recognized the role time-varying pricing could play in providing system flexibility for integration of variable generation and for managing interactions between customer-sited resources and utility distribution systems (Cappers et al. 2011; Glick et al. 2014; Lazar 2014; Porter et al. 2012).

Despite this widespread recognition of potential benefits, adoption of time-varying pricing has historically been limited. While TOU pricing is common among commercial and industrial customers, more-granular and dynamic pricing (e.g., real-time hourly pricing or RTP) is much less widely available. Within the residential sector, time-varying rates are generally offered only on a voluntary, opt-in basis or as pilot programs, and uptake has correspondingly been low: less than 1% of U.S. households currently take service under time-varying rates (FERC 2014). That said, prospects for wider adoption continue to improve with the rapid expansion of advanced metering—from just over 5% of households with advanced meters in 2007 to more than 31% in 2014—and the emergence of new technologies and service models to assist customers in responding to price signals (FERC 2014).

Among the most significant steps toward broader application of time-varying pricing, PUCs in California and Massachusetts recently ordered regulated utilities to transition over a number of years to default TOU rates for all residential customers (CPUC 2015b; MA DPU 2014). Regulators in Hawaii and New York have also signaled their intent to move toward more-widespread use of time-varying rates, and roughly a dozen other utilities are testing and evaluating new dynamic pricing tariffs or moving forward with broader rollout (Cappers et al. 2015; FERC 2014; HI PUC 2014; NYPSC 2015a).

The implications of time-varying pricing for DPV markets are complicated and mixed. As discussed in greater depth later, DPV customers could benefit in the near term by, in effect, being able to sell exported PV generation to the utility at higher prices during peak pricing periods; however, that benefit may erode over the long term if solar penetration on the grid increases and causes peak pricing periods to shift to evening hours. That said, if time-varying rates were broadly implemented, price responsiveness by participating customers would mitigate some of the decline in value of solar generation (Mills and Wiser 2015). Additionally, insofar as time-varying pricing, rather than higher fixed charges or demand charges, is used to recover utility infrastructure costs, many customers may have greater ability to manage their utility bills. In particular, onsite storage and other demand-flexibility measures can be used by DPV and non-DPV customers to respond to time-varying pricing.

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Locational pricing. Analogous to time-varying pricing, locational pricing is differentiated based on the particular location of the customer. Although common in wholesale power markets, with pricing differentiated by the network node or zone on the bulk power system, it has not yet been extended into retail electricity rate structures. In theory, retail locational pricing might be differentiated even more granularly, based on the feeder or other location within the distribution network (Glick et al. 2014). The impact on DPV markets would thus largely be to direct new development toward those locations where it provides the greatest value and imposes the least cost. Recognizing that locational pricing of retail electricity service may not be politically or practically feasible, other concepts have also been advanced for incentivizing optimal siting of DERs on the distribution system. These include offering location-specific credits or payments to resources sited in preferred areas of the distribution network as well as location-specific interconnection fees and processes (Edge et al. 2014; Moskovitz 2001).

Tiered pricing in California. California hosts almost 50% of all residential PV systems installed in the United States since 2010. One key factor behind the state's prominence is the inclining block rates offered by the state's three large IOUs. Such rate structures are relatively common, but California's are unique in the wide differential between lower and upper usage tiers. For example, at their peak in 2009, PG&E's two upper usage tiers were both in the range of 40–50 cents/kWh, compared to 12–14 cents/kWh for usage in the two lower tiers (Wan 2014).

This situation was a vestige of the state's energy crisis in 2001, when the legislature froze rates for the lower usage tiers, forcing utilities to load all future growth in revenue requirements into the upper tiers. As a result, DPV became highly attractive for high-usage customers. However, concerns about distortions and inequity among customers caused by this rate structure—not just in relation to DPV, but more generally between low- and high-usage customers—created pressure to reduce the pricing differential across usage tiers.

Legislation passed in 2009 authorized the PUC and utilities to begin this process through small annual increases in rates for the lower usage tiers. Further legislation in 2013 prompted more significant reforms, and the PUC issued a landmark order in 2015 requiring the utilities to implement several significant changes to residential rate structures by 2019, with incremental steps over the intervening years (CPUC 2015b). Among those changes, the utilities were required to consolidate their residential rates to two usage tiers, with the pricing differential between the tiers narrowing to 25%. The implications of these reforms for the DPV market are mixed: although lower prices for upper tiers will certainly erode the economics of DPV for high-usage customers, the corresponding price increases for lower tiers will improve the economics for low-usage customers.

3 Potential Impacts of Net Metering and Rate Reforms on DPV Markets

The preceding section described reforms to NEM and retail electricity rate design currently under consideration, many of which could pose significant challenges to the U.S. DPV market and to fulfillment of the SunShot goals. In this section, we evaluate how such reforms could impact the customer-economics and deployment of DPV over the near and long terms. Naturally, policymakers and other decision makers must balance those impacts on solar customers and the solar sector against other competing policy objectives when evaluating potential NEM and retail rate design reforms. Our intent is, therefore, simply to inform such deliberations by illustrating one aspect of the larger set of tradeoffs.

We focus first on one specific NEM reform increasingly being considered: changes to the compensation for DPV generation exported to the grid. As states reach NEM program caps or are otherwise considering whether to continue NEM, many may move to such a structure, and thus we consider it to be effectively the default counterfactual to NEM as it exists today.[13] We show how compensation for exported generation at wholesale prices, in particular, would impact both the customer-economics and deployment of DPV, based on a series of new analyses described below. We then show how other kinds of NEM and retail rate reforms—such as the application of increased fixed charges, demand charges, minimum bills, and TOU rates—could impact customer-economics and deployment, drawing primarily on recent existing studies. Where applicable, we discuss the potential implications of other dynamics occurring in parallel in the industry, such as the emergence of customer-sited storage and demand response.

3.1 Replacing NEM with Wholesale Prices for Exported Generation

The essential feature of NEM is that it allows generation exported to the grid to be credited, one-for-one, against later consumption or charges. A reduction in the credit received for exported generation thus represents a fundamental departure from, and effectively an elimination of, NEM. In the analyses that follow, we consider the specific case where, in the absence of NEM, excess generation exported to the grid in each hour is compensated at wholesale electricity prices. Other variants on this approach are possible; in particular, exported generation could be measured and compensated at intervals other than hourly and/or at prices lower or higher than wholesale electricity prices. As discussed in Section 2.3, two-way rates are an entirely different alternative to NEM. And of course, NEM could be retained in its essential form but combined with additional charges imposed on DPV customers. The analyses presented here should therefore be considered illustrative and not as a comprehensive comparison of traditional NEM to all possible alternatives; analyses of some of those other alternatives, however, are presented in Section 3.2.

3.1.1 Impacts on DPV Customer-Economics

A handful of prior studies have assessed the impact of NEM on the customer-economics of DPV, compared to alternative levels of compensation for exported generation. In general, these studies support the view that NEM can provide significant value to DPV customers, but they are all

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[13] Indeed, this is the direction Hawaii is currently heading, and utilities in California and Arizona have recently issued similar proposals.

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limited in scope, focusing mostly on residential customers and often on individual states—in many cases, California, which is especially unique given its steeply tiered rate structures:

- Cook and Cross (1999) estimated the utility bill savings that NEM provides to a representative residential customer with PV in Maryland, compared to a counterfactual in which PV generation exported to the grid is compensated at the utility's avoided-cost-based rate. Based on their analysis, NEM provides roughly 56% greater bill savings than the alternative considered.

- Darghouth et al. (2010) compared bill savings with NEM to an alternative where hourly exported PV generation was compensated at an avoided-cost rate, relying on hourly load data for a sample of roughly 200 residential customers in California. For systems sized to meet 75% of customers' annual energy requirements, roughly 45% of PV generation was exported to the grid, and the bill savings under the hourly export approach were roughly 11%–12% lower than under NEM (though somewhat higher for high-use customers).

- Darghouth et al. (2013) compared bill savings with NEM to an alternative where hourly exported PV generation was compensated at an avoided-cost rate, in concert with other variations in underlying retail rate structures (flat rates, TOU, and RTP) and market conditions (gas prices, carbon prices, and renewable penetration levels). Based on a sample of residential customers in California, they estimated that bill savings are 23% to 47% higher with NEM than when hourly exported generation is compensated at avoided-cost-based rates, depending on the electricity market scenario and rate option.

- Wiser et al. (2007) focused on commercial customers in California, comparing annual bill savings with and without NEM for 24 actual commercial PV installations in the state. Under the without-NEM cases, they assume that grid exports within each 15-minute interval are compensated at a stipulated price. They found that eliminating NEM would, in the vast majority of cases, result in less than a 10% reduction in bill savings provided that the price paid for grid exports was at least $0.09/kWh or the system was sized below 25% of annual building load. For lower grid export prices or larger systems, however, elimination of NEM could reduce bill savings by a significantly greater amount, depending in part on the particular customer load profile.

- Kann (2015c) compared the cost-effectiveness of residential DPV under current NEM rules and under an alternative where exported generation is compensated at 50% of average retail rates. Based on this analysis, residential customers in 20 states can currently achieve "grid parity"—that is, generate positive returns in year 1—under current NEM rules. If exported generation were compensated at 50% of retail rates, however, no states would currently achieve grid parity.

To demonstrate more broadly the impact of NEM, we present a series of analyses below comparing the customer-economics of DPV with and without NEM.[14] We compare customer-economics in terms of payback period, estimated using NREL's System Advisor Model (SAM), a pro-forma financial model used widely for evaluating renewable energy projects. The analyses cover both residential and commercial customers and span a range of underlying rate structures,

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[14] Although this comparison is focused on customer-economics, it is also important to note that the relative simplicity of NEM (at least at a conceptual level) is arguably also an important element in its value proposition, and may therefore also be relevant when considering alternatives to NEM.

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geographies, and other relevant conditions. In all cases, we assume that installed costs are equal to the 2020 SunShot targets ($1.50/W for residential PV and $1.25/W for commercial PV, in real 2010 dollars) and that no incentives are provided, consistent with the long-term vision of SunShot Initiative.[15] Under cases without NEM, excess generation exported to the grid in each hour is compensated at state-specific wholesale electricity prices developed through a parallel modeling effort.[16]

Before presenting results of the analysis, we first illustrate the fundamentals of how customer payback period would be eroded by replacing NEM with wholesale compensation for exported generation. Under this kind of compensation regime, the change in customer payback relative to traditional NEM is directly a function of two factors: (1) the quantity of PV generation exported and (2) the price paid for exported PV, relative to the retail price that would otherwise apply under NEM. Because payback period is proportional to the *inverse* of annual bill savings, the impacts of these two variables on customer payback are non-linear and interactive, as shown via a simplified model illustrated in Figure 6.[17] Thus, if either the quantity of exported generation is relatively high or the price for exported generation is relatively low compared to retail prices, then payback is more sensitive to the other variable.
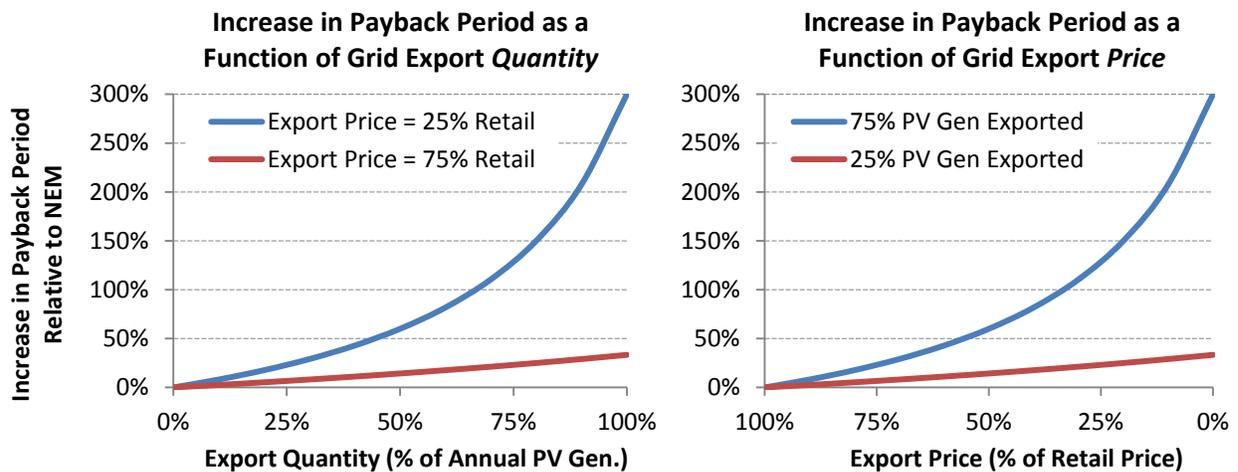
Figure 6. Impact of grid export quantity and price on payback period (simplified model)

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[15] Specifically, we assume no state incentives and that the federal investment tax credit (ITC) is limited to 10% for commercial entities and is unavailable for residential owners—as will be the case after the most recent ITC extension expires. To be clear, the purpose of this analysis is not to characterize the customer economics of DPV for any particular year, but rather, to do so under the set of long-term conditions envisioned by the SunShot Initiative.

[16] Wholesale prices were derived using NREL's Regional Energy Deployment System (ReEDS) capacity-expansion model under a SunShot scenario assuming achievement of the SunShot 2020 cost targets and associated solar deployment levels. All other assumptions are based on the ReEDS Standard Scenario Reference Case (Sullivan et al. 2015). For the sake of internal consistency, we escalate retail electricity prices at the same rate as implied by the wholesale price projections for each state. If retail prices were to rise faster (or slower) than wholesale prices, then the differential in payback between cases with and without NEM would be larger (or smaller).

[17] Figure 6 is based on a simplified functional relationship that ignores complexities associated with tiered rate structures and compensation for NEM credits at year-end, which are captured within the SAM analysis.

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3.1.1.1 Residential Customers

Focusing first on the residential sector, we examine the change in customer payback period for a 5-kW system installed by a residential customer within a representative utility service territory in each of six states: Arizona (APS), Connecticut (Eversource Energy), Georgia (Georgia Power), Minnesota (Northern States Power Company), New Jersey (Jersey Central Power & Light), and Oregon (Portland General Electric).[18] For each utility, we calculate and compare the simple payback period of the PV system with and without NEM. In both scenarios, we assume that usage is billed under the current, standard residential electricity tariff for each utility, which consists primarily of volumetric charges.[19] The only difference between the with- and without-NEM scenarios is in the treatment of PV generation exported in each hour: whether it is netted against usage at a different time, in the case of NEM, or is compensated at the state-specific wholesale electricity price, in the case without NEM.

As shown in the left-hand panel in Figure 7, elimination of NEM would increase simple payback periods for a standard 5-kW residential system by 2.4–8.2 years (or 20%–69%) across the six representative states evaluated. As previously noted, increases in payback periods are driven by the quantity of exported generation and the differential between wholesale and retail prices as shown in the right-hand panel in the figure. Thus, for example, the increase in payback period is relatively large for the Oregon and Connecticut systems, where PV exports for a 5-kW system are relatively high and projected wholesale prices are significantly below average residential retail rates. Conversely, the impact on payback period is smallest for the system in Georgia, where grid exports for a 5-kW system are comparatively low and the differential between retail and wholesale prices is narrow.
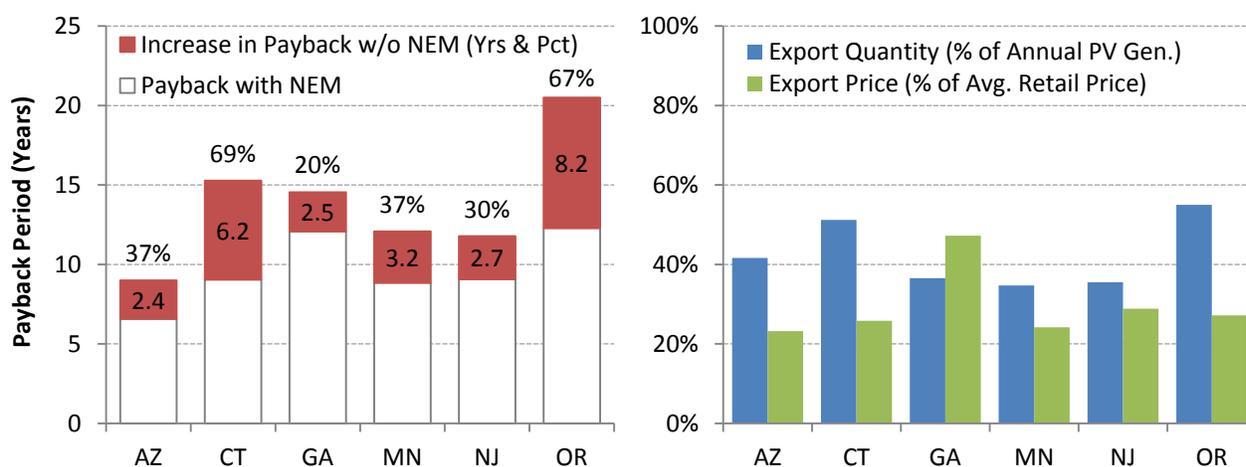
Figure 7. Impact of NEM elimination on residential PV payback period (5-kW system)

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[18] A 5-kW system represents the following percentages of annual load for each representative residential customer: 66% (AZ), 68% (CT), 55% (GA), 50% (MN), 51% (NJ), and 73% (OR).

[19] We assume the following set of residential tariffs: APS (E-12), Eversource Energy (Rate 1), Georgia Power (R-20), Northern States Power Company (Rate Code A01), Jersey Central Power and Light (Service Classification RS), Portland General Electric (Schedule 7). These rates have fixed monthly customer charges ranging from roughly $2 to $19 per month. The volumetric charges under these rates generally have some seasonal differentiation and/or usage tiers with inclining block structure.

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These cross-state comparisons are based on a single generic system design, and they rely on particular assumptions about future wholesale electricity prices and retail electricity rates. Thus, they do not capture the full range of state-specific factors that could alter the relative magnitude of effects. Rather, the results shown here simply illustrate the general magnitude of impacts that might occur with elimination of NEM, and they highlight how certain state- or utility-specific conditions could influence the degree of impact.

Because the quantity of grid exports is such a key driver for the loss of customer value with elimination of NEM, such policy reforms might spur customers to deploy DPV systems in ways that minimize grid exports. One ready response would be simply to install smaller systems. To illustrate, Figure 8 shows the difference in payback period with and without NEM for the same set of states and utilities but with PV systems sized to meet 50%, 75%, and 100% of each customer's annual consumption.[20] As expected, smaller system sizes result in reduced impacts to payback period, commensurate with the lower levels of grid exports. For example, in the case of the Arizona system, just 31% of PV generation is exported when the system is sized to meet 50% of the customer's annual load, compared to 57% of PV generation exported for a system meeting 100% of annual load. The impact of a loss of NEM on payback correspondingly shrinks from a 3.7-year to a 1.4-year increase. The more favorable payback periods likely would drive customers to install smaller systems if NEM were eliminated.
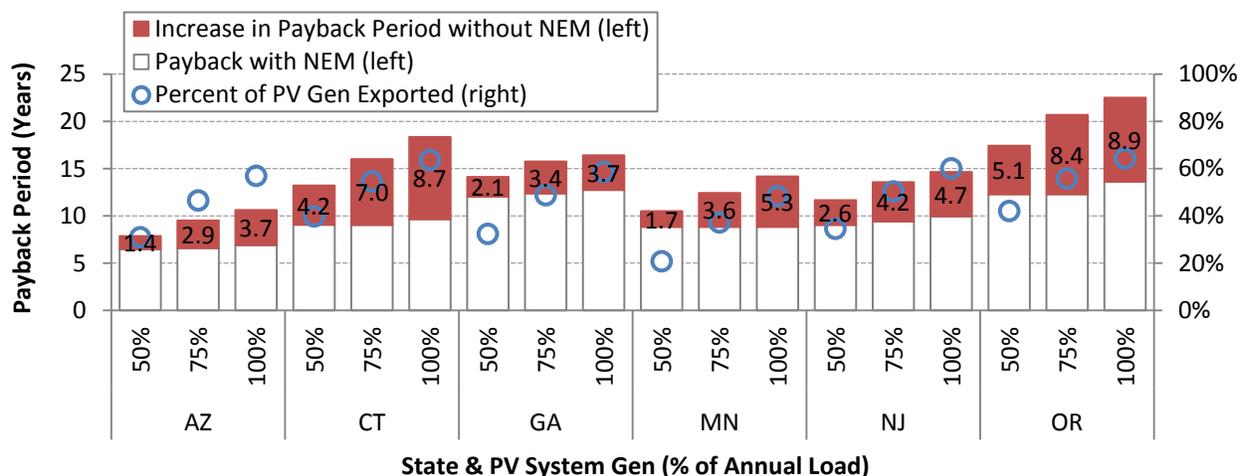
Figure 8. Impact of NEM elimination on residential PV payback period (varying PV system sizes)

A variety of other options beyond downsizing systems could also be pursued to minimize grid exports in the absence of NEM. These include, for example, orienting systems to match PV production to load more closely (Fischer and Harack 2014) and/or shifting energy consumption to times when PV production occurs. With respect to the latter, a recent analysis by Rocky Mountain Institute (Dyson et al. 2015) examined the potential for demand flexibility (so-called "flexiwatts") to reduce grid exports of residential DPV. In one case, the researchers considered a customer of Alabama Power Company and the economics of demand flexibility under current

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[20] For the system-size sensitivity cases, installed costs were adjusted slightly from the SunShot cost-reduction targets to reflect economies of scale gained or lost with changes in system size, based on data from Barbose and Darghouth (2015). Despite these adjustments, payback periods with NEM rise with increasing PV system sizes for some states because of inclining usage tiers, which result in declining marginal bill savings with increasing system size.

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tariffs, which compensate exported PV generation at avoided-cost-based rates. Based on just three end uses—electric vehicle (EV) charging, air-conditioning, and electric water heating—they estimated that demand flexibility could cost-effectively reduce PV exports from 36% of annual generation to just 7%. Recognizing the potential for demand flexibility to aid in the integration of DPV, several utilities—including Hawaiian Electric Company (HECO), SCE, and APS—have initiated pilot programs involving DPV customers equipped with advanced load controls and dynamic pricing.

Another emerging and high-profile solution would be to combine DPV and customer-sited storage: charging the storage unit during times when solar generation exceeds load and discharging it later, in effect arbitraging between wholesale and retail electricity prices. Several recent studies have shown that, in some markets, storage may already be, or will soon be, a cost-effective option for reducing grid exports. In one such analysis, Kann (2015b) considered a residential customer in southern California under a scenario where grid exports are compensated at roughly $0.10/kWh less than retail electricity prices. At current costs and with currently available incentives, the addition of storage would raise the internal rate of return on the investment from 9% to 11%. Another report by Rocky Mountain Institute (Bronski et al. 2015) also assessed the economics of solar plus storage, though focusing on cases where no compensation is provided for grid exports. Under this scenario, the researchers found that, within three of the five case study cities examined, the combination of solar and storage would become cost effective for residential customers within roughly the next decade. For one of these three cities, Honolulu, storage already provides a cost-effective means to reduce grid exports that would otherwise be uncompensated (Dyson et al. 2015).

Collectively, the results shown here suggest that the loss of NEM would degrade the customer-economics of DPV, though the degree of impact depends on the size of the gap between retail prices and the price paid for grid exports as well as on the ability of customers to minimize grid exports through some combination of system sizing and orientation, load shifting, and customer-sited storage. To the extent that customers can manage their grid exports, the elimination of NEM ultimately may not avert load defection from the utility's system or address utility concerns about revenue erosion.

3.1.1.2 Commercial Customers

Turning to the analysis of commercial customers, we again compare simple payback periods with and without NEM.[21] As in the residential analysis, we assume achievement of the SunShot cost targets and that, in scenarios without NEM, exported PV generation in each hour is compensated at projected wholesale prices. The analysis for commercial customers, however, is more complicated than for residential customers, given widely varying commercial customer load shapes and retail rate structures.

We can anticipate that, in some cases, the loss of NEM (as modeled here) will have minimal impact on the customer-economics of commercial PV. This could occur for either of two reasons. First, for many commercial customers, roof area is a binding constraint on PV system size, limiting solar generation to a fraction of annual building load and consequently minimizing

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[21] Commercial PV projects are often evaluated in terms of other financial metrics, such as the internal rate of return; however, we focus on payback period for simplicity and consistency with the prior section on residential PV.

PV generation exports to the grid. Second, even if substantial grid exports occur, many commercial rate structures have large demand charges and correspondingly low volumetric energy rates. In this case, little difference may exist between wholesale prices and volumetric retail rates (though any such comparison is often complicated by the existence of TOU pricing).

To illustrate these dynamics, we begin by focusing on a single representative utility, Public Service Company of Colorado (PSCo), and compare DPV customer-economics with and without NEM for four distinct commercial building types: a large hotel, supermarket, primary school, and warehouse. These four building types represent a wide cross-section in terms of two key attributes: their PV system hosting capacity and the coincidence between their load shape and PV generation profiles. For the first three of those building types, we assume PV systems are sized as large as the roof area feasibly allows, resulting in PV systems that meet the following percentages of each customer's annual consumption: large hotel (5.7%), supermarket (24.5%), and primary school (67.4%).[22] For the warehouse, roof space is not a binding constraint on PV system size, and we therefore assume instead that the system is sized to meet 100% of annual building load. For our initial set of comparisons, we assume all four customers are billed under PSCo's Secondary PV Time-of-Use (SPVTOU) rate, which has a demand charge and TOU-structured volumetric energy charges with a summer peak-period price of roughly $0.15/kWh.

As shown in Figure 9, the loss of NEM has no impact on payback periods for the large hotel and supermarket, as effectively no PV generation is exported to the grid at any time for either of those customers. For the primary school and warehouse, however, significant percentages of PV generation are exported, leading to increases in payback periods of roughly 1.5 years (12%) and 2.0 years (15%), respectively. Thus, the loss of NEM may impact commercial DPV customer-economics, but those impacts depend on the physical dimensions of the building relative to its load, and in some cases NEM may have no discernible effect.
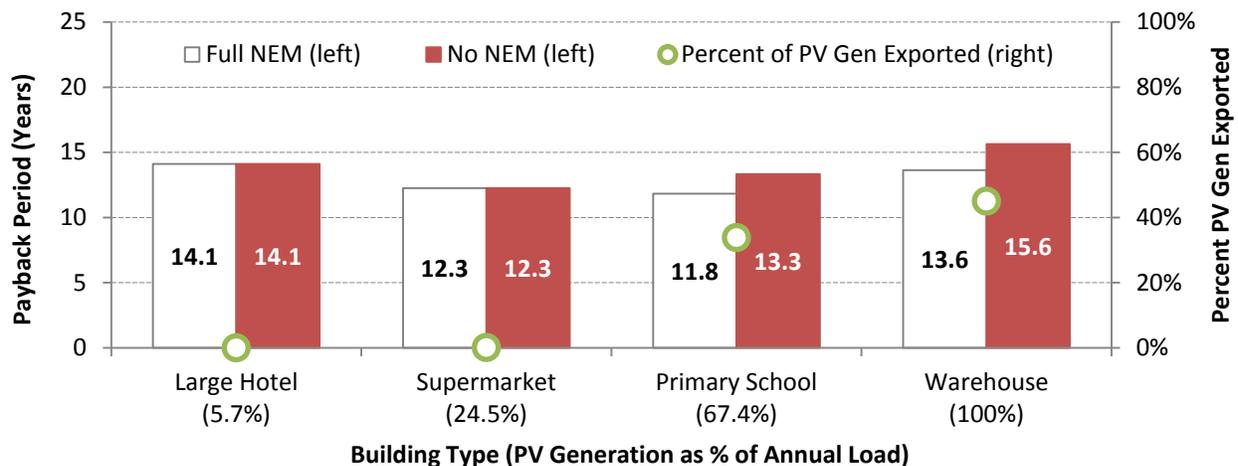
Figure 9. Impact of NEM elimination on commercial PV payback period (PSCo SPVTOU rate)

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[22] Assumptions about the PV hosting capacity of each customer type's roof space are based on the analysis in Davidson et al. (2015), and they are derived from DOE Reference Commercial Buildings.

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Retail rate structure is the other key consideration in assessing how an elimination of NEM could impact commercial DPV customer-economics. To illustrate this dependence, we consider a warehouse customer—again specifying a PV system sized to meet 100% of annual load—and compare payback periods with and without NEM across an illustrative set of commercial rate options. Specifically, we examine rate options offered by the four utilities identified in Table 1. For each utility, the rate options examined differ from one another in terms of either the relative balance of demand vs. volumetric energy charges and/or the temporal structure of the energy charges (flat vs. TOU). For each of the utilities, one of the two rate options, marked with an asterisk, is ostensibly more favorable to PV—either because of greater reliance on energy rather than demand charges and/or because of TOU rather than flat energy charges.

Table 1. Commercial Rate Options Analyzed

Utility	Rate Schedule	Demand Charge Size[a]	Energy Charge Size[†]	Energy Charge Structure
Florida Power & Light	GS-1[b]	None	Higher	Flat
	GSD-1	Higher	Lower	Flat
Rocky Mountain Power (RMP), Utah	Schedule 6	Higher	Lower	Flat
	Schedule 6a[b]	Lower	Higher	TOU, 7am–11pm peak
SCE	GS-TOU-2, Option B	Higher	Lower	TOU, 12–6pm peak
	GS-TOU-2, Option R[b]	Lower	Higher	TOU, 12–6pm "super" peak
SRP, Arizona	E-32[b]	Same	Same	TOU, 2–7pm peak
	E-36	Same	Same	Flat

GS = general service; GSD = general service demand

[a] Higher" and "Lower" describe the size of demand or energy charges relative to the size of the same charge on the other rate option shown for the same utility
[b] Indicates more-favorable rate for PV

As shown in Figure 10, the effects of NEM on commercial customer payback depend on the underlying rate structure. The two Florida Power & Light rate options, for example, differ only in terms of the relative balance between demand and energy charges. As shown, the loss of NEM leads to a roughly 1.2-year (14%) increase in payback period under the GS-1 rate but has no discernible effect under the GSD-1 rate. This is because volumetric energy prices under GSD-1 are effectively the same as the wholesale prices applied to exported PV generation when NEM is unavailable, while energy prices under GS-1 are higher and thus differ more significantly from wholesale prices. The same basic dynamic is illustrated by the pair of RMP rate options offered to customers in its Utah service territory. Little differential exists between wholesale prices and volumetric energy prices under Schedule 6, the high-demand charge rate, and thus the loss of NEM has virtually no impact on customer payback. Under Schedule 6a, however, demand charges are lower and volumetric energy prices correspondingly higher; a loss of NEM consequently would impact payback under that rate.

The other two pairs of two rate options illustrate how the existence of TOU pricing can complicate these dynamics, potentially in counterintuitive ways. Like the Florida Power & Light and RMP rate options, the two SCE rate options also differ in terms of the relative balance of demand vs. energy charges; however, the higher energy charges under Option R are primarily concentrated within the (relatively narrow) summer peak period. Because only a small fraction of PV generation occurs during that timeframe, the differential between wholesale prices and the average retail price received for exported generation via NEM is not much greater with Option R than with Option B. For similar reasons, we see relatively little difference between the two SRP rate options, in terms of how a loss of NEM would impact customer-economics. Although E-32 has TOU pricing and E-36 has flat rates, the average retail price received for grid exports via NEM is only marginally higher under E-32 than under E-36.
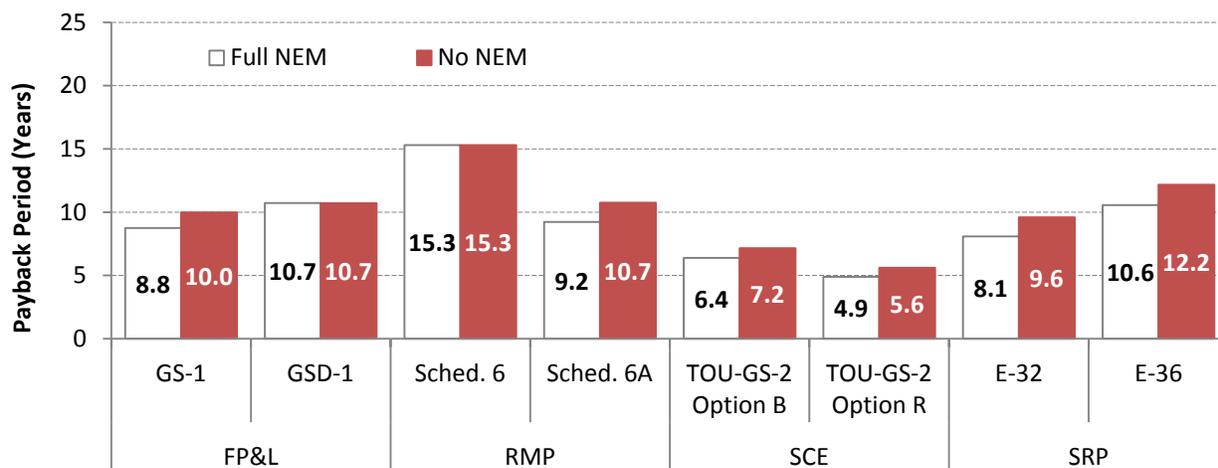
Figure 10. Impact of NEM elimination on commercial PV payback period (warehouse)

3.1.2 Impacts on DPV Deployment

Within the timeframe of the SunShot goals (2020), the most significant deployment impacts from any elimination of NEM are likely to be centered in states that reach their NEM program caps (though other states might also choose to eliminate or substantially alter existing NEM rules, as Hawaii has recently done). Most states with NEM (27 out of 44) have established some form of administrative cap on the maximum amount of DG that can enroll, often specified as a percentage of peak demand (Barnes and Haynes 2015). Current program caps range from a fraction of a percent to 5% or more of statewide peak demand, though definitions of peak demand can vary significantly (EQ Research 2015). These caps were typically included within the initial enabling legislation or regulations authorizing NEM, and they were intended to provide a stage-gate to ensure that regulators and other stakeholders would have an opportunity to reevaluate NEM to determine whether it remains an appropriate mechanism for compensating DPV. Depending on the state, enforcement and the ability to modify caps may be at the discretion of the PUC, which may be able to waive or raise the NEM program cap without new legislation or formal rulemaking.

As states have approached preexisting NEM caps, many raised those caps (often on multiple occasions) to avoid constraints on DPV market growth (Heeter et al. 2014). Going forward, though, appetite for further upward adjustments to NEM program caps is likely to wane, given

concerns among many utilities and regulators about revenue erosion from NEM and, in some cases, the physical impacts of DPV on distribution systems. As NEM penetration levels rise, existing program caps may therefore increasingly become binding in many states.

Heeter et al. (2014) compared NEM program caps in 10 states to forecasted NEM market growth and estimated that caps would be reached by 2019, if not sooner, in California, Delaware, Massachusetts, Nevada, New Jersey, New York, and Vermont. In Figure 11, we extend and update that analysis (in simplified form) to include all states with NEM program caps, drawing on data published by EQ Research (2015) for the percentage of each state's cap currently met and on the latest set of market forecasts from GTM Research and SEIA (2015).[23] Under those projections, current NEM administrative caps would be breached by 2020 (i.e., NEM penetration would exceed 100% of the caps, as shown in the figure) in at least 11 states, including the same seven states as found in the earlier analysis, plus Oregon, Louisiana, Washington, and New Hampshire. Although state-specific DPV forecasts are unavailable, Maine and Idaho would likely also reach their NEM caps by 2020, given current penetration levels.
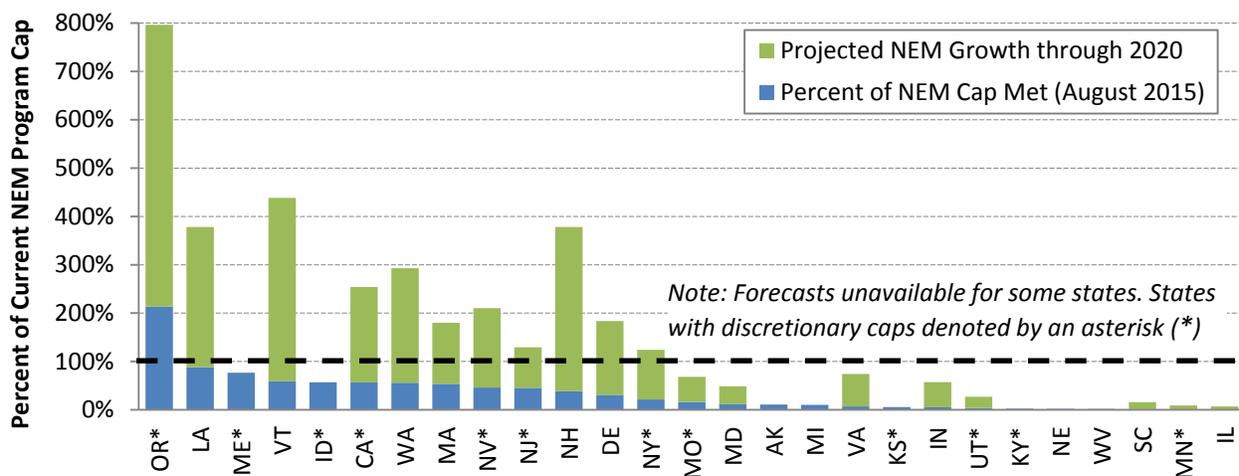
Figure 11. Projected NEM growth relative to current caps

Data sources: EQ Research 2015, GTM Research and SEIA 2015

The precise near-term impacts of NEM program caps on 2020 deployment levels cannot be readily estimated, given the discretionary nature of administrative caps in some states, the ability of state legislatures or regulators to revise caps, and inherent challenges in modeling deployment over short time-scales. However, as an upper bound, Table 2 shows the total "deployment at risk," based on the portion of forecasted DPV capacity growth in excess of NEM program caps in individual states.[24] These values represent effectively the maximum possible reduction in

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DPV deployment compared to current market projections, if one were to assume that no DPV is installed beyond each state's current NEM cap.

Based on this simple comparison of forecasted market growth to NEM caps, more than 14 GW of DPV, representing almost half of total projected U.S. DPV market growth through 2020, is at risk of curtailment owing to NEM program caps. The vast majority of that total is in California, which is currently engaged in developing a new set of NEM successor tariffs, which will be put in place once the existing caps are reached. Much of the remaining deployment at risk resides in other large DPV markets, particularly New Jersey, Massachusetts, and New York. Many smaller states, however, could also see severe constraints on growth, in relative terms, as indicated by the percentage of forecasted growth in excess of current NEM caps.

Table 2. DPV Deployment at Risk Owing to NEM Program Caps

	CA	DE	LA	MA	NH	NJ	NV	NY	OR	VT	WA	Total U.S.
MW at Risk through 2020	10,992	93	275	785	86	858	247	499	215	206	172	**14,428**
% of Forecasted Growth	78%	55%	96%	41%	82%	35%	67%	23%	100%	89%	82%	**47%**

To evaluate the potential longer-term deployment impacts of both existing NEM program caps and more-widespread movement away from NEM, we use NREL's dSolar customer-adoption model to project DPV deployment (residential and commercial) under three scenarios, including a current NEM policies case and two bounding scenarios[25]:

- **Scenario 1: Current NEM Policies.** NEM is assumed to continue in all states until program caps are reached, at which point compensation for exported generation is instead based on wholesale electricity prices.

- **Scenario 2: Immediate Elimination of NEM.** NEM is immediately eliminated in all states where it currently exists, and compensation for exported generation is instead based on wholesale electricity prices.

- **Scenario 3: Indefinite Extension/Expansion of NEM.** NEM is assumed to be available indefinitely to all customers in all states.

Key assumptions for this set of scenarios are as follows. In all cases, we assume SunShot cost targets are achieved in 2020 and thereafter remain constant in real dollars. We assume no major changes to underlying retail electricity rate structures or to technology characteristics, including integration of customer-sited storage. We assume no state incentives are available and that the federal ITC ramps down to zero for host-owned residential DPV systems and to 10% for non-residential systems and third-party owned residential systems by 2022, consistent with the ITC extension passed in late-2015. Systems are sized to meet a maximum of 75% of annual

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[25] The dSolar model is an extension of NREL's SolarDS model, used in the *SunShot Vision Study* (DOE 2012). Details about the dSolar model structure and logic are documented in Sigrin et al. (2016).

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consumption with NEM or 50% without NEM, subject to roof area constraints. These assumptions are not intended to represent most-likely future conditions; rather, they were selected to focus on the fundamentals of how NEM reforms could impact future DPV deployment. In discussing the results of this analysis, however, we describe how changes in some of these key assumptions might impact the findings.

We compare scenarios in terms of cumulative DPV deployment through 2050 and examine the two bounding scenarios in terms of the *difference* in cumulative deployment relative to the trajectory under current NEM policies. As shown in the left-hand panel of Figure 12, an immediate, across-the-board elimination of NEM would reduce DPV deployment, with greater impacts on residential than on non-residential DPV.[26] The effects would be relatively severe in the near-term, but they would decay over time as many states with NEM reach their administrative caps. Over the long run, an immediate elimination of NEM would reduce cumulative U.S. DPV deployment by roughly 20%, compared to projected deployment under a continuation of current NEM policies. Cumulative deployment in 2050 would be roughly 30% lower in the residential market and just 6% lower in the non-residential market. As discussed below, these effects may be either much larger or smaller in individual states.

Percentage Increase or Decrease in Cumulative DPV Capacity
Compared to Deployment under Current NEM Policies
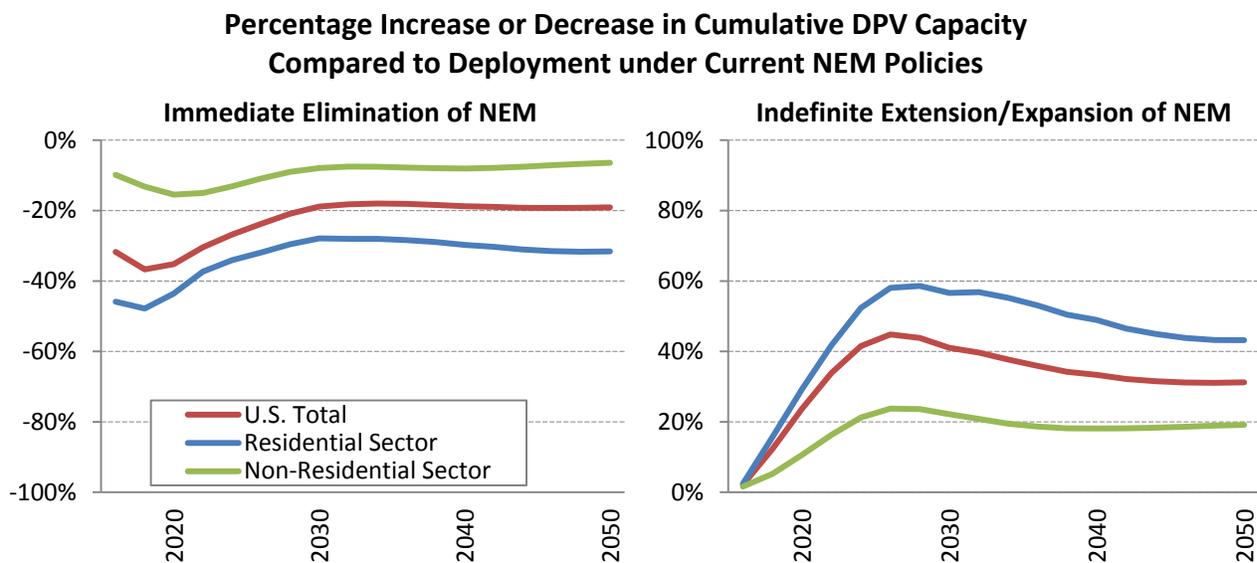
Figure 12. Impact of potential NEM reforms on projected DPV deployment over time

Conversely, an indefinite extension and expansion of NEM to all customers would increase DPV deployment, compared to the current mix of policies that include restrictions on NEM participation and program caps (see the right-hand panel of Figure 12). These effects vary over time: increasing in the near-term as markets currently without (or with soon-to-expire) NEM policies are opened and then declining over the long term as markets become saturated. Over the long term, universal NEM would result in roughly 30% greater U.S. DPV deployment in 2050,

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[26] The effects are greater on the residential market than on the non-residential market for the reasons discussed in Section 3.1: export quantities are generally higher for residential DPV, and residential retail rates rely more on volumetric charges.

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compared to current policies. As expected, the effects are greatest in the residential market, where cumulative deployment would be more than 40% higher than under current policies.

Naturally, the effects of extending or eliminating NEM will differ across states, depending on how significant a departure from current policies those scenarios represent. This is illustrated in Figure 13, which focuses on the 10 state markets with the greatest cumulative DPV deployment under current NEM policies, representing about two thirds of projected DPV capacity in 2050. Among these states, an immediate elimination of NEM (left-hand panel) would result in up to a 62% reduction in residential DPV deployment in 2050 and up to a 28% reduction in non-residential deployment. These effects are nonexistent or much smaller for those states currently without NEM (Texas, Georgia) or projected to reach their cap in the near future (California, New York, New Jersey, Louisiana). Conversely, those states with nonexistent or soon-to-expire NEM policies would see the greatest impacts from an indefinite extension or expansion of NEM, as shown in the right-hand panel. There we see up to 123% greater residential DPV deployment and 27% greater non-residential deployment than under a continuation of current policies. Those states that currently have NEM with no administrative cap naturally see no difference in deployment under this scenario, as it is effectively the same as current policy.

Percentage Increase or Decrease in 2050 Cumulative DPV Capacity Compared to Deployment under Current NEM Policies
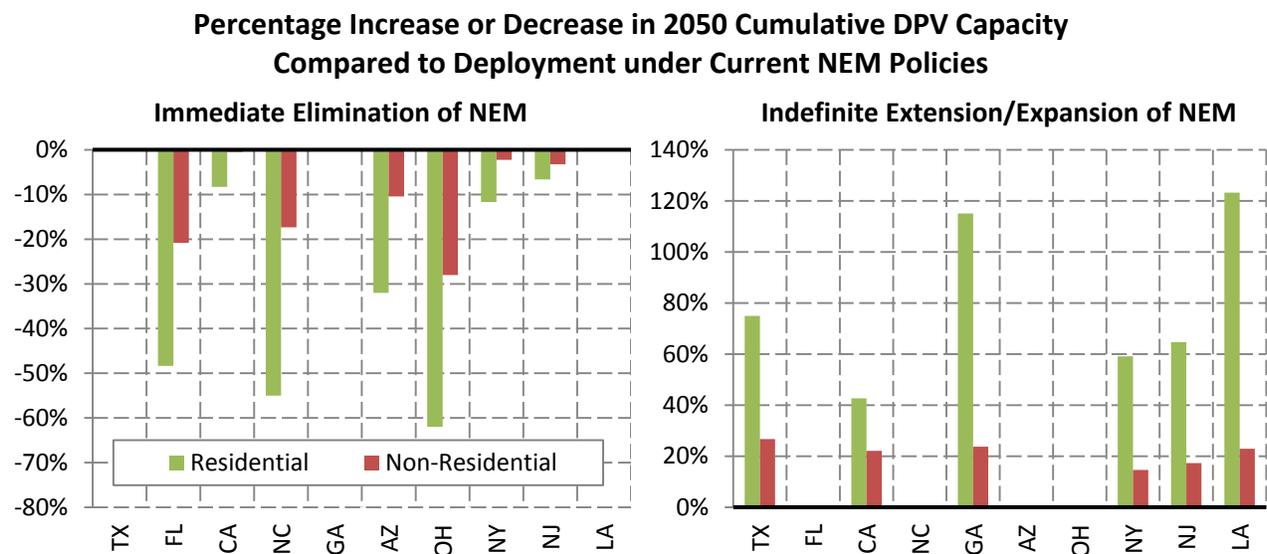
Figure 13. Impact of potential NEM reforms on projected 2050 DPV deployment by state

Importantly, the analysis presented here does not consider the potential for customers to add storage or shift consumption to minimize grid exports. As noted earlier, these kinds of strategies could mute the erosion of customer-economics that otherwise occurs with the loss of NEM, and they could thereby mitigate the deployment impacts. As one illustration of the potential mitigation, Dyson et al. (2015) forecast residential PV adoption in the Northeast under a scenario where exported generation is compensated at avoided-cost-based rates. They find that a combination of five demand-flexibility measures—including optimized control of electric water heating, space heating, dryers, EV charging, and battery storage—would increase cumulative PV deployment by 60% in 2030, relative to a case without demand flexibility measures (and accounting for costs associated with those measures). This is roughly similar in magnitude to the deployment effects estimated in the preceding analysis, suggesting demand flexibility could

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significantly mitigate the drag on DPV adoption that might otherwise occur if NEM were eliminated. Further analyses based on a consistent set of assumptions and methodology would be needed, however, to assess more precisely the interactions between changes in NEM policy and the integration of storage and other demand-flexibility measures with residential DPV.

One other important factor not considered in the analysis is the possibility of changes to retail rate design occurring in tandem with changes to NEM policy. Our analysis assumes that retail rate structures remain in their current form over the modeled timeframe. However, increased reliance on fixed monthly customer charges or residential demand charges would tend to compress the differential between volumetric retail electricity prices and wholesale electricity prices. As a result, not only would absolute deployment levels be lower across all three NEM scenarios evaluated, but also the differences between those scenarios would narrow. In other words, with a move toward greater use of fixed or demand charges, NEM becomes increasingly moot. Additional analysis would be useful for elucidating these dynamics.

3.2 Other Retail Rate Reforms and Alternatives to Traditional NEM

Moving beyond the threshold issue of whether NEM continues in its essential form or is replaced with an alternate form of compensation for exported generation, we turn now to the broader set of potential reforms to NEM and retail rate design, as described in Sections 2.3 and 0. In the discussion below, we describe the potential impacts of these other reforms on DPV customer-economics and deployment, drawing largely from existing literature—though in some cases reformulating or extending the results from those studies in ways that allow direct comparison. Where applicable, we also highlight key remaining analytical gaps.

3.2.1 Impacts on DPV Customer-Economics

Numerous studies have evaluated the impact of retail rate design on the customer-economics of DPV, typically by comparing the bill savings resulting from DPV under various rate structures in combination with NEM. Much of that literature has focused on time-varying pricing and demand charges, though several studies have considered two-way rates, fixed customer charges, or minimum bills. Other potential reforms—such as locationally varying pricing or unbundled pricing of grid services—have not yet been evaluated in terms of their effects on DPV customer-economics, though those impacts can be characterized in general terms. Furthermore, most studies have analyzed the impacts on DPV customer-economics without considering potential interactions associated with co-deployment of customer-sited storage or demand response.

Two-way rates. Two-way rates represent a direct alternative to NEM and to direct compensation for exported generation only. Under two-way rates, DPV generation is metered and compensated separately from electricity use. If compensated at a flat price per kilowatt-hour, such as through a VoS rate or FiT, determining the impact on DPV customer-economics is seemingly straightforward, simply requiring a comparison between the specified PV generation purchase price and the per-kilowatt-hour value of bill savings received via NEM. If the PV purchase price is higher than volumetric prices under the retail tariff, DPV customer-economics proportionally improve; if the specified PV price is lower than retail prices, DPV customer-economics proportionally worsen.

As noted earlier, many studies have sought to estimate the value of solar, and several meta-analyses have compared the results of those studies to average retail prices in each state, as a proxy for the value of bill savings received through NEM (Hallock and Sargent 2015 Hansen et al. 2013). Most studies have estimated a value of solar higher than average retail electricity prices, suggesting that a move to VoS rates would enhance the customer-economics of DPV. Among examples of specific VoS rates that have been implemented or proposed, however, the impacts are mixed, in some cases providing greater bill savings than NEM and in other cases lower savings. This occurs for the same reasons that VoS studies produce wildly divergent results—e.g., differences in methodology and the scope of benefits included, which in turn may reflect whether the study seeks to evaluate benefits only to the utility or to society more broadly.

For example, the VoS methodologies established by Austin Energy and the Minnesota Public Utilities Commission are both relatively inclusive in terms of the scope of benefits incorporated (Taylor et al. 2015). Austin's VoS rate is currently $0.107/kWh, which is roughly on par with prices for the highest usage tiers under its standard residential tariff, suggesting that many customers could receive greater bill savings under this rate than they would under NEM. At the other end of the spectrum, rates may be based solely on the value of avoided fuel or wholesale electricity market costs, which inevitably entails a substantial reduction in bill savings relative to NEM. For example, ASU-EPIC (2013) estimated that a 2013 proposal by APS would have resulted in roughly a 70% reduction in the bill savings from DPV, while Hyde (2013) estimated roughly a 56% reduction in bill savings if PV generation were compensated at PSCo's estimated value of DPV.

The effects on DPV customer-economics from moving to two-way rates can vary significantly across customers, depending on the rate structure offered in conjunction with NEM. Darghouth et al. (2010) evaluated the impact of moving to avoided-cost-based two-way rates for residential DPV customers in California. The results showed that the avoided-cost rates would universally erode the customer-economics, but the impacts depended highly on PV system size and customer usage level. For example, for a PG&E customer with median usage among the sample, the two-way rates resulted in a 40%–54% reduction in bill savings, depending on system size. However, given the steeply tiered volumetric rates that existed at the time, the bill savings for high-usage customers would be 55%–67% lower under the avoided-cost rates than with traditional NEM.

Finally, a transition to two-way rates could have several other kinds of impacts on DPV customer-economics, beyond the direct impact on annual bill savings. First, two-way rates might provide either greater or lesser certainty in compensation levels, relative to traditional NEM, depending on the period over which prices for any given customer are fixed. Second, direct payment for PV generation could create income tax burdens, though the U.S. Internal Revenue Service has yet to definitively rule on the subject (Hines 2015; Trabish 2014).

Fixed monthly charges. The impact of fixed monthly charges on DPV customer-economics depends on the size of the charge, whether the charge is applied to all residential customers or just those with DPV, and whether the charge is accompanied by a corresponding reduction in volumetric energy charges. McLaren et al. (2015) evaluated the bill savings for residential DPV customers when fixed monthly charges are added to their bills without a corresponding change in volumetric energy charges. This scenario might be considered akin to the imposition of standby charges or a per-customer, grid-connection fee assessed only on DPV customers. Focusing on a

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representative set of five utilities and a 5-kW residential system, they find that a $10 fixed monthly charge would reduce annual utility bill savings by 9%–18% across the five utilities, while a $50 fixed charge would reduce bill savings by 47%–90%.[27] An analysis of a recent $7 increase to monthly fixed charges in Wisconsin found that the corresponding reduction in volumetric rates would lead to a roughly 15% reduction in the bill savings from DPV, while a separate analysis of a hypothetical $10 increase in fixed customer charges in Massachusetts would increase the total bill for a representative residential solar customer by roughly 9% (Cornfeld and Kann 2014, Kann 2015a).

Minimum bills. For DPV customers, minimum bills have less impact on bill savings than do fixed customer charges of equivalent size, for two reasons: the volumetric energy price is largely unaffected, thus retaining the same value for offset consumption and exported generation, and, depending on the system size, the minimum bill provision may not be triggered in many months—indeed, a customer may install a smaller system to avoid triggering the minimum bill. To illustrate the potential impacts of minimum bills on DPV customer-economics, McClaren et al. (2015) considered residential DPV customer utility bills under several minimum bill levels. For a minimum bill set at $10/month, they found no impact on DPV bill savings for four of five utilities evaluated (and only a 2% decline in bill savings for the fifth utility). Raising the minimum monthly bill to $50 reduced DPV customer bill savings by 5%–48%, though this impact was still far smaller than the impact of a $50 fixed monthly customer charge, as described above. Confirming the same basic relationship, Cornfeld and Kann (2014) find that a $10/month minimum bill for a Massachusetts residential solar customer would result in just a 3% increase in the annual utility bill, compared to the 9% noted above for a $10/month fixed customer charge.

Demand charges. A fairly substantial literature exists on how the presence of demand charges can affect the bill savings generated from DPV. Most analysis to date has focused on the commercial segment, because demand charges have historically been most common for commercial customers, though several recent studies have considered residential customers in light of the growing interest in expanding demand charges to that segment. Collectively, these studies show that demand charges tend to erode the customer-economics, but DPV systems can reduce demand charges to varying degrees depending on several primary drivers: the particular customer load shape and its coincidence with PV production, the size of the PV system relative to the building's annual energy requirements, the specific design of the demand charge, and random variability in PV production associated with passing cloud cover or equipment failure. Key findings from related studies are as follows:

- Wiser et al. (2007) is one among several studies focusing specifically on commercial PV customers in California. They found that PV systems sized to meet a small portion of annual building load can effectively reduce demand charges; however, marginal demand charge savings decline rapidly with increases in system size as the customer's net load shifts to evening hours. Comparing across 20 commercial tariffs offered by the state's utilities with varying degrees of reliance on demand charges, they found virtually no difference in bill savings associated with the relative size of demand charges when PV systems were sized to meet just 2% of annual building load. In contrast, for systems sized

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[27] These percentage changes to annual bill savings were derived for the purpose of our analysis, based on the analysis performed by McLaren et al. (2015).

to meet 75% of building load, bill savings were roughly 50% lower on those rate options most heavily weighted toward demand charges, compared to rate designs with small or no demand charges. The study also highlighted the importance of demand charge design. Across a sample of customers, demand charge savings were 50%–400% larger if based on maximum demand during a weekday afternoon TOU period than if based on simply the maximum demand at any given point in the month. These differences across demand charge designs were most pronounced for customers with flat or inverted (i.e., evening peaking) load profiles.

- Ong et al. (2012) compared DPV bill savings for commercial customers across more than 200 rate options offered by roughly 50 utilities. For each rate option, they estimated bill savings for each of 16 standard commercial building load profiles, determining in each case the optimal PV system size to maximize bill savings. Among all permutations of rate options and customer load profiles, average bill savings were 13% lower for those rates with demand charges than for those without demand charges.[28]

- Ong et al. (2010) also compared bill savings across a broad set of commercial tariffs, though they focused more narrowly on a commercial office building with a PV system sized to meet 20% of its annual energy consumption. They found that bill savings declined almost in direct proportion to the size of the demand charges. For example, while the PV system reduced utility bills by roughly 21%, on average, for rates with no demand charges, bill savings declined to 12% for rates where demand charges constituted half of the pre-PV utility bill. A subsequent study by Ong and Denholm (2011) that focused on schools in California confirmed that bill savings were greater under rates with lower demand charges, though the researchers stressed that, given the specific set of rate options available, the options with higher demand charges may sometimes be the lowest cost.

- Davidson et al. (2015) compared commercial DPV customer-economics across building types and found that differences were largely a function of how well the PV system could reduce demand charges, given the coincidence between the building load shape and PV production profile. Among the particular building types evaluated, demand charge savings were greater for offices and schools, whose loads tend to have relatively narrow peaks in the afternoon, than for supermarkets and hotels. The study also highlighted the diminishing returns in terms of additional demand charge savings resulting from incremental increases in system size. Based on the example of a supermarket in Austin, their results show that a system sized to meet 10% of the building's annual energy needs would reduce demand charges by roughly 9%, but doubling the system size would result in only an additional 2% savings on demand charges.

- GTM Research (2013) compared the bill savings from PV between the two Southern California IOUs' standard commercial tariffs and their corresponding "PV-friendly" tariffs, which have relatively low demand charges. Based on a representative commercial customer whose PV system meets 75% of annual building load, bill savings under the standard commercial tariffs were roughly 30% lower than under the PV-friendly tariffs.

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[28] The numerical result reported here was derived from the complete set of results across all rate options included in the appendix of Ong et al. (2012).

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- VanGeet et al. (2008) presented a case study of two commercial PV facilities in San Diego, estimating monthly demand charge savings under several rate variations. In each case, the demand charge was based on maximum demand during a designated peak period, but the specific definition of the peak period varied among rate options. Across the various rate options analyzed, annual demand charge savings ranged from roughly 30% to 45%.

- Villaire and Lewis (2012) presented cases studies of three real-world commercial PV installations in Xcel Energy's Colorado service territory, showing in each case how various energy efficiency and demand management measures were implemented in conjunction with PV to reduce the customers' peak demand. Those peak demand reductions allowed the customers to become eligible for a rate option without demand charges, thereby maximizing the bill savings from their PV systems.

- Among the few existing studies to assess how demand charges impact residential DPV customer-economics, McLaren et al. (2015) estimated and compared annual bills for solar customers for five utilities that currently offer voluntary demand charge rates for residential customers. Based on a representative residential customer load profile for each region, they found varying results in terms of the absolute annual bill for DPV customers. In the most extreme case, the DPV-customer utility bill under the demand charge rate was roughly twice as high as under the standard rate, but in two cases there was virtually no difference between the two rate options, and in one case the utility bill under the demand charge rate was slightly lower than under the standard rate. Based on their results, we estimate the corresponding impacts on bill *savings* and find that, across the five utilities, the demand charge rates reduce bill savings by 36% to 55%.[29] One key methodological limitation noted within the study is that demand charges were estimated based on hourly average loads, whereas demand charges are typically assessed on average load measured over 15-minute or 30-minute intervals. Given the potential for sub-hourly variability in loads and PV generation, the analysis likely overestimates demand charge savings and thus understates the erosion of DPV bill savings. Most of the other analyses cited also relied on hourly data and are therefore subject to the same limitation.

- One of the more high-profile recent developments in rate design for residential DPV was the adoption, by SRP in Arizona, of a mandatory demand charge rate for residential customers with PV. The utility estimates that this rate will increase bills by roughly $50/month for a typical DPV customer if no actions are taken to reduce peak demand. A similar proposal by NV Energy to institute demand charges for new NEM customers would result in roughly a $37 increase in monthly bills for NEM customers, equivalent to a 37% reduction in monthly bill savings (NV Energy 2015).[30] A recent study by Rocky Mountain Institute (Dyson et al. 2015) considers how demand-flexibility measures could be deployed in conjunction with DPV to reduce demand charges under SRP's rate. The researchers focus on a customer with an EV, and they show that the utility bill increase

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[29] These derived results are based on the assumption that, prior to PV installation, customers choose the least-cost option between the standard rate and the optional demand charge rate. In every case, the demand charge rate was the lower-cost option prior to PV installation, based on the bill calculations in McLaren et al. (2015).
[30] The monthly impacts cited here were calculated from Table 3-5 in NV Energy's application (NV Energy 2015).

due to switching to the demand charge rate could be entirely offset through optimized control of EV charging, air-conditioning, and electric domestic hot water heating.

Time-varying prices. A sizable literature also evaluates the interaction between time-varying pricing and DPV customer-economics, mostly focused on TOU rates. In general, these analyses show that time-varying rates tend to increase bill savings for DPV customers, though various qualifications may exist. In particular, the extent to which time-varying rates benefit DPV economics may depend critically on wholesale electricity market dynamics, such as the presence of price caps, capacity markets, surplus generation capacity, or high levels of solar energy penetration. Moreover, even when time-varying rates generally benefit DPV customers, requiring all DPV customers to take service under time-varying rates can diminish the bill savings for certain customers, depending on system size and the shape of the customer load profile. Key findings from the existing body of literature are summarized below; where the same studies were referenced previously, refer to those earlier citations for relevant methodological details.

- Borenstein (2005; 2008) compared the bill savings received by PV systems under RTP rates and flat rates. When relying on simulated hourly prices that reflect a long-term equilibrium, the analyses found that hourly RTP rates provide roughly 30%–50% greater bill savings than a flat rate, across several California cities and system orientations. When using historical hourly wholesale electricity market prices rather than simulated prices, however, the relative advantage of RTP rates over flat rates was much lower owing to the existence of price caps and surplus generation capacity during the particular historical period from which the prices were drawn.

- Wiser et al. (2007) found that, across 20 different commercial rate options offered in California, bill savings were roughly 20% higher under TOU rates with the highest spread between peak and off-peak prices (roughly a ratio of 4.5:1), compared to flat rates with no temporal price differentiation.

- Bright Power Inc. et al. (2009) estimated bill savings for six commercial PV systems in New York, comparing between the available flat rate and RTP rate options. Across the six sites, the bill savings under RTP were found to be between 6% lower and 11% higher than under the flat rate. However, for most of the sites, the absolute bill level would be higher with the RTP rate, given the particular load profiles of the customers analyzed.

- Ong et al. (2012) found that, across a large number of commercial rates and building load profiles, bill savings were roughly 7% higher, on average, for rates with TOU pricing than for non-TOU rates. Ong et al. (2010) focused specifically on office buildings and found that, on average, bill savings were 10% higher on TOU rates than on non-TOU rates. However, that study also highlighted the importance of specific design features of the TOU rate, namely the timing of the peak period and the price differential between peak and off-peak prices. Among the TOU rates, bill savings were roughly 20% higher on the rate with a 6:1 ratio between peak and off-peak prices, compared to those with a ratio of just 1.5:1. There was a similar difference in bill savings between those TOU rates with peak periods correlating well with peak PV generation and those with the lowest correlation.

- Several studies focusing on residential rates in California have compared the bill savings that DPV customers would receive under the standard non-TOU rates and optional TOU rates offered by the state's IOUs. Darghouth et al. (2010) modeled utility bills for a sample of residential customers, across a range of PV system sizes. For PV systems sized to meet at least 75% of customer annual energy consumption, the TOU rates were almost universally lower cost than the non-TOU rates. However, for many customers with relatively small PV systems, the TOU rates resulted in higher bills than did the flat rate. Analyzing a similar data set of residential customers, but using earlier versions of the rate options, Borenstein (2007) found that most PG&E residential customers analyzed would be better off on the TOU rate option when installing PV. The opposite was true in the case of SCE's rate options, but for reasons unrelated to the TOU pricing structure. A similar analysis by MRW & Associates (2007) also showed that SCE's residential TOU rates were generally suboptimal for PV customers.

- Darghouth et al. (2013) compared residential DPV bill savings under flat, TOU, and RTP rates, across a range of potential future market scenarios, based on hourly load data for a sample of residential customers in California. Under a reference scenario, bill savings were roughly 13% greater with a TOU rate than with a flat rate. In contrast, the RTP rate yielded only marginally greater bill savings than the flat rate, because the vast majority of PV production occurred when hourly prices were low. Under a scenario with 15% PV penetration on the grid, wholesale electricity market prices were dramatically lower during times of solar production, and retail pricing under the TOU and RTP rates was correspondingly adjusted. As a result, bill savings under the TOU and RTP rates were roughly 20% and 30% lower than under a flat rate owing to the poor alignment between solar generation and high price periods. This erosion of customer-economics under TOU and RTP was less severe (though still present) under other high-renewables scenarios with a more balanced mix of solar and non-solar renewables and/or with storage or demand response resources that moderate the price decline during periods of solar generation.

3.2.2 Impacts on DPV Deployment

Projecting near-term deployment impacts from retail rate reforms is challenging, given the uncertain nature and extent of those reforms. For example, many states are considering increasing fixed monthly customer charges or instituting new charges on DPV customers, but it is unclear how many of those proposals will move forward, within what timeframe, and how large the charges ultimately adopted will be. It is also unclear how market participants would respond: for example, to what extent residential leasing companies would absorb any erosion in bill savings by reducing monthly lease rates quoted to prospective customers.

It is clear, though, that deployment impacts could be dramatic in individual utility jurisdictions if increased charges for DPV customers at some of the highest levels considered are adopted. Figure 14 shows the progression of PV interconnection applications in SRP's service territory over the period leading up to and following the adoption of demand charges for new residential DPV customers—which, by SRP's estimate, would add roughly $50 to the monthly bill of residential DPV customers that take no other action to reduce peak demand. As shown, the DPV market in SRP's service territory grew rapidly during 2014, but DPV growth essentially halted after the new rate design became effective at the end of that year. Even more-modest proposals

than SRP's could "tip the balance" in markets with marginal DPV customer-economics and dampen deployment over the near term. For example, Kann (2015a) shows that a recent $7 increase in fixed monthly customer charges in Wisconsin could delay grid parity for residential PV by several years or more in the state.

Salt River Power: Number of PV Interconnection Applications by Quarter
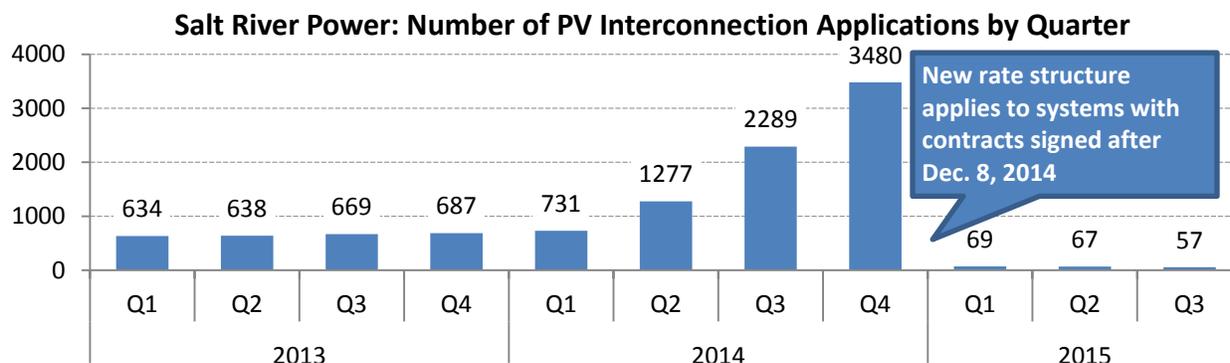
Figure 14. Impact of SRP demand charge rate on PV adoption

Data source: http://arizonagoessolar.org

Analyses of the deployment impacts due to other policy-related changes to DPV customer-economics are informative, in order to gauge the relative significance of changes to NEM and rate design for DPV customers. For example, GTM Research (2015) projects that the recent extension of the federal ITC will increase residential and commercial PV additions by roughly 40% through 2020, relative to what would have occurred had the tax credit expired in 2017, as previously scheduled. Considering that the ITC expiration would have likely increased DPV costs by around 10%–20% for a commercial or TPO residential PV project (Mueller and Ronen 2015; Mai et al. 2015), even seemingly moderate increases in monthly customer charges or new charges for DPV customers could yield a comparable impact on project benefits—e.g., a $5–$10 charge for customers otherwise receiving $50 in monthly bill savings from their PV systems. Though this is not a perfect analogy, it is easy to see that even incremental rate design reforms, if widely adopted, could significantly impact national deployment trends in the coming years.

To gauge the longer-term deployment impacts of rate reforms, Darghouth et al. (2015) projected PV deployment under a series of scenarios involving universal adoption of various NEM or retail rate reforms.[31] These include scenarios with varying increases in fixed monthly customer charges, two-way rates (e.g., FiTs or VoS rates) with prices either higher or lower than current retail prices, and time-varying retail rates. In developing these projections, the study accounted for two key feedback effects between PV deployment and retail electricity rates. The first of these is a fixed-cost recovery feedback, whereby increased PV deployment leads utilities to increase average retail prices to recover fixed costs. This is a positive feedback, because higher average retail prices tend to accelerate adoption. The second feedback is specific to customers on time-varying rates, and it accounts for the temporal shift in electricity prices as solar penetration on the grid increases. This is a negative feedback, because lower prices during periods of solar generation tend to dampen further solar adoption.

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[31] This analysis was conducted using NREL's SolarDS model, the predecessor to the dSolar model used for the deployment projections in Section 3.1.2. Given the different model used, as well as differences in key assumptions, some caution is warranted in comparing directly between these two sets of projections.

Figure 15, which adapts results from that study, shows the percentage change in cumulative DPV deployment relative to a reference case that assumes continuation of current rate structures and NEM rules. As shown in the upper left-hand panel, a uniform $50/month increase in fixed customer charges—which is accompanied by a corresponding decrease in volumetric energy rates—would reduce total U.S. DPV deployment by roughly 60% over the long run. Naturally, those effects are much more pronounced in the residential sector, where cumulative DPV deployment with a $50/month fixed customer charge is projected to be 80% lower than in the reference case. By comparison, a more-modest $10/month increase in customer charges would reduce cumulative deployment in the residential sector by roughly 20% from the reference case: still a significant impact, but certainly less severe.

Turning to the potential impacts from two-way rates, the middle row of panels in Figure 15 shows the changes in cumulative deployment under two illustrative pricing levels for PV output. At a price of $0.07/kWh for PV production, total U.S. DPV deployment would be roughly 80% lower than in the reference case over the long-term. Again, the impacts are most severe in the residential sector, where long-term deployment is projected to be 92% below the reference case. The commercial DPV market would also be diminished, by roughly 34% over the long run. At a price of $0.15/kWh for PV production—which is well within the range of many VoS estimates— total U.S. DPV deployment over the long run would be only marginally higher than in the reference case, though these effects vary substantially over time and across sectors. For residential customers, a flat $0.15/kWh price for PV generation would increase deployment most significantly over the short to medium term (i.e., through 2030), but the cumulative effects would decline over time as average retail electricity rates under the reference case rise.[32] For commercial customers, the effects are more complex, because most near-term commercial DPV adopters take service under TOU rates with relatively high peak-period prices, and those rates combined with NEM provide more attractive customer-economics than a flat $0.15/kWh two-way rate. Pricing all commercial DPV generation at $0.15/kWh would therefore reduce deployment in the near term, though over time those effects would be outweighed by increased commercial deployment in other regions with less dramatic TOU peak-period pricing.

Finally, the bottom row of panels in Figure 15 shows the deployment impacts associated with widespread movement toward TOU pricing. In the near term, universal adoption of TOU pricing is projected to increase deployment above what would occur in the reference case, with almost 20% greater deployment in the early years of the next decade. Over the longer term, however, TOU rates become progressively less attractive to DPV customers, given the shift of peak prices into evening hours. As a result, cumulative U.S. DPV deployment in the later years of the forecast period is roughly 20% below what would occur under a continuation of the current mix of rate structures. The same general dynamic—i.e., higher deployment in the near term and lower deployment over the long term—occurs in both the residential and commercial segments, but it is notably less pronounced for commercial customers because many already take service under TOU rates in the reference scenario.

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[32] This particular dynamic is not inherent to two-way rates, though under a VoS tariff one might anticipate a similar outcome, given the declining marginal value of solar at higher penetration levels.

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This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.
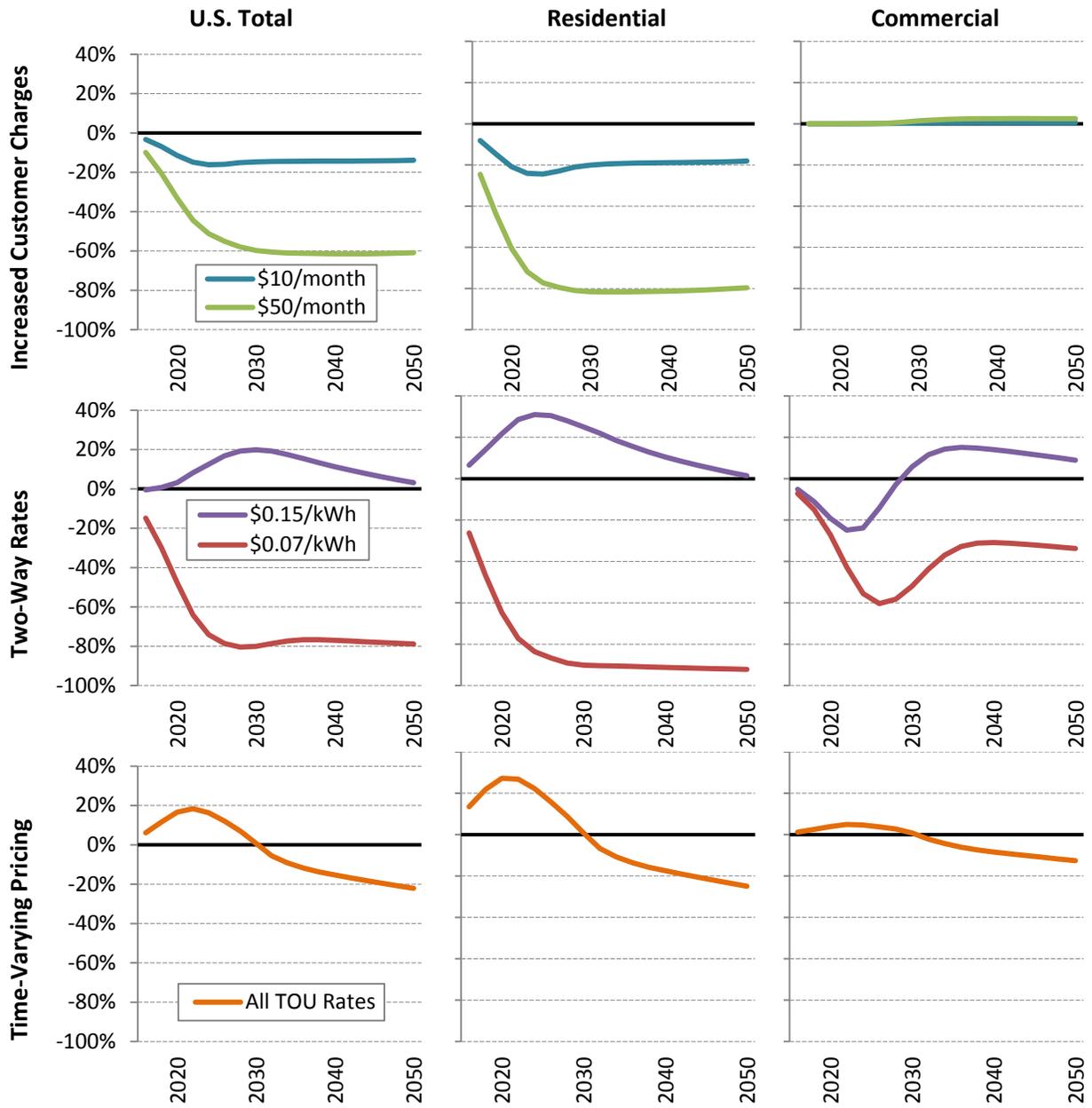
Figure 15. DPV deployment impacts of various retail rate and NEM reforms

Data source: Darghouth et al. 2015

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4 Other Utility Regulatory and Business Model Reforms and Implications for DPV Markets

This report is focused on utility regulatory and business model reforms that have direct implications for DPV markets and for achievement of the SunShot Initiative goals. As previously noted, those reforms are motivated by a diverse set of underlying drivers, including concerns about cost-shifting among customer classes and erosion of utility profitability resulting from the growth of DPV (and DER more generally). Sections 2 and 3 focus on one subset of the reforms intended to address those concerns—namely changes to NEM and retail rates. In one sense, these are relatively low-hanging fruit, because they generally can be implemented through traditional ratemaking processes and, in many cases, involve only incremental changes to existing rate design. However, they represent largely a zero-sum game: to the extent they mitigate any erosion of utility shareholder value or cost-shifting caused by DPV, they tend to do so by reducing the economic returns to DPV customers and restricting future DPV deployment.[33]

A much wider set of reforms is also under active consideration in a number of states or has been suggested more generally. These reforms offer opportunities to address utility shareholder and/or ratepayer concerns about DPV growth without necessarily constraining DPV customer-economics and deployment (though they may entail other tradeoffs). These reforms, each discussed further throughout the remainder of this section, include the following:

- **Ratemaking reforms to reduce regulatory lag:** Revenue decoupling, lost-revenue adjustment mechanisms (LRAMs), and other reforms to utility ratemaking practices can reduce the lag between when retail electricity prices are established and when they are applied. By doing so, these measures can alleviate the effects of DPV growth on utility shareholder ROE.

- **Enhanced utility system planning:** Reforms to utility planning processes—particularly for the distribution system, but also for generation and transmission—offer opportunities to direct DPV deployment in ways that enhance its value to the utility system and, in so doing, counterbalance the effects of revenue erosion on utility shareholder ROE and on non-solar customer rates.

- **Utility ownership and financing of DPV assets:** Though contentious for various reasons, allowing utilities to own or finance DPV assets and to rate-base those costs offers utility earnings opportunities to offset earnings foregone by the deferral or displacement of traditional utility capital investments due to DPV. Utility ownership might also address concerns related to cost-shifting and ratepayer equity, by focusing on high-value DPV deployment and expanding access to hard-to-reach customer segments.

- **Shared solar:** Shared solar offers several pathways to potentially alleviate some of the stakeholder concerns related to traditional rooftop DPV with NEM. In particular, it provides one specific (and limited) opportunity for utility ownership or financing of PV assets. It can expand customer access to solar, if designed for that purpose, and thus

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[33] This characterization is not absolute. For example, as discussed in Sections 2 and 3, time-varying pricing or unbundled pricing might offer DPV customers the opportunity for returns on par with those achieved under current NEM rules and rate designs, though that parity would likely depend on changes in how DPV systems are designed and deployed.

dissipate some of the concerns surrounding ratepayer equity. It also may allow for bill credits to participating customers that are below full retail rates, limiting utility revenue erosion while potentially maintaining customer-economics on par with rooftop PV and NEM.

- **Performance-based regulation and incentives:** Like decoupling and other reforms that focus on reducing regulatory lag, certain forms of PBR may also mitigate the impacts of DPV on utility shareholder profitability by helping to sever (or loosen) the linkage between utility profits and sales. However, performance incentives might go beyond mitigating shareholder losses by creating positive earnings opportunities through performance goals linked to facilitating DPV market development.

- **Broader business model and market reforms:** A variety of other, even more far-reaching reforms to utility business models and electricity markets have been articulated in the literature and within the context of specific state regulatory proceedings. These include the transformation of today's electric utilities into energy service utilities, formation of distribution network operators, and creation of transactive retail electricity markets. Although these concepts are still largely theoretical in nature, they might address some of the current concerns related to the financial impacts of DPV on utility shareholders or ratepayers, by realigning utility profit incentives in ways that are compatible with DPV growth and/or by stimulating higher-value forms of DPV deployment that alleviate cost-shifting across customer classes.

Many of the abovementioned reforms are already well established or build upon established processes, and these could be rolled out more widely within a relatively short timeframe. Others, particularly those involving broader business model and market reforms, may require longer lead times, and their effects may not materialize until well beyond the timeframe of the 2020 SunShot cost targets. That said, longer-term business model and market reforms—which several states are currently pursuing proactively—could profoundly influence the ultimate impacts and legacy of the SunShot Initiative.

In this section, we elaborate on the set of utility regulatory and business model reforms listed above and, drawing upon existing analyses, discuss and illustrate how they may address present concerns surrounding the impacts of DPV growth on utility profitability and on non-solar customers. Where possible, we highlight examples or emerging practices, including international experience, and note relevant tradeoffs and other considerations. Given the complexity and variety of this set of reforms, our discussion is far from comprehensive. Rather, it is intended to provide a framework for the kinds of strategies—beyond retail rate and NEM reforms—that are currently under consideration and may address existing utility concerns about DPV.

4.1 Ratemaking Reforms to Reduce Regulatory Lag

Under traditional COS regulation, utility rates are established through periodic rate cases and are based on costs and sales from a specific test year. Actual achieved utility shareholder returns are then a function of the relative growth of sales and costs in the intervening years between rate cases. Utilities that maintain cost growth at levels below sales growth are able to exploit this "regulatory lag" in the ratemaking process—that is, the delay between a change in costs or revenues and a change in authorized prices—and potentially earn returns above their authorized levels (Beecher 2015). Conversely, activities that reduce sales growth without a commensurate

impact on cost growth will tend to reduce utility shareholder profitability. This is known as the "throughput incentive" and has long been acknowledged as a key barrier to utility support of energy efficiency programs (Eto et al. 1994 RAP 2011). The same dynamic occurs in the context of DPV, as shown earlier in Figure 2, where modeling by Satchwell et al. (2014) illustrated how high penetrations of DPV could reduce utility shareholder ROE.

Various mechanisms have been proposed, and in many cases implemented, to reduce regulatory lag in traditional utility ratemaking and, in so doing, alleviate the impacts of energy efficiency or DPV on utility profitability. One of the most often cited is decoupling, which severs the link between a utility's revenues and its sales of electricity. Currently, 15 states have some form of revenue decoupling for electric utilities (Gilleo et al. 2015). A more limited alternative to decoupling is a lost-fixed cost recovery mechanism or LRAM. Rather than entirely severing the link between utility profits and sales, these mechanisms instead "reimburse" the utility only for the lost contribution to fixed costs resulting from energy efficiency programs. Fourteen states currently have some such mechanism available for electric utilities, and similar approaches conceivably might be extended from energy efficiency to DPV (Gilleo et al. 2015). Numerous other mechanisms have also been used to reduce regulatory lag, though typically they are not so closely associated with energy efficiency; these include more-frequent or multi-year rate cases, use of current or future test years, cost trackers and pass-through surcharges, and formula rates, to name a few (e.g., Beecher 2015; Carter 2001; Coffman 2015; Lowry et al. 2013).
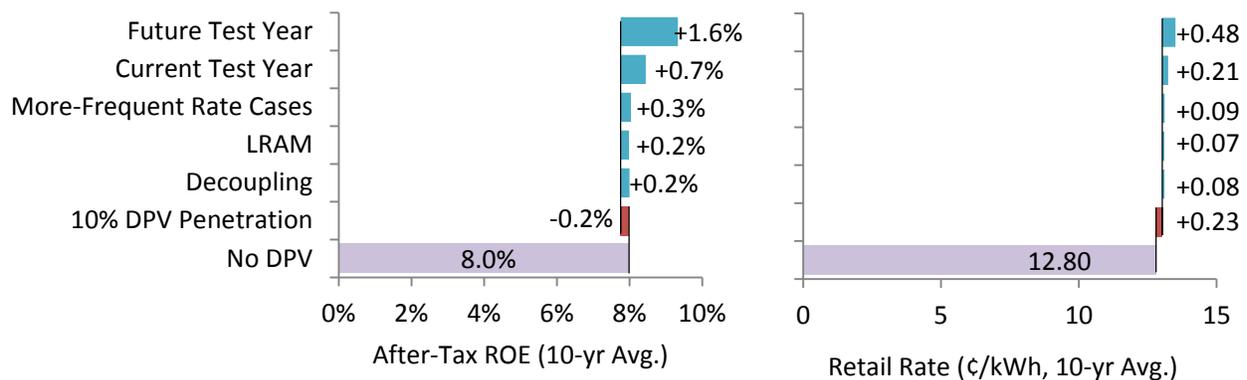
Figure 16. Impacts on utility ROE and average rates from reducing regulatory lag (prototypical Southwestern utility)

Data source: Satchwell et al. 2014

Measures such as these could stem the erosion of utility shareholder profits that might otherwise occur as a result of DPV growth under more-traditional ratemaking practices. For example, Satchwell et al. (2014) modeled a prototypical Southwestern utility and found that, under traditional COS ratemaking practices, increasing DPV penetration to 10% of utility sales led to a roughly 0.2% (20 basis point) reduction in average utility shareholder ROE (see left-hand panel in Figure 16). However, those effects could be largely, if not entirely, offset through the use of decoupling, LRAM, more-frequent rate cases, or current or future test years. Although similar mitigations could be achieved through broader application of fixed charges, for example, decoupling and the other mechanisms shown here do so without dampening the customer-economics of DPV, energy efficiency, or other behind-the-meter resources.

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To be sure, decoupling, LRAM, and other mechanisms for reducing regulatory lag come with their own controversies and objections, including the shift in risk from utility shareholders to ratepayers that diminishes utility incentives for cost control (Beecher 2015). Moreover, within the context of addressing stakeholder concerns about the financial impacts of DPV, these approaches focus narrowly on mitigating the effects on utility shareholder ROE; they do not fundamentally address the potential impacts to non-solar ratepayers. Under traditional ratemaking processes, the impacts of revenue erosion from DPV fall almost entirely on utility shareholders during years between rate cases, and only after new rates are established in the next rate case are non-solar ratepayers impacted. Reforms to reduce regulatory lag effectively push revenue-erosion effects immediately onto ratepayers, accelerating any cost-shifting from DPV. In the analysis by Satchwell et al. (2014), for example, decoupling resulted in an additional $0.0008/kWh (0.6%) increase in average retail rates for the prototypical Southwestern utility, as shown in the right-hand panel of Figure 16. Another analysis by Shirley and Taylor (2009), focusing on a utility in the Mid-Atlantic with more-modest levels of DPV growth, estimated that decoupling would lead to roughly a $0.0001 to $0.00025/kWh increase in residential retail rates.

4.2 Enhanced Utility System Planning

In traditional distribution system planning, electric utilities assess the need for system upgrades by: (1) estimating the projected peak load growth over a 3–5 year period, (2) designing infrastructure to accommodate any projected increases in peak load, and (3) installing the necessary equipment (Cleveland et al. 2015). This process has long been focused narrowly on meeting peak load, the single highest projected demand on a distribution feeder in a given year. This narrow scope of analysis and action has prevailed for so long that the process is often conducted on a completely internal basis within the distribution utility company, with no outside stakeholder involvement. Moreover, capital investments in distribution upgrades resulting from this planning process commonly are considered to be the normal course of the utility's business and frequently do not require formal prudency review for cost recovery within the general rate case (Cleveland et al. 2015).

Growing levels of DPV deployment in a number of regions have prompted reforms of distribution system planning processes to more proactively anticipate and direct DPV growth. Although these processes are primarily about managing the physical impacts of DPV on utility systems, they can also help to mitigate concerns related to the financial impacts of DPV on utility ratepayers, by facilitating grid-friendly DPV deployment that offers greater value and imposes lower costs on the utility system and its customers. In part, this can occur by directing DPV deployment toward specific locations on the distribution network. For example, Edge et al. (2014) identified a range of mechanisms by which utilities could locationally target DPV deployment, including increased public information on distribution feeder hosting capacity, targeted interconnection processes, locational incentives, locational interconnection costs, locational pricing, and targeted distribution system upgrades.

Distribution system planning processes can provide the foundation for such locational targeting mechanisms and, for any given location, can identify DPV system characteristics (e.g., orientation and inverter functionality) that optimize DPV's value to the utility system. Transmission system and utility resource planning processes can serve a similar function, by

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directing DPV and other DER development toward transmission-constrained load pockets that would otherwise require transmission upgrades or new generation capacity to meet load growth.

Within the context of efforts to address the impacts of DPV on utility shareholders and non-solar customers, improved utility system planning holds promise as one strategy for rebalancing the underlying revenue and cost impacts. As an illustration, Satchwell et al. (2014) modeled the impacts of DPV with NEM under a range of assumptions about its underlying value to the utility—specifically, in terms of its impact on T&D and generation capacity costs. In the low-value case, DPV leads to higher distribution system costs for network upgrades, does not defer any T&D capital expenditures, and has minimal ability to defer generation capacity additions. In the high-value case, DPV does not impose any distribution network upgrade costs, has some ability to defer T&D capital expenditures related to load growth, and has a relatively high capacity credit for generation capacity deferral.

Figure 17 shows how the impacts from DPV at a 10% penetration level vary across these avoided-cost assumptions for a prototypical, vertically integrated utility in the Southwest. With low levels of avoided costs, DPV results in more than a 5% decrease in shareholder ROE and more than a 4% increase in average retail electricity prices. However, with higher avoided costs—as might be facilitated through proactive distribution system planning—DPV leads to just over a 2% decrease in shareholder ROE and a slight decrease in average retail rates. Although the particular range of assumptions explored through this analysis was primarily meant to characterize uncertainty in the capacity value of DPV, the analysis also illustrates how efforts to direct DPV deployment in ways that enhance its value to the utility system—whether through improved planning or other means—can reduce the effects of revenue erosion on utility shareholders and potentially even eliminate any cost-shift to non-solar customers.
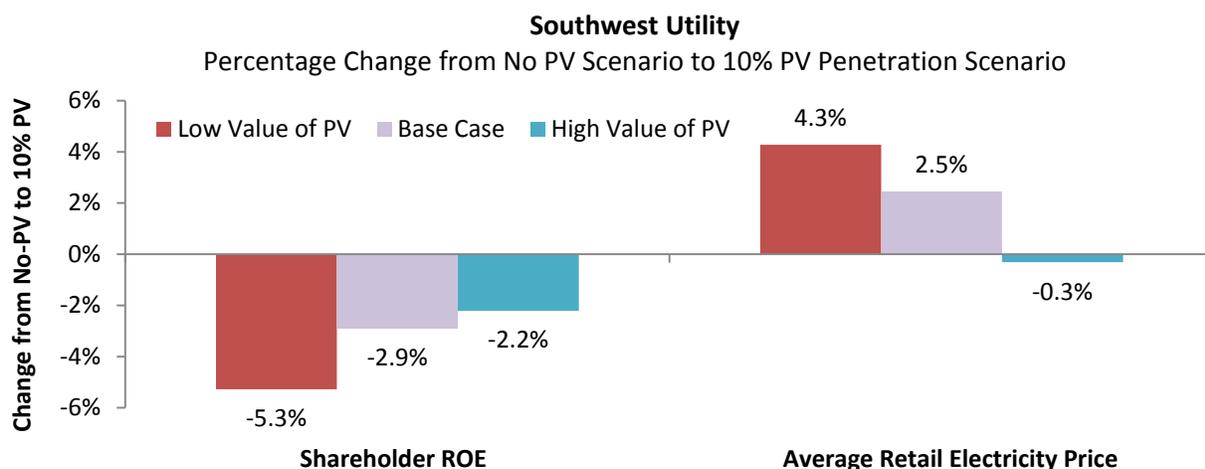
Figure 17. Sensitivity of shareholder ROE and retail rate impacts to avoided generation capacity and T&D costs from DPV

Data source: Satchwell et al. 2014

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Several recent documents have supplied conceptual frameworks for changes to distribution system planning practices. The Interstate Renewable Energy Council (IREC) first introduced the concept of Integrated Distribution Planning (IDP) in a May 2013 concept paper (Lindl et al. 2013). This approach consists of the five steps outlined in Figure 18, which include estimating the DG hosting capacity of individual distribution circuits in advance of any particular interconnection request, identifying upgrades necessary to accommodate further DG growth, and publishing information about available interconnection capacity. One of the major aims of IDP is to improve decision making by utilities and DG participants. For example, the preemptive evaluation of hosting capacity allows longer lead times for utilities to complete analysis, planning, design, procurement, and installation of necessary equipment. Similarly, the publication of hosting capacity data in Step 5 allows DG providers to avoid areas where they are likely to trigger costly capital upgrades, instead directing customer acquisition and project development toward areas where capacity is readily available. Recent innovations in distribution system planning processes in Hawaii and California incorporate some or all of these steps (see Text Box 4 and Text Box 5).
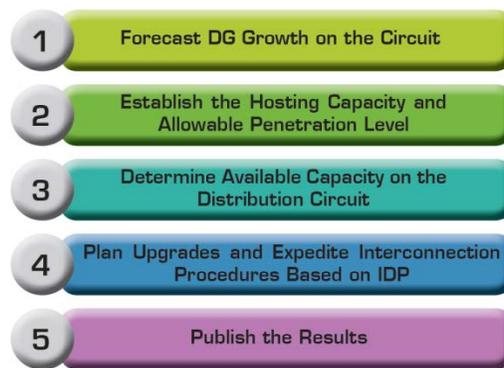
Figure 18. IREC's IDP framework

Source: Lindl et al. 2013

Another important contribution to the development of innovative distribution system planning is the Electric Power Research Institute's (EPRI's) Integrated Grid project, which highlighted the need for a holistic approach to incorporating DERs more fully into grid planning, operations, and compensation schemes. With regard to distribution system planning, in particular, one particular report (EPRI 2014) highlighted issues that arose within the context of rapid growth of DPV in Germany, where the traditional distribution planning processes initially did not anticipate local voltage and system stability concerns, ultimately requiring retrofits of protection and voltage control equipment as well as retrofits and adjustments to inverter set points.

Finally, several workshops in California on system planning yielded the "More Than Smart" framework in 2014. A white paper summarizing this framework touches on topics of distribution system planning, design-build, operation, and DER integration (DeMartini 2014). The paper emphasizes the importance of developing a system for locational valuation of DERs within the distribution system planning process. This information can then be used by utilities to compare the value of alternative fleets of utility DERs and could form the basis for locational or unbundled pricing for DER providers.

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Text Box 4. Hawaii's Emerging Distribution System Planning Practices

With the highest penetration of DPV relative to peak demand in the United States, Hawaii was one of the first jurisdictions to confront the shortcomings of the traditional distribution planning process for integrating DER. The initial work on a new distribution system planning process was conducted by the Reliability Standards Working Group (RSWG) and culminated in the Independent Facilitator's Final Report to the Hawaii PUC in March 2013, in which the RSWG defined a "Proactive Approach" to distribution planning (Silverstein 2013). The proposal largely targeted IDP analysis and reviews into the interconnection study process for distributed generators on the HECO system. The basic structure of the Proactive Approach entails consolidating all interconnection requests into a single queue, forecasting anticipated additions to the queue over the following year, assessing the ability of feeders to accommodate the queued and forecasted interconnection requests, calculating the remaining available capacity of feeders, and informing queued requests of the available capacity on their targeted circuit or, alternatively, upgrades required to accommodate their request.

This approach was ultimately endorsed by the Hawaii PUC, which then required the HECO companies to develop and submit a comprehensive Distributed Generation Interconnection Plan (DGIP). The PUC directed the HECO Companies to include several elements in their DGIP. These include: (1) a Distributed Generation Interconnection Capacity Analysis to proactively assess the capacity available to interconnect DG on a circuit-by-circuit basis; (2) an Advanced DER Technologies Utilization plan to assess the ability of advanced inverters, storage, demand response, and EVs to mitigate adverse grid impacts from high DER penetration; and (3) a Distributed Circuit Improvement Implementation Plan to outline steps to increase the hosting capacity of the grid for additional DER.

HECO submitted its DGIP in late August 2014 in response to the Hawaii PUC's order. To fulfill the Distributed Generation Capacity Interconnection Analysis requirement, HECO presented a cluster evaluation methodology, under which it evaluated three representative clusters of feeders in terms of several key metrics related to DG hosting capacity: contribution to fault current, voltage fluctuations, load tap changer cycling, and real power back-feed conditions at substations (Nakafuji et al. 2014). This methodology, once applied to all HECO feeders, is intended to expedite the interconnection study process, as DERs proposed for unconstrained feeders could be quickly approved. The process also highlights to distribution engineers which feeders are or are soon to be constrained with respect to DG hosting capacity, so the engineers can plan distribution system upgrades to mitigate these conditions.

Text Box 5. California's Emerging Distribution System Planning Practices

California's current distribution resource planning process stems from Assembly Bill 327, passed in 2013, which obligated electric utilities to develop distributed resources plans (DRPs) (Perea 2013). The statute requires that plans evaluate locational benefits and costs of DERs on the distribution system, identify standardized contractual arrangements to facilitate cost-effective deployment of DERs, propose ways to coordinate DER deployment across the many CPUC-approved programs, identify additional capital spending necessary to facilitate further DER deployment, and identify barriers related to the deployment of DER. In an indication of increasing public interest in distribution planning, the bill also required any capital spending proposed in utilities' DRPs to be entered into their next general rate case for review and approval, rather than counting such upgrades as a regular cost of business.

In its subsequent guidance on the DRPs, the CPUC presented three high-level goals for the plans: modernize the distribution system to accommodate two-way energy flows, expand customer choice for energy technologies and services, and create opportunities for DERs to deliver grid services (CPUC 2015a). The guidance document required several key elements within each utility's DRP, including an Integration Capacity Analysis and a Locational Benefit Analysis (CPUC 2015a). The Integration Capacity Analysis is a proactive evaluation of the available hosting capacity of every feeder in a utility service territory, taking into account constraints such as thermal ratings, protection system limits, power quality, safety standards, and planned system upgrades over the subsequent 2 years. Similarly, the Locational Benefit Analysis provides locationally differentiated values for DER at a very granular geographic scale. Other required elements included feeder-level DER growth forecasts and proposals for several demonstration and deployment projects to leverage the above analysis and data. California's three IOUs filed their plans with the CPUC in 2015, and they published interactive web-based maps to display the results of each Integration Capacity Analysis (CPUC 2015c).

One commonality between the California and Hawaii processes is the goal of improving customer and DER-developer decision making through the publication of available interconnection capacity data. Hawaii generates this information on a rolling basis and allows customers to input their street address to determine the available capacity on their local feeder. This effort avoids the situation in which a customer submits an interconnection request without knowing if the interconnection is on a constrained feeder. Similarly, the California IOUs' public and regularly updated interconnection capacity maps make clear which feeders have available capacity and which are potentially constrained, allowing developers to target customers or sites on unconstrained circuits.

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4.3 Utility Ownership and Financing of DPV Assets

Another recent development in the DPV space has been the growth of utility programs to directly own and operate DPV assets, which may come in many varieties (Wiser et al. 2010). Ownership may reside either with the regulated utility or its unregulated affiliate. Programs may be focused on residential rooftop systems—as with recent pilot programs launched by utilities in Arizona, Texas, and New York (see Text Box 6)—or on larger commercial rooftop systems or distributed projects at utility substations, as with earlier programs by several California IOUs (Nimmons and Taylor 2008). One limited form of utility ownership of DPV assets would extend only to the inverter (Davidovich and Sterling 2014). One other alternative to outright ownership is for the utility to provide financing for customer investments in DPV—similar to on-bill financing programs that many utilities offer for energy efficiency investments—as New Jersey distribution utilities have done (Newcomb et al. 2013). Finally, rather than project-level investments, utilities' unregulated affiliates or parent companies have in some cases provided tax-equity financing to DPV project developers and made other investments in the solar sector.

From the perspective of ameliorating the financial impacts of DPV on utilities, a primary benefit of utility ownership is to offer a positive earnings opportunity to utilities, compensating for earnings erosion that might otherwise occur when DPV defers traditional utility capital investments. As an illustration, Satchwell et al. (2014) modeled the earnings impacts of utility ownership of DPV for two prototypical utilities. Under a scenario with total DPV penetration reaching 10% of utility retail sales, they consider two levels of utility ownership: either 10% or 100% of all DPV capacity. As shown in Figure 19, the earnings impacts are particularly pronounced for the prototypical Northeastern utility—a wires-only utility with otherwise limited earnings opportunities. Utility ownership of 10% of the DPV in its service territory offsets most of the earnings erosion that would occur as a result of DPV with no utility ownership. For the prototypical Southwestern utility, which has a proportionally much larger rate-base, the earnings impacts are less dramatic, though still potentially significant.
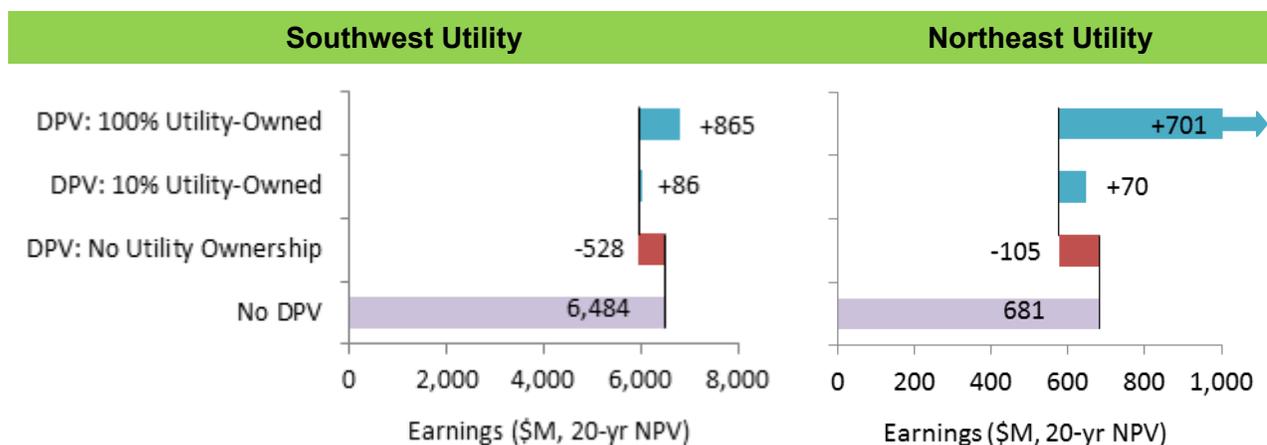
Figure 19. Increased utility earnings through DPV ownership

Data source: Satchwell et al. 2014
NPV = net present value

While the additional earnings opportunities may address certain concerns about DPV from the perspective of utility shareholders, utility ownership of DPV within the utility's own service territory may also offer certain opportunities to mitigate concerns about cost-shifting to non-solar customers. First, utility ownership of DPV assets may provide one pathway to facilitating high-value modes of deployment. This could involve targeting specific locations where DPV provides exceptional value or low interconnection costs, preferentially deploying systems with grid-friendly designs, or integrating control of DPV inverters into utility operations and grid management. As discussed previously in connection with Figure 17, higher-value forms of deployment benefit ratepayers at large, reducing any rate impacts and cost-shifting associated with NEM or DPV more generally. Second, utility ownership of DPV has also been suggested as one approach to expanding access to hard-to-reach customer segments, and this has been a key selling point of many recent utility pilot programs. Although efforts to target low-income customers, those with low credit scores, or other specific underserved markets do not directly address possible broader cost-shifting from DPV, they may help to quell concerns about potentially regressive effects of NEM.

To be sure, direct ownership of DPV assets by regulated utilities attracts criticism (Tong and Wellinghoff 2015b). For example, many in the solar industry have objected to entry into a competitive market by an entity that also operates a monopoly business with guaranteed cost recovery and that controls key processes and information essential to the deployment of distributed solar. In addition, some critics have characterized investments in DPV outside of utilities' traditional core business as an unnecessary risk that ratepayers should not be forced to bear, particularly when the benefits accrue primarily to one set of customers, and that shareholders may similarly be loath to accept. Other potential concerns include whether utility ownership is the least-cost option for ratepayers and whether additional utility capital investments would only further exacerbate cost-recovery problems. The viability of utility ownership of DPV assets will thus depend on whether particular ownership models emerge that can adequately manage such criticisms and on how policymakers weigh those considerations against potential benefits. In New York, for example, the Public Service Commission allows utility ownership of DER only under specified conditions: for projects that attract inadequate responses to competitive solicitations, projects involving storage connected to the distribution system, projects benefitting low-income communities, and demonstration projects (NYPSC 2015b). Other limited options, such as investments by unregulated subsidiaries outside the regulated utility service territory or utility ownership of inverters, may also offer relatively low-risk models.

Text Box 6. Recent Forays into Utility Ownership of Residential DPV

The most-discussed recent instances of utility ownership of residential DPV are the set of pilot programs administered by two Arizona IOUs, APS and Tucson Electric Power (TEP). In December 2014, the Arizona Corporation Commission (ACC) approved an 8–10 MW DPV program for APS and a 3.5-MW program for TEP (ACC 2014a, ACC 2014b). Under each of these programs, the administering utility would perform the majority of major functions in the DPV lifecycle—including customer acquisition, billing, operation and maintenance, and ownership—but would solicit installation contractors through an open request-for-proposal process. The systems will be interconnected on the utility side of the meter, and therefore the customer hosts will receive no NEM credits. Rather, in return for allowing the utilities to use their roof space, customers receive some other form of financial compensation: a rooftop lease payment of $30/month from APS or a long-term contract for a fixed bill from TEP.

The Arizona utilities noted several specific benefits from these programs in their filings to the ACC. These include reducing or eliminating investment in new distribution system infrastructure, extending the useful life of existing infrastructure, optimizing efficient dispatch of central station generation, piloting voltage control from advanced inverters, managing peak load on feeders by coupling with storage or facing the system westward, avoiding financial and legal complications associated with control of non-utility DPV systems, and reaching underserved customer who might not otherwise be able to access solar. (APS 2014; ACC 2014c). Both utilities stated that they would seek cost recovery in their upcoming rate cases, where their investments would be subject to prudency review.

In Texas, CPS Energy, the municipal utility serving San Antonio, recently launched a 10-MW pilot for ownership of residential rooftop systems. The program is similar to APS' pilot, whereby the utility will contract with a third-party installer to perform the installations, systems will be interconnected on the utility side of the meter, and customers will receive a monthly payment in exchange for use of their roof space (Trabish 2015b). Rather than a fixed monthly payment, however, CPS Energy will provide a payment based on the monthly production at a rate of $0.03/kWh.

In New York, Consolidated Edison has developed a solar offering through its unregulated affiliate, ConEdison Solutions, which will partner with SunPower to install DPV systems on customer rooftops throughout the state. Under the program, SunPower will supply the modules and offer panel warranties and production guarantees, while ConEdison Solutions will install, own, and maintain the rooftop systems (ConEdison Solutions 2015). Systems will be offered to homeowners via lease agreements of up to 20 years, closely resembling products available from third-party developers in the state (Trabish 2015a).

4.4 Shared Solar

Shared solar offers customers the opportunity to own, lease, or purchase the output from a portion of a PV system shared among multiple customers. Systems may be installed on shared roof space or on publicly owned or commercial buildings, or they may be ground mounted on vacant land. Shared solar can allow developers and participants to exploit sites with relatively high-quality solar resources, and it may offer opportunities for more optimized system design, greater economies of scale, and lower customer-acquisition costs compared with small rooftop installations. Because of some of these inherent economic advantages, interest and activity surrounding shared solar has recently blossomed, and the sector is projected to grow significantly in the coming years (Honeyman 2015).

Shared solar also offers opportunities to address stakeholder concerns surrounding NEM. Utility ownership or financing of shared solar projects could provide utility earnings opportunities that compensate for earnings lost owing to capital investments in traditional utility infrastructure that are deferred because of DPV. Community shared solar projects that offer broad participation for small customers may also offer several opportunities to address concerns associated with rate impacts and cost-shifting from DPV.

First and most obviously, community solar can expand DPV access to a much broader customer base. Estimates indicate that nearly 50% of households are unable to host their own system (Feldman et al. 2015). This includes customers who have shaded roofs, rent their homes or live in multi-tenant buildings, move frequently, have insufficient income or credit to purchase or lease a system, or simply do not have a suitable roof. Community solar programs with broad opportunities for participation may thereby help to dissipate some of the equity-related concerns associated with possible cost-shifting from NEM customers (without necessarily supplanting NEM). Community solar can target low-income communities through, for example, requirements to designate a minimum fraction of shares for low-income customers.[34]

Second, community solar may have lower revenue impacts to the utility than full retail NEM and therefore result in less cost-shifting to non-participants, if the bill credits to participating customers are based on a rate less than full volumetric retail electricity rates. From the perspective of the participating customer, receiving bill credits at a rate below retail prices might still be compelling, and could perhaps achieve returns on par with full NEM for rooftop DPV, given the lower levelized cost of electricity from community-scale projects. In this way, community solar might provide one solution to the zero-sum game that often accompanies any reforms to the way that solar customers are compensated.

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[34] Beyond community solar, a wide variety of other models has been used to expand access to solar energy. For example, a number of states have created programs that provide tailored upfront rebates for lower-income PV customers or low-interest loans to PV customers meeting income-eligibility criteria. Federal agencies have increasingly sought opportunities to support low-income solar, in many cases through existing programs for low-income housing, community development, and energy efficiency. Beyond explicit policy measures, private and non-profit solar market actors are increasingly targeting low- and middle-income customers through innovative business models, such as Grid Alternatives' Solar Affordable Homes Program and PosiGen's tailored model leveraging state tax incentives for low-income solar.

4.5 Performance-Based Regulation and Incentives

PBR is founded on the idea that utility behavior can be influenced when the utility is provided with appropriate financial incentives. PBR has developed as an alternative to the traditional model of COS regulation, in which electric rates are set periodically to allow utilities to recover their capital costs plus some reasonable return on their investments. Two major shortcomings of COS regulation are that utilities can increase profits by increasing sales volume, and the allowed levels of revenues are developed in relation to the level of capital investment, creating an incentive to increase capital expenditures (Comnes et al. 1995; RAP 2000).

The main objective of many early PBR programs, which arose in the 1990s in the context of broader electricity industry restructuring, was to minimize utility costs and eliminate the incentive created by COS regulation to increase capital expenditures. Revenue caps are one commonly used mechanism, and they function similarly to decoupling by allowing rates to be reset in between rate cases based on actual sales volumes. As such, revenue cap-based PBR can help to reduce utility disincentives toward activities that reduce sales growth, such as energy efficiency and net-metered DPV (Comnes et al. 1995).

Over time, the goals of PBR have gone beyond simply minimizing cost to a broader range of measures of utility performance. As such, the use of service-quality metrics—which historically were used in conjunction with PBR to ensure that cost reductions did not occur at the expense of service quality—has shifted from a minimum standard to a baseline against which utility performance can be gauged and appropriately incentivized. Incentives may take the form of dollars, upward or downward adjustment to the allowed rate of return, or an increase or decrease in the allowed base revenues to be collected (Mandel 2015).

Traditional areas tracked and incentivized through PBR include reliability, power plant performance, and customer satisfaction, while new PBR programs look to encourage broader societal outcomes such as customer engagement in energy efficiency and minimization of environmental impacts, as shown in Figure 20 (Woolf et al. 2014). One of the most widely profiled PBR systems is the United Kingdom's Revenue = Incentives + Innovation + Outputs, or RIIO, model, which encompasses a relatively wide range of performance metrics (see Text Box 7). Synapse Energy Economics recently developed a handbook for regulators on the design, implementation, and tracking of utility performance-incentive mechanisms, in which they discuss key considerations such as the degree to which aspects of performance are verifiable and the structure of penalties and awards (Whited et al. 2015).

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Traditional Performance Areas	Emerging Performance Areas
Reliability	Overall system efficiency
Safety	Customer engagement
Customer Satisfaction	Network support services
Power Plant Performance	Environmental goals
Costs	
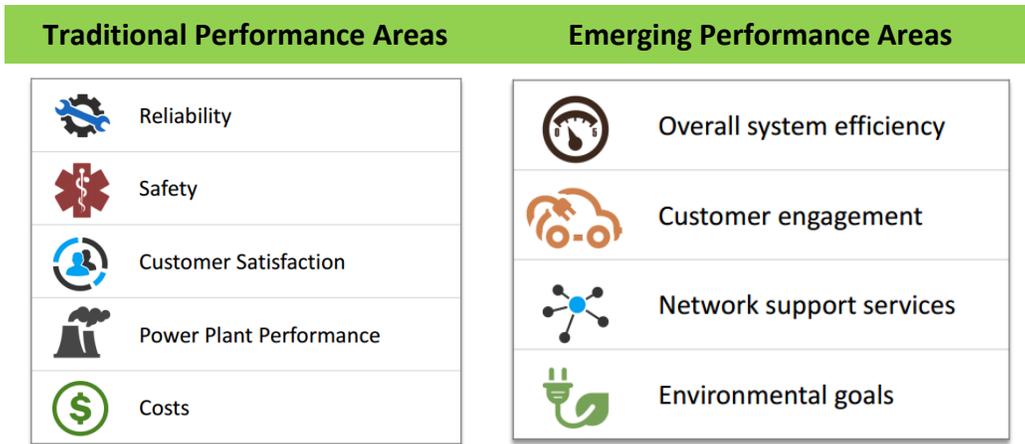
Figure 20. Utility performance areas for PBR

Source: Woolf et al. 2014

Distinct from, but related to, PBR are targeted utility incentives that can reward the utility for specific measures of performance. These have been used widely to encourage utility performance in administration of energy efficiency programs, and they come in various forms, including shared net benefits, capitalization of program costs (potentially with a bonus level of returns), and incentives for meeting specified performance targets (Cappers and Goldman 2009).[35] Similar kinds of performance incentives could be extended to other forms of DER as well, potentially including DPV. The New York Public Service Commission, for example, recently authorized ConEdison to receive up to a 100 basis-point bonus on customer-sited DER costs, as part of the utility's Brooklyn/Queens demand-management program aimed at deferring traditional distribution system upgrades (NYPSC 2014). The bonuses are tied to targets related to the level of peak demand savings achieved, cost savings relative to traditional T&D investments, and the diversity of DER providers.

Performance-incentive mechanisms, whether as standalone incentives or integrated into a broader PBR scheme, can have important implications for the deployment of solar energy. In particular, they help to sever the linkage between traditional utility capital expenditures and profits, thus mitigating the erosion of utility shareholder earnings that might otherwise occur if DPV leads to the deferral or avoidance of utility capital expenses. Depending on how they are designed, performance-incentive mechanisms could be used to create positive earnings and profit opportunities associated with DPV, by establishing performance metrics linked specifically to facilitating the growth of those resources.

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[35] As of July 2013, 28 states had approved a shareholder incentive mechanism for at least one utility: eight states with incentives based on a percentage of energy efficiency program costs, 13 states with incentives based on shared net benefits, four states with incentives based on a percentage of avoided costs, and three states with incentive mechanisms approved but specifics yet to be determined (IEE 2013).

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Text Box 7. The United Kingdom's RIIO Model

The United Kingdom has implemented a new regulatory approach for DSOs known as RIIO, which succeeded its previous RPI-X price cap regulation. Short for "Revenue = Incentives + Innovation + Outputs," RIIO is a PBR model using revenue caps that emphasizes public consultations and stakeholder engagement. RIIO is a comprehensive PBR regime that tracks utility performance in six key output categories—customer satisfaction, reliability and availability, safe network service, connection terms, environmental impact, and social obligations (Fox-Penner et al. 2013)—though DSO earnings are still overwhelmingly driven by the allowed rate of return on investment.

Under RIIO, each electric distribution company develops a business plan for negotiation and approval by the regulator (Ofgem), detailing how they will achieve the target levels of performance in each of the specified output categories (Lehr 2013). The plan serves as a regulatory contract and contains "outputs and deliverables" that detail how performance of the distribution company will be assessed by Ofgem. The distribution companies then implement these plans over the following 8-year period; this is a remarkably long regulatory cycle relative to other schemes, but it allows utilities to make and execute long-term plans, and it allows a longer period for utilities to profit from operational efficiencies achieved (Lehr 2013). The long regulatory cycle is considered to be one of the differentiating features of the RIIO model. Others include the selection of tracked output categories through stakeholder engagement (rather than regulator fiat); the practice of funding awards for outperforming utilities from the penalties collected from underperformers; and funding pools from research and development, pilot, and other innovative projects (Aggarwal and Burgess 2014).

4.6 Broader Business Model and Market Reforms

Various other, even more far-reaching reforms to utility business models and electricity markets have been articulated in the literature and within the context of specific state regulatory proceedings. Although these concepts are still largely theoretical, they might conceivably address some current concerns related to the financial impacts of DPV on utility shareholders or ratepayers by realigning utility profit incentives to be compatible with DPV growth, stimulating higher-value DPV deployment that alleviates cost-shifting across customer classes, or both.

4.6.1 Distribution Network Operator

The incumbent utility, either vertically integrated or distribution only, has traditionally been responsible for the maintenance and operation of the distribution network, but some electric utility regulatory and business models propose new or expanded roles for the network operator. Fox-Penner (2010) describes a utility business model that defines the utility distribution company as the "Smart Integrator" of upstream and downstream supply resources, storage devices, and other grid assets to ensure reliable service. The Smart Integrator would focus primarily on reliable operation of the system, rather than on commodity energy sales, and might directly control or interact with some customer-owned energy systems, including DPV. Others have suggested a more diminished role for utilities, with many distribution coordination functions vesting among competitive DER providers (Corneli and Kihm 2015).

One recent and specific proposal for a distribution service provider (DSP) or distribution service platform provider (DSPP) has emerged within New York's REV proceeding. The DSP would be tasked with enabling efficient dispatch of distributed and centralized energy resources on an equal basis, potentially creating an opportunity for lower-cost methods of meeting load than

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under current models. The REV proceeding stipulates that, for the time being, the DSP role would be filled by the incumbent distribution utilities, recognizing that many DSP functions and necessary systems correspond to their existing capabilities and assets (Cross-Call and Hansen 2014). However, the utilities are expected to fulfill a more neutral role in integrated system planning, grid operations, and market operations. For example, to enable participation of DERs in meeting loads, utilities will develop standardized markets and tariffs for the distribution system (Aggarwal and Gimon 2014).

Whereas the New York REV proceeding envisions a role for the incumbent distribution utility, the Independent Distribution System Operator (IDSO) model proposes to instead adapt the bulk power system model of a regional transmission organization (RTO) or independent system operator (ISO) to the distribution system. Under an IDSO model, the regulated distribution utility would continue to build, own, and maintain the distribution system infrastructure, but it would turn over the planning, procurement, and operational control of distribution assets to the IDSO, much as participating transmission owners do in an RTO or ISO (Wellinghoff et al. 2015).

Reforms to the ownership, management, and operation of the distribution network have implications for utility shareholders and ratepayers, though the direction and magnitude of impacts depend on the specifics of the reforms. Utility shareholders may perceive a change in risk as the utility is asked to take on new roles and responsibilities to more explicitly integrate distributed resources and third-party energy services. Utilities may need to develop new markets and tariffs to allow for open network access, which may, in turn, enable new revenue streams. Ratepayers may also see overall cost savings from more efficient distribution grid operation and increased reliability from the integration of distributed resources, though reforms may increase costs to ratepayers in instances where multiple entities take on distribution network operator roles and some functions overlap.

The distribution network operator would enable greater interaction and control of DPV resources, and new distribution markets and tariffs could provide the revenues necessary for DER providers to generate profit and create viable business models. Regulators would likely continue to review and approve market designs and tariffs to ensure no single entity has preferential network access.

4.6.2 Services-Driven Utility

Utilities have traditionally offered only an electric commodity service to customers, but some regulatory and business model reforms are expanding utility service offerings, especially toward downstream energy services beyond the meter-base. A services-driven utility plays an increased role in delivering value-added services, with profit achievement based more on services provided than on commodity sales (Satchwell et al. 2015). This is similar to the Energy Services Utility (ESU) model articulated by Fox-Penner (2010), where the utility is encouraged to deliver all manner of energy-related "products" to customers via distinct pricing schemes. For example, the ESU might offset revenue losses from DPV or energy efficiency by actively selling energy audits and weatherization services to customers. The ESU could develop offerings with varying levels of service and corresponding price differentiation (Lehr 2013). Other aspects of the ESU—such as delivery of energy, responsibility for reliable operation of the grid, and dynamic pricing—are shared in common with the distribution network operator models. Importantly, both business models could still be governed either by traditional COS regulation or by PBR, though the ESU

would require considerably more regulatory effort, because it would encompass far more functions than is typical of today's electric utilities (Fox-Penner 2010). Additionally, regulators would need to define clearly the role of the utility in offering services and any potential negative impacts on competitive markets, to the degree the markets exist or could exist.

One small step toward the ESU model could be exemplified by a recent Georgia Power program, through which the utility offers solar consultation services to its customers to assess whether their homes are well suited to solar (Georgia Power 2015). If customers wish to pursue solar, the utility representative will connect them with a number of local solar installers, including Georgia Power Energy Services, the parent company's unregulated project development arm (Pyper and Wesoff 2015). As of this writing, neither Georgia Power nor Georgia Power Energy Services offer financing for solar loans or leases, nor will they own the rooftop solar asset. Instead, installed systems are simply offered for purchase by the customer, who is responsible for arranging financing independently if needed.

Shifting utility profit achievement toward services provision addresses some of the current utility disincentives toward DERs by offsetting revenue erosion from lost commodity sales with new revenue streams. The most significant change under a services-driven utility model is pricing specific energy services, which has implications for utility shareholders and ratepayers. To the extent utilities directly compete with third-party service providers, utilities would also face additional business risks. While increased competition for services may lower prices, the increased choices may pose additional risks for customers. DPV customers may face new risks from needing to manage electricity consumption in different ways, including choosing between utility and third-party providers for desired services. Additionally, paying separately for energy services may change customer decision making and customer-economics impacting the adoption of DPV (Satchwell et al. 2015).

4.6.3 Transactive Energy

Transactive energy is a recent concept that denotes a vision of future electrical grid operations based on pricing and the assignment of value at every level of the grid. The GridWise Architecture Council, which has spearheaded work in this space, defines transactive energy as "a system of economic and control mechanisms that allows the dynamic balance of supply and demand across the entire electrical infrastructure using value as a key operational parameter" (GridWise Architecture Council 2015). This paradigm calls for open and transparent pricing of energy services and non-discriminatory grid access for supply- and demand-side energy resources to both the bulk power and retail power systems. The goal of such a system would be to integrate all available resources within a given geographic footprint to meet load at least cost (Atamturk and Zafar 2014). This proposal borrows some elements from the operations of RTOs/ISOs—such as differentiation of pricing based on value, similar to locational marginal pricing—and the opportunity for entities to engage in spot energy markets or manage price risk by accepting longer-term forward contracts (Atamturk and Zafar 2014).

The transactive energy concept does not express a preference for the type of entity responsible for managing the energy market and leaves open the possibility that—with sufficient standardization, automation, and regulation—a managing entity for the electricity system may be altogether unnecessary. The major difference between transactive energy and the DSP and IDSO concepts is the level of integration between bulk and retail power systems. In transactive energy,

this division is erased, with distributed and centralized resources competing on a level basis. In DSP and IDSO models, new entities are tasked with operational control of the distribution system, but they must coordinate the balancing of supply and demand with the existing ISO or transmission operator.

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5 Conclusions: Toward a Framework for Addressing Stakeholder Concerns about DPV

NEM with volumetric retail electricity pricing has been instrumental to the U.S. DPV market. With this success, however, have come concerns about possible financial consequences for utilities and their customers, including increased retail electricity rates and cost-shifting to non-solar customers, reduced utility shareholder profitability, and reduced utility earnings opportunities. Regulators and others may also have related concerns about whether current DPV compensation results in efficient allocation of resources, particularly in the context of achieving environmental or other policy goals. To varying degrees, the significance of these concerns may depend on the timeframe of analysis and on the magnitude of utility cost savings from DPV. In most utility service territories, however, current DPV deployment is still far too low for these impacts to be significant. Nevertheless, for a variety of reasons, many utilities, regulators, and other stakeholders are seeking to preempt more-acute issues in the future.

As discussed throughout this report, various reforms to utility regulatory and business models have been discussed, proposed, and in some cases implemented to address the aforementioned set of concerns. At a broad conceptual level, each of these reforms exemplifies one or more of four basic strategies for mitigating stakeholder concerns about DPV, and each of those strategies, in turn, targets one or more of the specific stakeholder concerns noted above (Table 3).

Table 3. Strategies to Address Concerns about the Utility Financial Impacts of DPV

Strategies	Stakeholder Concerns Addressed		
	Increased Retail Electricity Rates and Cost-Shifting	Reduced Utility Shareholder ROE	Reduced Utility Earnings Opportunities
Reduce compensation to DPV customers Key examples: NEM and retail rate reforms, community solar	✔	✔	✔
Facilitate higher-value DPV deployment Key examples: time-varying, locational, or unbundled attribute pricing; enhanced utility system planning, utility ownership and financing of DPV, shared solar, distribution network operators, ESUs	✔	✔	
Broaden customer access to solar Key examples: utility ownership and financing of DPV, community solar	✔		
Align utility profits and earnings with DPV Key examples: Decoupling and other ratemaking reforms to reduce regulatory lag, utility ownership and financing of DPV, performance-based incentives, distribution network operators, ESUs		✔	✔

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Understanding how specific reforms map onto this set of more general strategies can help to identify and prioritize options for addressing specific concerns about DPV that balance the various stakeholder interests:

- **Reduce compensation provided to DPV customers:** Reducing the bill savings or other forms of compensation provided to DPV customers directly reduces the resulting revenue erosion and any associated cost-shifting or decline of utility profitability (putting aside the basic empirical question of whether, and to what extent, DPV with NEM actually shifts costs over the long run). By dampening further DPV deployment, reductions in compensation to DPV customers also indirectly reduce any lost earnings opportunities by the utility from displaced traditional utility capital investments. Naturally, this strategy generally represents a zero-sum game, in the sense that it solves problems from the utility perspective only to the extent that it reduces the economic returns to DPV customers.

  Current efforts to reform NEM rules and retail rate designs for DPV customers generally exemplify this strategy and, as discussed in Section 3, could lead to substantial restrictions on future DPV growth. Customer-sited storage and demand flexibility may provide DPV customers with some ability to insulate themselves from changes to NEM and rate design—but in doing so, might partially undermine the attempt to stem utility revenue erosion. Community shared solar may also provide a means to reduce compensation for PV customers, if participant bill credits are priced below retail rates. However, participants might still be able to achieve economic parity compared to rooftop DPV with traditional NEM, given the lower underlying costs of community solar projects. In this way, community solar—if pursued as an alternative to rooftop DPV and if participation is widely available—might be an exception to the zero-sum rule by allowing for reduced compensation to solar customers without markedly altering customer-economics and market growth.

- **Facilitate higher-value forms of DPV deployment:** Any cost-shifting to non-solar customers or erosion of utility shareholder ROE associated with DPV is a function of the relative size of DPV's impacts on revenue growth and cost growth. Reducing the bill savings received by DPV customers addresses one half of that equation; increasing the value received by utility shareholders and ratepayers—in the form of cost savings or improved quality of service—addresses the other half. The key difference between the two, from the perspective of the DPV market, is that increasing DPV's value need not undermine its customer-economics or constrain its growth. That said, utilities and ratepayers may not view the two as equivalent, given the longer-term and less-readily observable nature of many system benefits from DPV (compared to the revenue impacts, which are immediate and unambiguously quantifiable). Moreover, for utility shareholders, higher-value DPV deployment may occur through greater deferral of traditional utility infrastructure, potentially exacerbating lost earnings opportunities.

  Many of the reforms discussed in this report could facilitate higher-value forms of DPV deployment. Certain retail rate reforms—such as time-varying, locational, and unbundled attribute pricing—could help incentivize more optimally sited and grid-friendly DPV, though those innovations are generally not without associated cost to the DPV customer. Such rate reforms may also require effort to establish the value of DPV production as well as greater tolerance for differentiation among customers in a given utility. Enhanced

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utility system planning can provide an analytical foundation for these pricing designs and for other mechanisms to preferentially direct DPV deployment toward particular locations or particular design characteristics that increase its value to the utility system. Utility ownership of DPV assets, whether DPV systems as a whole or only inverters, might provide one other way to enhance the value of deployed DPV through optimized siting and operation. Community solar, and shared solar more generally, might also facilitate optimized siting and design, and it may more readily allow for deferral of distribution system upgrades, given its larger size and the ability to place that capacity strategically on specific circuits. Finally, over the longer term, many of the more far-reaching potential reforms to utility business models and retail markets (e.g., transformation of today's electric utilities into ESUs, formation of distribution network operators, and formation of transactive retail electricity markets) could also facilitate higher-value DPV deployment through more finely targeted price signals or procurement processes.

- **Broaden customer access to solar:** Efforts to target low- or middle-income customers, those with credit scores too low to qualify for TPO, or other underserved markets can help to diffuse concerns about cost-shifting and potentially regressive effects of NEM. To be sure, such a strategy does not fundamentally address any underlying cost-shift associated with NEM; indeed, simply facilitating greater overall levels of NEM participation might exacerbate those cost-shifts (not to mention erosion of utility shareholder profits and earnings). Nevertheless, concerns about the impacts of DPV on non-solar customers are, in the end, often driven more by perceptions of fairness than by the mere existence or magnitude of a cost-shift. After all, cost-shifting and cross-subsidies have always been pervasive in retail rate designs, and those associated with DPV are, in the vast majority of cases, likely far smaller than many other sources of cost-shifting. One reason why energy efficiency programs are less susceptible to such concerns is that opportunities for participation are broad and often supported by programs targeted to low-income or other hard-to-reach customer segments.

  Among the reforms highlighted in this report, community shared solar offers perhaps the most explicit pathway toward expanding customer access, particularly for renters and customers without suitable roof space, though community solar offerings might also target low-income customers through set-asides or discounts. Utility ownership of DPV may also provide a mechanism for expanding access to underserved customer segments, as several recent utility proposals have sought to do, and in doing so may avert some of the objections with utilities competing directly against unregulated companies.

- **Align utility profits and earnings with DPV growth:** Under traditional COS regulation, utilities' profits are based on capital investments, and their financial performance is contingent on their ability to exploit regulatory lag by growing electricity sales between rate cases at a faster pace than costs. Naturally then, DPV and other activities that reduce sales growth and the need for traditional utility capital investments will tend to erode utility financial performance and thus create a disincentive for those kinds of activities. Regulatory and business model reforms can seek to realign utility financial incentives so they are at least neutral toward, if not positively affected by, DPV growth. In general, such reforms focus on addressing utility shareholder concerns about DPV, but they do not directly address (and may even exacerbate) ratepayer concerns related to cost-shifting.

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A wide range of specific reforms has been suggested to realign utility financial incentives with the growth of DPV. Some reforms entail relatively "incremental" changes to current utility regulatory and business models. These include decoupling and other ratemaking reforms to reduce regulatory lag, which already have widespread adoption and serve to hold utility profits immune to DPV growth, though they do not directly address lost earnings opportunities resulting from the deferral of traditional utility capital investments. Performance-based incentives and utility ownership or financing of DPV assets both offer the potential to create positive utility earnings opportunities associated with DPV growth, and they have some precedents, but they represent an incrementally greater departure from the traditional COS utility model. Finally, many of the new conceptual utility business models to recently emerge within the literature and state regulatory proceedings (e.g., ESUs, distribution network operators) are intended specifically to realign utility financial incentives vis-à-vis DPV, often by reorienting utility profits around the provision of services rather than commodity sales of electricity (Satchwell et al. 2015). Some of these conceptual models might also incorporate utility ownership of DPV assets and performance-based incentives.

In summary, efforts to address concerns by utilities and non-solar customers about the financial impacts of DPV growth are unfolding across the country in a variety of forms. To date, most efforts to address stakeholder concerns about DPV growth have centered on reforms to NEM rules and retail rate designs. This pathway has certain practical advantages because these kinds of reforms address concerns of both utility ratepayers and shareholders and can often be implemented in a relatively immediate fashion, without requiring wholesale remaking of utility business models and regulatory processes. As noted above, though, these reforms are generally premised on reducing compensation provided to DPV customers and, as such, achieve their objectives only insofar as they constrict DPV customer-economics.

The many alternative reforms discussed in this report provide opportunities to address utility and/or ratepayer concerns about DPV without necessarily constraining DPV growth—by instead facilitating higher-value DPV deployment, expanding customer access, and aligning utility earnings and profits with DPV growth. Some of these reforms—such as decoupling, shared solar, utility ownership and financing of DPV assets, and enhanced utility system planning—have already been adopted and are options for wider implementation within the timeframe of the SunShot 2020 goals. Other, more fundamental business model reforms will unfold over a longer time horizon and have a more uncertain outcome; activities within the near term will consist primarily of iterative steps in the development, testing, and refinement of concepts. In either case, opportunities exist to preserve the long-term legacy of the SunShot Initiative by promoting a stable regulatory environment and utility business models that align DPV adoption with the continued provision of safe, reliable, and affordable electricity service.

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