Regulatory and Ratemaking Approaches to Mitigate Financial Impacts of Net-Metered PV on Utilities and Ratepayers

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Abstract

The financial interests of U.S. utilities are poorly aligned with customer-sited solar photovoltaics (PV) under traditional regulation. Customer-sited PV, especially under a net-metering arrangement, may result in revenue erosion and lost earnings opportunities for utility shareholders as well as increases in average retail rates for utility ratepayers. Regulators are considering alternative regulatory and ratemaking approaches to mitigate these financial impacts. We performed a scoping analysis using a financial model to quantify the efficacy of mitigation approaches in reducing financial impacts of customer-sited PV on utility shareholders and ratepayers. We find that impacts can be mitigated through various incremental changes to utility regulatory and business models, though the efficacy varies considerably depending on design and particular utility circumstances. Based on this analysis, we discuss tradeoffs policymakers should consider, which ultimately might need to be resolved within broader policy contexts.

Keywords: Customer-sited PV; Utility Regulation; Decoupling; Shareholder Incentives; Rate design

1. Introduction¹

Regulators and policymakers are increasingly concerned about the negative financial impacts of customer-sited solar photovoltaics (PV) on utilities and ratepayers as PV deployments rapidly accelerate. Utilities point to impacts on profitability, as declining retail sales reduce collected revenues and future earnings opportunities. At the same time, average retail rates may increase because the utility must spread its fixed costs over a smaller sales base.

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¹ *Abbreviations:* EE – energy efficiency; GRC – general rate case; ITC – investment tax credit; LRAM – lost revenue adjustment mechanism; NE – Northeast; NEM – net energy metering; NPV – net present value; PPA – power-purchase agreement; PV – solar photovoltaic; REC – renewable energy credit; ROE – return on equity; RPC – revenue per customer; RPS – Renewables Portfolio Standard; SW – Southwest.

Debates about net metering are taking place against the backdrop of a larger set of discussions about existing utility business and regulatory models. One dimension of those broader discussions has focused on the poor alignment between the traditional utility business model – whereby utility profits are closely tied to sales volume and capital investments – and recent advances in technology and public policy that are driving the growth of demand-side resources, which tend to reduce sales and opportunities for capital investments (Kind 2013, Fox-Penner 2010). Arguably the greatest progress on those issues has occurred with respect to utility ratepayer-funded energy-efficiency (EE) programs, where the unintended consequences of the “utility throughput incentive” to increase sales and add capital investments to the utility’s ratebase long have been recognized and a variety of regulatory tools have been developed and deployed to better align utility financial interests with EE goals (Wiel 1989, Moskovitz et al. 1992, Harrington et al. 1994, Stoft et al. 1995, Eto et al. 1997, Kushler et al. 2006, NAEPP 2007). Among the goals of the present study is to leverage this base of experience and illustrate how some of the same regulatory and ratemaking strategies could also be applied in the context of distributed PV.

A number of the EE studies and several others (Bird et al. 2013, Blackburn et al. 2014, Linvill et al. 2013, Kihm and Kramer 2014, Shirley and Taylor 2009) identify regulatory and ratemaking options for mitigating adverse rate impacts from distributed PV, while many others also discuss possible broader changes to utility business and regulatory models that are compatible with, or that could facilitate the growth of, distributed PV (EPRI 2014, Hanelt 2013, Harvey and Aggarwal 2013, Lehr 2013, Moskovitz 2000, Newcomb et al. 2013, Nimmons and Taylor 2008, Richter 2013a, Richter 2013b, Rickerson et al. 2014, RMI 2012, RMI 2013, Wiedman and Beach 2013). The studies provide a qualitative discussion of incremental and more

fundamental changes to utility business and regulatory models, but they do not attempt to model and quantify the efficacy of those changes to better align shareholder and ratepayer interests with distributed PV.

Using a pro-forma financial model, we quantify the impact of a number of possible mitigation approaches that might reduce any negative impacts to shareholders and/or ratepayers from growing amounts of customer-sited PV under a net-metering arrangement.^{2,3} These mitigation measures include alternative rate designs, utility revenue decoupling, utility ownership of distributed PV, and various other strategies. Our analysis results are based on characterizations of two prototypical utilities in the U.S.: a vertically integrated utility in the Southwest (“SW Utility”) and a wires-only utility and default service supplier in the Northeast (“NE Utility”). Both utilities collect revenues through a fixed customer charge (\$/customer), volumetric demand charges (\$/kW), and volumetric energy charges (\$/kWh). As described in more detail later, the rate of growth of customers and sales is higher for the SW Utility than for the NE Utility, though the fixed costs of the NE Utility grow at a higher rate. Since the SW Utility is vertically integrated, a much larger share of its costs are related to capital investments (45% of costs) compared with the NE Utility (16%).

Importantly, the paper builds on a companion article quantifying the impacts of customer-sited PV on the same prototypical utilities (see Satchwell et al. 2015). For each utility, we modeled the potential impacts of PV over a 20-year period, estimating changes to utility costs, revenues, average rates, and utility shareholder earnings and return-on-equity (ROE). The utility

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² The work in this article is based on a longer technical report (Satchwell et al. 2014), entitled *Financial Impacts of Net-Metered PV on Utilities and Ratepayers: A Scoping Study of Two Prototypical U.S. Utilities*, available at: emp.lbl.gov/publications.

³ Net energy metering (NEM or simply “net metering”) is a billing mechanism that allows customers to export electricity generated by their PV systems to the grid and apply that excess generation against electricity consumption at other times, in effect receiving credit for all PV generation at the prevailing retail electric rate. It is currently the predominant compensation mechanism for customer-sited PV in the U.S.

shareholder and ratepayer impacts of customer-sited PV were first assessed under a set of base-case assumptions related to each utility's regulatory and operating environment, in order to establish a reference point against which potential mitigation strategies could be measured. The base-case analyses were performed with total penetration of customer-sited PV rising over time to stipulated levels ranging from 2.5% to 10% of total retail sales (compared to current penetration levels of 0.2% for the U.S. as a whole and of roughly 2% for utilities with the highest penetrations, excluding Hawaii), all under a net-metering arrangement.⁴ Each of these PV penetration cases was compared to a scenario with no customer-sited PV over the entire analysis period.

Results from the companion article identify two negative financial impacts for the modeled utilities and one negative impact for ratepayers. First, although customer-sited PV reduces total utility costs by roughly similar amounts for the two prototypical utilities,⁵ the reduction in non-fuel revenues generally outpaces the reduction in non-fuel costs, which reduces the utility's ROE and results in the "revenue erosion effect." Second, some reductions in non-fuel utility costs represent deferred or avoided future utility capital investments in generation plants, transmission systems, and distribution systems. This diminishes future earnings opportunities, resulting in the "lost earnings opportunities effect." From the ratepayer perspective, reduced utility retail sales due to customer-sited PV increase average all-in retail rates (expressed as total annual collected revenue divided by total annual retail sales) as costs are spread over a smaller sales base. The mitigation approaches in this paper are targeted at the two impacts on utilities and the one impact on ratepayers identified in the foundational study.

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⁴ Specifically, penetration of customer-sited PV rises from zero in year 1 to levels ranging from 2.5% to 10% of retail sales in year 10 and then remains constant as a percentage of retail sales for the latter 10 years of the 20-year analysis period. This approach was taken in order to capture end-effects that occur after PV additions take place.

⁵ SW Utility costs decrease 1.3% and NE Utility costs decrease 1.5% under 2.5% PV penetration, and SW Utility costs decrease 4.0% and NE Utility costs decrease 4.5% under 10% PV penetration.

2. Methods

We used a pro-forma financial model that calculates utility costs and revenues based on specified assumptions about the utility's physical, financial, operating, and regulatory characteristics.⁶ This model has been used to analyze the financial impacts of EE programs on utility shareholders and ratepayers under alternative utility business models (Cappers and Goldman 2009a, Cappers and Goldman 2009b, Cappers et al. 2010, Satchwell et al. 2011) and to analyze the impacts of customer-sited PV (Satchwell et al. 2014, Satchwell et al. 2015).⁷

Aside from the traditional cost-of-service business model, alternative regulatory mechanisms can be implemented in the model. The model can represent sales-based or revenue-per-customer (RPC) decoupling mechanisms, lost-revenue-adjustment mechanisms, and shareholder-incentive mechanisms. It can also analyze alternative ratemaking approaches (e.g., a high fixed customer charge) by changing the way utility revenues are collected among different billing determinants.

Table 1 shows the mitigation cases examined in this analysis. Though by no means exhaustive, this set of measures includes many of the regulatory and ratemaking strategies implemented or discussed in connection with EE programs as well as analogues that might apply to PV. Most of these measures specifically target the shareholder impacts from customer-sited PV (associated with either revenue erosion or lost earnings opportunities), and these measures might exacerbate the ratepayer impacts from customer-sited PV, exemplifying one kind of tradeoff that can arise.

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⁶ Data to populate the model for this analysis were taken from publicly available utility filings, including integrated-resource plans, rate-case filings, and shareholder financial information (e.g., SEC 10-k).

⁷ The model was adapted from a tool (the Benefits Calculator) initially constructed for the National Action Plan on Energy Efficiency (NAPEE) to analyze the financial impacts of EE programs on utility shareholders and ratepayers under alternative utility business models (NAPEE 2007). We significantly updated and expanded the Benefits Calculator for the present study.

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7 Our analysis of mitigation measures focuses on the 10% PV penetration scenario so that
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9 the effects of the measures are revealed clearly. Assuming lower PV penetration for this portion
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11 of the analysis produces qualitatively similar, but less discernible, results. The mitigation
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13 analysis involves changes from base-case conditions that occur only in conjunction with PV.
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15 Thus we gauge the effectiveness of each mitigation measure in terms of the extent to which it
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17 restores shareholder earnings, shareholder ROE, and/or average rates to the levels that occur
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19 without PV under the base-case utility conditions.
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24 Finally, in discussing the results of this analysis, we highlight how many of the mitigation
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26 measures considered may have divergent consequences for shareholders and ratepayers or may
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28 entail tradeoffs with other policy or social objectives. For example, increasing fixed customer
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30 charges may dampen the long-run price signal for energy conservation.
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36 **3. Results**

37 38 *3.1 Decoupling and LRAMs can moderate ROE impacts, though effectiveness depends critically* 39 40 *on design and utility characteristics* 41 42

43 The traditional electric utility business model in the United States provides a financial
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45 incentive for the utility to increase electricity sales between rate cases, commonly referred to as
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47 the “throughput incentive” (Eto et al. 1997, RAP 2011). A bias among utilities, therefore, exists
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49 against resources or policies, like EE or customer-sited PV, that decrease sales. Several
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51 regulatory tools have been used in the context of EE to mitigate this disincentive, including
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53 various forms of revenue decoupling as well as lost revenue adjustment mechanisms (LRAMs).
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57 Our mitigation cases explore the applicability of these measures to customer-sited PV.
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Revenue decoupling is designed to mitigate disincentives for EE and other demand-side resources by “decoupling” utility revenues from sales.⁸ RPC decoupling allows revenues to grow based on the growth in the number of customers between rate cases, rather than on growth in retail sales.⁹ Another design element of decoupling is the application of a revenue-growth factor, commonly called a “k-factor.” The k-factor allows the revenue (or RPC) established in a general rate case (GRC) to grow between rate cases to better match growth in fixed costs between rate cases. This is particularly important for a utility facing the effects of high cost inflation and high fixed cost (e.g., labor costs, pension costs) growth.

An LRAM, like decoupling, is also intended to address the “throughput incentive,” though it does so by reimbursing the utility specifically for lost revenues directly attributable to EE programs. Thus, unlike revenue decoupling, which fully severs the tie between sales and revenues, an LRAM is more narrowly focused on sales reductions associated with EE programs (or, in our analysis, customer-sited PV).¹⁰ In practice, implementation of an LRAM can be contentious, because it requires estimation of the amount of energy saved as a result of the EE measure (Carter 2001). In this respect, LRAMs may be easier to implement for customer-sited PV than for EE, because PV production can be directly metered, whereas the change in sales due to EE is more speculative.

To illustrate the potential applicability of these measures to customer-sited PV, we developed mitigation scenarios involving two variants of RPC decoupling – one with a k-factor and one without a k-factor – and one scenario with an LRAM. For the mitigation case involving

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⁸ Critics of decoupling contend that it removes the utility’s incentive to manage its costs between GRCs, among other things.

⁹ As of July 2013, 14 states had approved revenue-decoupling mechanisms for at least one utility (IEE 2013). See RAP (2011) for a description of the different forms of decoupling. We model RPC decoupling because it is the most common.

¹⁰ As of July 2013, 18 states had approved LRAMs for at least one utility (IEE 2013).

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4 RPC decoupling without a k-factor, growth in collected revenues is set equal to growth in the
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6 number of customers between rate cases. For the mitigation case involving RPC decoupling with
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8 a k-factor, the k-factor is set at the value necessary to restore ROE to the level achieved in the
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10 base case without PV. Under the LRAM mitigation case, the utility collects – on an annual basis
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12 between rate cases – additional revenue equivalent to the product of the energy produced by PV
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14 and the non-fuel volumetric energy rate.
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19 We assess the impact of these mitigation measures on achieved ROE and average retail
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21 rates by comparing the scenarios with 10% PV and the mitigation measure to scenarios with 10%
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23 PV and no mitigation measure (see Figure 1). As a point of reference, this figure and others
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25 throughout the remainder of this section also show the change in each metric between 0% and
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27 10% PV under base-case conditions (i.e., with no mitigation measure) in order to illustrate the
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29 extent to which each mitigation measure either offsets or exacerbates the effect of PV. We focus
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31 our assessment of the effectiveness of RPC decoupling and LRAM on the change in achieved
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33 average ROE, though the earnings impacts are qualitatively similar.
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38 As shown in Figure 1, the various mitigation measures generally improve utility ROE
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40 relative to cases with 10% PV and no mitigation measure, though the effect varies greatly
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42 depending on the utility, the type of measure, and its design. With respect to decoupling,
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44 implementing RPC decoupling *without* a k-factor leads to a 108 basis-point increase in achieved
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46 ROE for the SW Utility, resulting in an average ROE exceeding the level achieved without PV.
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48 This significant ROE improvement is due to the fact that growth in the number of customers is
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50 substantially higher than growth in non-fuel revenues in the base case with 10% PV;¹¹ thus the
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57 ¹¹ Non-fuel revenues are the point of comparison because we assume the utility collects fuel revenues on an
58 annual basis through a fuel adjustment charge (FAC), which perfectly matches fuel revenues with fuel and
59 purchased-power costs. Growth in non-fuel revenues is a function of growth in billing determinants (retail sales,
60 peak demand, and number of customers).
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4 utility collects substantially greater revenues when those revenues are tied more closely to
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6 growth in the number of customers, as occurs with RPC decoupling. Conversely, customer
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8 growth is low for the NE Utility relative to growth in non-fuel revenues, thus RPC decoupling
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10 without a k-factor actually exacerbates ROE erosion. For both utilities, RPC decoupling with a k-
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12 factor restores ROE back to the level achieved without PV, under base-case conditions. This
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14 outcome is by design, based on choice of the k-factor; our analysis requires a negative k-factor
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16 for the SW Utility and a positive k-factor for the NE Utility.
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21 We see an improvement in average ROE when we implement an LRAM in the case with
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23 10% PV. An LRAM is designed to mitigate only the revenues lost owing to the customer-sited
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25 PV savings (as opposed to the RPC decoupling mechanism that is designed to mitigate *all* lost
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27 revenues). To calculate the additional revenues to the utility from the LRAM, we multiplied the
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29 energy savings from customer-sited PV by the non-fuel volumetric energy rate. In the SW Utility
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31 the LRAM virtually achieves ROE comparability, but in the NE Utility an LRAM is not enough
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33 to achieve ROE comparability. This is due primarily to the fact that the LRAM, as implemented
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35 in our analysis, only compensates the utility for lost non-fuel *energy* revenues and does not
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37 include utility revenues collected via a *demand* charge, which are also reduced by customer-sited
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39 PV. The NE Utility collects a larger proportion of non-fuel revenues from a demand charge than
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41 the SW Utility, and the LRAM, therefore, only compensates the NE Utility for a small proportion
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43 of lost revenues.
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50 To the extent that decoupling and LRAMs mitigate the ROE impacts from customer-sited
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52 PV, they do so by increasing revenues, which necessarily increases average retail rates (given
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54 that average rates are simply total revenues divided by total retail sales).¹² Thus, while these
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59 ¹² It may not always be the case that a decoupling mechanism results in increased customer bills. In particular, if a
60 utility without decoupling collects more than its revenue requirement, the implementation of decoupling would
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measures may mitigate the impact of PV on shareholders, tradeoffs exist in the form of increases in average retail rates (albeit fairly modest ones for the scenarios examined here) above and beyond any rate increases that occur owing to customer-sited PV. In particular, excluding the case of RPC decoupling without a k-factor, the decoupling and LRAM cases result in additional rate increases of 0.07 to 0.08 cents/kWh (0.5% to 0.6%) for the SW Utility and 0.03 to 0.08 cents/kWh (0.2% to 0.5%) for the NE Utility. The fact that the increase in rates needed to achieve ROE comparability is similar between the two utilities, even though ROE must increase to a greater degree for the NE Utility, reflects the relatively small ratebase of the NE Utility compared to the SW Utility.

3.2 Shareholder-incentive mechanisms may be used to create utility earnings opportunities from customer-sited PV

While decoupling and LRAM mechanisms may mitigate the revenue erosion from demand-side resources such as PV and EE, they do not address the other fundamental disincentive that the traditional electric utility business model creates towards those resources. Namely, those resources, to the extent they defer capital expenditures by the utility, also erode the utility's opportunity to generate earnings from those capital investments. One solution to correcting that incentive misalignment is to allow the utility to collect additional revenues for successful implementation of EE programs or achievement of energy-savings goals, thereby creating positive earnings opportunities from EE investments by the utility.

Such "shareholder incentive mechanisms" for EE have been used in many forms over the past two decades. Most commonly, shareholder incentives are based on a share of EE program

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result in a refund to customers. In addition, some jurisdictions (e.g., Colorado) have authorized "dead-bands" in conjunction with decoupling to ensure that customer bills do not increase or decrease beyond a certain amount (e.g., 2%).

costs or are calculated as a portion of the net benefits resulting from EE program implementation.¹³ Depending on their specific design, shareholder-incentive mechanisms may encourage utilities to meet or exceed energy-savings targets (e.g., performance targets or cost-bonus mechanisms), invest shareholder funds in EE programs (e.g., cost-capitalization programs), or pursue efficiency options that produce the greatest net benefit (e.g., shared net benefits) (Cappers et al. 2009).

Because shareholder incentives for EE have generally been implemented in conjunction with utility-administered EE programs, we developed a mitigation case involving a shareholder-incentive mechanism for customer-sited PV implemented in conjunction with a utility-administered PV rebate program. For the purpose of isolating the impact of the shareholder incentive, we also included this rebate program in the comparison case without the shareholder incentive. Specifically, we assume that the utility offers a \$0.5/W rebate for customer-sited PV and that the shareholder incentive is equal to 10% of the rebate cost (i.e., \$0.05/W of customer-sited PV capacity installed in each year), where these additional revenues go directly to utility earnings. This is similar to a “cost capitalization” shareholder-incentive mechanism, as has been used for utility-administered EE programs.

As shown in Figure 2, implementation of the modeled shareholder-incentive mechanism increases both utilities’ average achieved earnings, relative to what occurs with 10% PV and no shareholder incentive.¹⁴ Under the specific shareholder-incentive mechanism modeled here,

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¹³ As of July 2013, 28 states had approved a shareholder-incentive mechanism for at least one utility: 8 states with incentives based on a percentage of EE program costs, 13 states with incentives based on shared net benefits, 4 states with incentives based on a percentage of avoided costs, and 3 states with incentive mechanisms approved but specifics yet to be determined (IEE 2013).

¹⁴ We focus here on achieved earnings over the first 10 years, as that is the period over which shareholder incentives are provided (given that they are tied to administration of the PV rebate program, which is offered only over the initial 10 years). Additional earnings erosion from customer-sited PV occurs in the second 10-year period owing to deferral of capital expenditures in those years (Satchwell et al. 2014).

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4 earnings are not fully restored to the level achieved with no PV; naturally, the extent of earnings
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6 gains is a function of the design of the modeled shareholder-incentive mechanism, where greater
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8 or lesser earnings gains could be achieved simply by increasing or decreasing the specified
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10 \$0.05/W shareholder incentive. However, shareholder incentives are generally not intended to
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12 achieve complete earnings comparability but to compensate the utility only for the portion of
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14 earnings erosion associated with deferred/avoided capital expenditures (i.e., the lost earnings
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16 opportunities effect).
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21 As in the case of decoupling and LRAMs, any increase in achieved earnings associated
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23 with a shareholder-incentive mechanism is the direct result of increased utility revenues, which
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25 by definition implies an increase in average retail rates and thus a tradeoff between the impacts
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27 on shareholders and ratepayers. For the specific shareholder-incentive mechanism modeled here,
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29 the shareholder incentives increase average retail rates by 0.04 cents/kWh for the SW Utility and
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31 0.05 cents/kWh for the NE Utility (in addition to the increases that occur because of customer-
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33 sited PV under base-case assumptions).
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41 *3.3 Alternative ratesetting approaches may also significantly mitigate ROE impacts from* 42 43 *customer-sited PV* 44

45 Similar to decoupling and LRAMs, the mitigation measures in this section may also
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47 mitigate the revenue erosion from customer-sited PV and the associated impacts on shareholder
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49 ROE. However, while decoupling and LRAMs achieve that outcome by potentially increasing
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51 revenue collection through rate adjustments in between rate cases, the mitigation measures
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53 considered in this section do so by reducing the amount of time between when utilities incur
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55 costs and when those costs are reflected in rates. These “alternative ratesetting approaches”
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4 include more-frequent filing of rate cases, use of current or future test years in rate cases, and
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6 reduced regulatory lag between filing of rate cases and implementation of new rates. Alternative
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8 ratesetting approaches such as these have been discussed as ways to address the disincentive for
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10 utilities to pursue EE, and they might similarly be considered in the context of customer-sited PV
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12 (e.g., Carter 2001, Lowry et al. 2013). These measures boost utility revenues and shareholder
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14 ROE, specifically in situations where a utility's costs are growing faster than its billing
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16 determinants, as is the case for both our prototypical utilities under base-case conditions with
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21 10% PV.
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24 Our analysis shows that these alternative ratesetting approaches may mitigate the
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26 revenue-erosion effect of PV on achieved ROE. In fact, for the utilities and mitigation cases
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28 examined here, in most cases these measures more than offset the PV-induced erosion in
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30 shareholder ROE under base-case conditions and thus may be deemed as going “too far” in
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32 attempting to mitigate the effects of PV. As shown in Figure 3, the increase in ROE is most
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34 pronounced when switching from an historical test year to a future test year, resulting in an
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36 average ROE for both utilities that substantially exceeds the levels achieved under base-case
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38 conditions without PV. Switching from an historical test year to a current test year or reducing
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40 regulatory lag by 1 year also increase ROE to levels above the base-case ROE with no PV.
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42 Shortening the rate case filing frequency from 3 years to 2 years also mitigates the ROE impacts,
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44 though to a lesser extent than the other measures; for the NE Utility, this only partially restores
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46 ROE to the level achieved in the base case without PV.
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53 As with decoupling and LRAMs, improved shareholder ROE under the mitigation
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55 measures considered here occurs as a result of increased revenue collection, which by definition
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57 entails an increase in average retail rates (beyond that which occurs in the base case with no PV).
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4 The increased revenues and retail rates occur specifically in cases where the utility's costs are
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6 increasing faster than its billing determinants. Under these conditions, the observed revenue and
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8 rate increases occur because more-contemporaneous ratesetting enables the utility to reflect cost
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10 increases more quickly in its retail rates.
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16 *3.4 Higher fixed customer charges and demand charges can moderate the impacts on ROE but,*
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18 *in some cases, may exacerbate those impacts*
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21 We assess the effects of utilities increasing the share of revenue collected through
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23 demand or fixed customer charges in response to increased customer-sited PV. Because a large
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25 proportion of a utility's total costs is fixed in the short run (i.e., does not vary between rate cases
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27 with changes in consumption), revenue collection based on a fixed charge may better match
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29 revenues to costs between rate cases, especially in an environment with low load growth.
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31 Similarly, an increase in revenue collected from demand charges may reduce the impact to utility
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33 revenues, because PV-production profiles do not perfectly coincide with customer-load profiles,
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35 and therefore the reductions in customer billing demand from PV are proportionally smaller than
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37 the reductions in energy sales (Wiser et al. 2007, Ong et al. 2010). Such changes to rate designs
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39 have been proposed for mitigating the revenue-erosion impacts of EE, and they have been
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41 discussed more broadly as a strategy for better aligning utility revenues and costs (RAP 2011,
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43 EEI 2013, Hledik 2014).
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50 We specify two scenarios involving alternative rate designs – a high-demand-charge case
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52 and a high-fixed-customer-charge case – applied to all customers. Both entail shifting all non-
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54 fuel costs that were recovered through volumetric charges in the base case to either demand
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56 charges or fixed customer charges. The resulting shares of revenue collected through volumetric,
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4 demand, and fixed charges are shown in Table 2. The shift in revenue allocation from one
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6 scenario to another is more severe for the SW Utility than for the NE Utility, because the NE
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8 Utility relies on energy-market purchases to meet its entire retail sales obligation, and those costs
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10 are collected through volumetric energy charges in all cases. Finally, these rates apply to all
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12 customers (those with and without PV) and to all rate classes, though many of the rate-design
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14 discussions surrounding PV involve changes to rate designs only for customers with PV.¹⁵
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19 In general, the results of these scenarios show that shifting revenue collection from
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21 volumetric energy charges to demand charges or fixed customer charges can mitigate
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23 shareholder impacts from customer-sited PV, though the effects depend critically on specific
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25 utility circumstances; in some circumstances these measures can actually exacerbate shareholder
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27 impacts. We focus on ROE impacts, because rate-design measures principally serve to address
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29 revenue erosion rather than lost earnings opportunities.
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33 As shown in Figure 4, moving to a rate design with high fixed customer charges has
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35 dramatically different impacts on the SW Utility and NE Utility. In particular, for the SW Utility,
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37 the increased ROE resulting from a high fixed customer charge more than offsets the ROE
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39 erosion that occurs under the 10% PV scenario with base-case rate-design assumptions. In
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41 contrast, the NE Utility sees a further erosion of ROE under the high-fixed-customer-charge
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43 case.
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47 The differing results for the two utilities reflect underlying differences in the relative
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49 growth rates for number of customers and retail sales. For the years 2013 to 2032, the SW Utility
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51 has customer growth of 2.7% per year, compared to 1.7% annual growth in retail sales with 10%
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53 PV. The NE Utility has customer growth of 0.3% per year, compared to 1.0% annual growth in
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58 ¹⁵ The financial model used for this analysis does not distinguish between participants and non-participants or
59 among customer classes. However, future editions of the model and future research will explore differential rate
60 designs for customers with and without PV and for different rate classes.
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4 retail sales with 10% PV. As a result, tying revenue growth more closely to growth in the number
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6 of customers increases the SW Utility's revenue collection and better aligns revenues and costs
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8 between rate cases, while the opposite occurs for the NE Utility. These divergent results for the
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10 two utilities mirror those that occur under the mitigation scenario involving RPC decoupling
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12 without a k-factor, for the same underlying reasons.
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16 Moving to a rate design with high demand charges has a much more modest impact,
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18 compared to the high-fixed-charge scenario, resulting in a small increase in achieved ROE
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20 (relative to the base case at 10% PV penetration) for both utilities. These ROE increases reflect
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22 the fact that, for both prototypical utilities, growth in peak demand is greater than growth in retail
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24 sales with 10% PV. Tying non-fuel revenues to peak demand, therefore, allows the utility to
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26 collect greater revenues between rate cases than under the base-case rate design.
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31 Any increase in achieved ROE due to a shift towards higher fixed customer charges or
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33 demand charges results directly from increased utility revenues. As with the other mitigation
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35 measures that increase revenues, average retail rates also increase (beyond the increase that
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37 occurs in the base case with PV). Figure 4 shows that average rates increase under the high-
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39 fixed-charge scenario for the SW Utility and under the high-demand-charge scenario for both
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41 utilities. However, these rate increases represent the average increase across all customers, and
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43 the impacts may differ substantially between customers with and without PV. Therefore, this
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45 analysis cannot determine how these rate-design scenarios would affect customers without PV. In
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47 particular, the analysis cannot determine whether the rate designs would mitigate any increases
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49 in non-PV customers' rates occurring because of customer-sited PV.
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4 *3.5 Utility ownership of customer-sited PV may offer sizeable earnings opportunities, potentially*
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7 *offsetting much of the earnings impacts from PV that otherwise would occur*
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9   As with EE, customer-sited PV can erode shareholder earnings as a result of deferred or
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11 avoided capital expenditures, in addition to the earnings erosion associated with any mismatch in
12
13 PV's effect on utility costs and revenues. In order to mitigate the shareholder impacts of lost
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15 earnings opportunities resulting from EE, utilities in some jurisdictions have been allowed to
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17 finance customer EE measures and earn an authorized return on those investments. Similarly, the
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19 lost earnings opportunities resulting from customer-sited PV could be mitigated by allowing
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21 customer-sited PV to become a regulated investment opportunity for utilities (SEPA 2008, SEPA
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23 2009). This might involve full utility ownership of customer-sited PV assets, as proposed by
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25 Arizona Public Service and Tucson Electric Power, or it may consist of utility financing of
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27 customer investments, similar to the Public Service Electric and Gas Solar Loan Program.
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33   Our analysis assumes that the regulated utility is allowed to own customer-sited PV¹⁶ and
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35 earn its authorized rate of return on those assets. We consider two scenarios: one bookend
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37 scenario in which the utilities own 100% of customer-sited PV capacity in their service territories
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39 and another in which they own 10% of PV capacity. As in all other scenarios, PV systems are
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41 assumed to be installed behind the customer meter and interconnected via a standard net-
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43 metering arrangement; thus the impacts on utility-billing determinants under this mitigation
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45 scenario are the same as in the base case. However, we assume the utilities receive additional
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47 revenues from customers with PV systems that are owned or financed by the utility, and we
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49 assume those revenues are sufficient to provide the utilities both a return *of* and *on* their
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56 ¹⁶ We assume that customer-sited PV costs \$5.5/W_{dc} in 2010 and declines linearly to \$2.1/W_{dc} in 2020, which
57 corresponds to the mid-point cost-reduction case from the U.S. Department of Energy's SunShot Vision Study (DOE
58 2012). We also assume that the utility can take advantage of the 30% investment tax credit (ITC) for installations
59 prior to the end of 2016 and a 10% ITC for installations after 2016 (as would be the case for systems owned by any
60 commercial entity, including a regulated utility).
61

investment. We also assume that these additional revenues can be approximated by adding the up-front cost of the customer-sited PV systems to the utility's ratebase in the year in which the systems are installed.¹⁷ With this approach, the SW and NE Utility capital costs increase by \$2.8 billion and \$2.6 billion, respectively, under the scenario in which 100% of customer-sited PV is owned by the utility, and they increase by proportionally smaller amounts under the scenario with 10% utility ownership of customer-sited PV.

For this set of mitigation strategies, we focus on the impacts on shareholder ROE and earnings over the full 20-year analysis period, because the lost earnings opportunities associated with customer-sited PV occur over that entire span. We do not present rate impacts. We assume incremental changes to average rate impacts for these mitigation cases fall solely on PV customers, thus changes to average rates for all customers (which is what the financial model estimates) are not a meaningful measure.

Under the scenarios in which the utilities own all customer-sited PV, achieved earnings and ROE rise significantly (Figure 5). In fact, the earnings of the NE Utility, whose only other utility investments are in the distribution system, double over the 20-year analysis period. The SW Utility has a much larger ratebase prior to the addition of customer-sited PV, so the impact of utility PV ownership is less dramatic. However, the SW Utility's increase in earnings still more than offsets the reduced earnings under the base case with 10% PV. Under the arguably more realistic scenario in which the utilities own 10% of customer-sited PV, the increase in achieved earnings is only 10% of what occurs when the utilities own all PV. Thus, although achieved

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¹⁷ This modeling approach is thus akin to a cost-capitalization shareholder incentive for EE programs, where EE program costs are added to the utility ratebase and recovered from all ratepayers. In the case of utility-owned, net-metered PV, revenues required to recover the cost of utility-owned PV would, in all likelihood, be recovered only from participating customers (e.g., via on-bill financing or some other mechanism). However, for simplicity, we model revenue impacts as though they were recovered through base rates.

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4 earnings and ROE increase for both utilities, those increases do not restore profitability to the
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6 levels that occur under the base case without PV.
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11 *3.6 Automatically counting customer-sited PV towards RPS compliance can substantially*
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13 *mitigate rate impacts*
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16 The preceding mitigation measures all address impacts of customer-sited PV on utility
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18 shareholders and, in most cases, involve corresponding increases in average rates. In contrast,
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20 one option for potentially mitigating the impacts on utility ratepayers is to automatically count all
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22 customer-sited PV directly toward the utility's Renewables Portfolio Standard (RPS) compliance
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24 obligation (without requiring any explicit payment by the utility).¹⁸ Our underlying assumption,
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26 prior to mitigation, is that customer-sited PV indirectly reduces RPS compliance obligations by
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28 reducing retail sales, but Renewable Energy Credits (RECs) generated by customer-sited PV
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30 systems are assumed to remain the property of the system owner and are not automatically
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32 applied towards RPS compliance. In effect, this mitigation approach entails transferring
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34 ownership of RECs as a condition of receiving service under net metering, thereby reducing the
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36 number of RECs that the utility would otherwise be required to procure to meet its RPS
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38 obligations.¹⁹
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45 As shown in Figure 6, applying RECs generated by customer-sited PV toward the
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47 utilities' RPS compliance obligations without requiring any explicit utility payment offsets a
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53 ¹⁸ Although not considered here, multipliers that are applied to RECs from customer-sited PV for purposes of RPS
54 compliance would similarly serve to mitigate the rate impacts from customer-sited PV by reducing RPS compliance
55 costs.

56 ¹⁹ In general, regulators allow customer-sited PV to count towards utility RPS compliance; however, in most cases,
57 ownership of the associated RECs remains with the owner of the system, unless the utility provides some kind of
58 direct payment or explicit financial incentive. Recently, however, Arizona Public Service proposed an approach,
59 termed "track and record," whereby all distributed solar in its service territory would apply towards its RPS
60 requirements, regardless of whether or not the systems received any direct financial incentive from the utility.
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substantial portion of the increases in average retail rates that otherwise occur in conjunction with customer-sited PV. In the case of the SW Utility, the rate impacts are reduced by roughly half, relative to the base case with 10% PV. For the NE Utility, the rate impacts are offset almost entirely. The degree of mitigation depends, among other factors, on the cost of avoided RECs, which in turn reflects the cost of renewable energy relative to non-renewable generation: when RECs are expensive, allowing customer-sited PV to count toward the RPS leads to a greater reduction in utility costs and thus a greater reduction in average rates. Thus, the mitigation is larger for the NE Utility, where assumed REC prices are higher (\$35/MWh) than for the SW Utility (with an “effective” REC price of \$23/MWh).²⁰ By the same logic, the results shown in Figure 6 would differ if other assumptions were made about the underlying cost of RECs (or, more generally, about the cost of renewable energy relative to the cost of non-renewable energy that RPS procurement displaces). Applying customer-sited PV toward utility RPS obligations does not impact utility ROE or earnings, because we assume that the avoided RPS compliance costs are an annual pass-through to customers.²¹

4. Discussion

Our results show that, depending on the particular design, mitigation approaches can be employed to address revenue erosion, lost earnings opportunities, and increases in average retail rates resulting from the addition of customer-sited PV. These mitigation approaches entail a

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²⁰ For simplicity of modeling, we apply this REC price to all RPS obligations of the NE Utility; had we assumed higher REC prices, such as those typical of solar set-aside markets, the mitigation of rate impacts would be even greater. The SW Utility is assumed to purchase RECs and energy as a bundled product, and thus the effective REC price is simply the difference between the cost of power-purchase agreements (PPAs) for renewables and the cost of conventional generation.

²¹ We assume that the SW Utility meets its RPS obligation through a combination of utility-owned renewable generation and PPAs but that PPAs are the marginal resource and are treated as pass-through costs.

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4 variety of important tradeoffs in addition to the previously discussed tradeoffs between utility
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6 shareholders and ratepayers.
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9 More frequent filing of rate cases can reduce the incentives for utilities to minimize costs
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11 between rate cases and could potentially lead to perpetual rate cases (Carter 2001), which are
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13 costly and time consuming for regulatory staff and intervenors. Future test years require the use
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15 of sophisticated cost forecasts for establishing revenue requirements and billing determinants,
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17 which can be contentious (Costello 2013). Administrative process requirements can limit the
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19 potential for reducing regulatory lag between when new rates are adopted and when they go into
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21 effect.
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26 Important policy tradeoffs arise in connection with increased fixed customer charges or
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28 demand charges and correspondingly reduced volumetric energy charges. First, higher fixed
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30 charges reduce the incentive for customers to conserve energy and invest in PV. Alternatively,
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32 high fixed charges might motivate customers to invest in onsite generation with storage and to
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34 bypass the utility altogether, which would further exacerbate the problems that the change in rate
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36 design was intended to address. These potential dynamics highlight one important difference
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38 between high fixed customer charges and RPC decoupling: although both measures similarly tie
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40 utility revenues more closely to the number of customers, RPC decoupling maintains the same
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42 utility revenues more closely to the number of customers, RPC decoupling maintains the same
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44 volumetric charges for customers and thus does not diminish customers' incentive for EE and
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46 distributed generation (or provide an increased incentive for grid defection). A separate but
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48 related policy tradeoff is that, in general, increased fixed customer charges limit customers'
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50 ability to manage their total utility bills, which may raise concerns with respect to low- and
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52 fixed-income customers. Increased demand charges may entail less severe tradeoffs than those
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54 associated with high fixed-customer charges. Many utilities, however, do not have the metering
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4 capabilities to record and bill demand for residential customers, thus a greater reliance on
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6 demand charges for residential customers would require deployment of the necessary metering
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8 and billing systems. Residential customers may be unfamiliar with their demand and unable to
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10 manage it. Although we do not examine these various policy tradeoffs in the present analysis, we
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12 highlight their potential importance for decision makers and for future studies.
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16 Utility ownership or financing of customer-sited PV may raise significant policy and
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18 regulatory questions, including whether a regulated utility should be allowed to provide a service
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20 similar to that provided by unregulated, competitive companies (including, in some cases,
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22 unregulated affiliates of the utility). In the case of a regulated utility, ratepayers would generally
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24 bear some portion of the risk of such investments. Furthermore, some states no longer allow
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26 regulated utilities to own generation (as in our NE Utility), in which case utility ownership of
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28 customer-sited generation may be prohibited or would require special authorization.²²
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32 Finally, crediting customer-sited PV towards RPS compliance also involves a variety of
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34 tradeoffs. First, it is tantamount to reducing existing RPS requirements, because it reduces the
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36 amount of renewable energy the utility would otherwise procure (without increasing customer-
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38 sited PV). Second, transferring REC ownership to the utility would limit customers' ability to
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40 make environmental or clean-energy claims, because they would no longer retain ownership of
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42 the environmental attributes of their PV systems. This could raise concerns about unlawful
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44 taking of private property.²³ To the degree that customers' decisions to add PV are driven by their
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46 desire to retain or sell RECs from their PV systems, such an arrangement could degrade the value
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55 ²² See Wiser et al. (2010) for examples of utility ownership of customer-sited PV, including the Massachusetts
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57 Green Communities Act of 2008, which allows the state's regulated electric-distribution companies to construct,
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59 own, and operate up to 50 MW of solar generation each.

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61 ²³ Similar issues with environmental claims arise in the context of utility-funded PV incentive programs, in which
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63 REC ownership often vests to the utility, and in the context of third-party-owned systems, where REC ownership
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65 often vests with the finance provider rather than the host customer.

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4 of PV to the customer and reduce deployment. For these reasons and others, such transfers of
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6 REC ownership have often been controversial (Holt et al. 2006).
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10 11 **5. Conclusions and policy implications** 12 13

14 The findings from our analysis suggest several policy implications. First, many of the
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16 mitigation measures deployed and implemented for EE are also applicable to addressing the
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18 negative financial impacts of net-metered PV. In fact, the analysis demonstrates that many of
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20 these mitigation measures entirely negate ROE or earnings impacts. For example, RPC
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22 decoupling with a k-factor can mitigate ROE impacts. In addition, our analysis demonstrates a
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24 variety of effective measures that constitute arguably “incremental” changes to utility business or
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26 regulatory models as opposed to wholesale paradigm shifts. The efficacy of these measures
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28 shows that, contrary to the suggestions of some utilities, net-metered PV might not necessarily
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30 represent an “existential threat” to the underlying regulatory and utility business model (Kind
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32 2013). Regulators may wish to investigate existing, incremental approaches before pursuing
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34 more fundamental and wholesale changes to the regulatory paradigm.
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41 Second, the analyzed mitigation measures are relatively narrow in the scope of issues
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43 they address (i.e., targeting revenue erosion, lost earnings opportunities, and increased rates), and
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45 we examine each measure in isolation. However, several measures could be coupled with each
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47 other (e.g., combining RPC decoupling with shareholder incentives), or with other mitigation
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49 measures, as part of a more comprehensive solution. Regulators should, in particular, consider
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51 “comprehensive business models” that address concerns of ratepayers and shareholders.
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55 Third, the potential efficacy of these measures may vary considerably depending on their
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57 design and the specific utility circumstances. For example, within our analysis, when RPC
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4 decoupling is implemented in conjunction with customer-sited PV, the result can range from a
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7 worsening of utility profitability to a dramatic improvement in profitability beyond the level
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9 achieved without PV, depending on the utility and the choice of design elements (e.g., a k-
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11 factor). This suggests the need for utility-specific analysis and the need for regulators to consider
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13 design options carefully. This analysis provides an example of how regulators can perform the
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15 modeling necessary to understand the implications of design elements.
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19 Finally, many mitigation strategies entail substantive tradeoffs. These tradeoffs may exist
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21 between ratepayers and shareholders; for example, decoupling and other mitigation measures
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23 that involve changes to the way the utility collects revenue may increase average retail rates.
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25 Important tradeoffs may also exist among competing policy and regulatory objectives, for
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27 example, among the various principles of ratemaking or between policy objectives associated
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29 with ratepayer equity and environmental goals. Given the complex set of issues involved in
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31 implementing many of the possible mitigation measures, regulators may wish to address
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33 concerns about the ratepayer and shareholder impacts of customer-sited PV within the context of
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35 broader policymaking and ratemaking processes.
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Table 1. Mitigation Cases and Targeted Intent

Mitigation Measure	Description	Revenue Erosion	Lost Earnings Opportunities	Increased Rates
Revenue-per-Customer (RPC) Decoupling	Revenue decoupling is implemented by setting a revenue per-customer target in rate cases and adjusting rates annually between cases to collect revenues at the target level	●		○
Lost Revenue Adjustment Mechanism (LRAM)	Rates are adjusted annually to compensate the utility for the incremental loss of revenue occurring as a result of customer-sited PV	●		○
Shareholder Incentive	Utility shareholders receive additional earnings for the successful achievement of policy goals (in this case, related to customer-sited PV deployment)		●	○
Shorter Rate Case Filing Frequency	The period between GRC filing is reduced	●		○
No Regulatory Lag	The lag between the filing of GRCs and implementation of new rates is eliminated	●		○
Current & Future Test Years	Current or future test years are used to set utility revenue requirement during GRCs	●		○
Increased Demand Charge & Fixed Charge	An increased share of non-fuel costs is allocated to demand or fixed customer charges	●		○
Utility Ownership of Customer-Sited PV	The utility owns customer-sited PV systems, leases the systems back to the host customers or to intermediaries, and earns a return on the assets		●	○
Customer-Sited PV Counted toward RPS	All net-metered PV counts toward the utility's RPS compliance obligations			●

● Primary intended target of mitigation measure

○ May exacerbate impacts of customer-sited PV

Figure 1. Mitigation of PV Impacts through Decoupling and LRAM

Figure 2. Mitigation of PV Impacts through Shareholder Incentives

Figure 3. Mitigation of PV Impacts through Alternative Ratesetting Approaches

Table 2. Rate Design Mitigation Cases (Percent of Total Utility Revenues)

	Base Case	High Demand Charges	High Customer Charges
SW Utility			
Volumetric Charges	77%	24%	24%
Demand Charges	11%	63%	11%
Customer Charges	12%	12%	65%
NE Utility			
Volumetric Charges	84%	64%	64%
Demand Charges	8%	28%	8%
Customer Charges	8%	8%	28%

Figure 4. Mitigation of PV Impacts through Increased Customer Charges or Demand Charges

Figure 5. Mitigation of PV Impacts through Utility Ownership of Customer-Sited PV

Figure 6. Mitigation of PV Impacts by Applying RECs from Customer-Sited PV towards RPS Obligations