

The Impact of Rate Design and Net Metering on the Bill Savings from Distributed PV for Residential Customers in California

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Abstract

Net metering has become a widespread mechanism in the U.S. for supporting customer adoption of distributed photovoltaics (PV), but has faced challenges as PV installations grow to a larger share of generation in a number of states. This paper examines the value of the bill savings that customers receive under net metering, and the associated role of retail rate design, based on a sample of approximately two hundred residential customers of California's two largest electric utilities. We find that the bill savings per kWh of PV electricity generated varies by more than a factor of four across the customers in the sample, which is largely attributable to the inclining block structure of the utilities' residential retail rates. We also compare the bill savings under net metering to that received under three potential alternative compensation mechanisms, based on California's Market Price Referent (MPR). We find that net metering provides significantly greater bill savings than a full MPR-based feed-in tariff, but only modestly greater savings than alternative mechanisms under which hourly or monthly net excess generation is compensated at the MPR rate.

Keywords: Photovoltaics; Retail rate design; Net metering

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1. Introduction

An increasing number of states use net metering to compensate electricity produced by photovoltaic (PV) system owners.¹ Though specific design details vary, net metering allows customers with PV systems to reduce their electric bills by offsetting their consumption with PV generation, independent of the timing of the generation relative to consumption – in effect, selling PV generation to the utility at the customer’s marginal retail electricity rate (Rose et al. 2009).

Though net metering has played an important role in jump-starting the PV market in the United States (U.S.), challenges to net metering policies have emerged in a number of states and contexts, and alternative compensation methods are under consideration. Moreover, one inherent feature of net metering is that the value of the utility bill savings it provides to customers with PV depends heavily on the structure of the underlying retail electricity rate, as well as on the characteristics of the customer and PV system. Consequently, the bill-savings value of net metering – and the impact of moving to alternative compensation mechanisms – can vary substantially from one customer to the next. For these reasons, it is important for policymakers and others that seek to support the development of distributed PV to understand both how the bill savings benefits of PV vary under net metering, and how the bill savings under net metering compare to savings associated with other possible compensation mechanisms.²

To advance this understanding, we analyze the bill savings from PV for residential customers of California’s two largest electric utilities, Pacific Gas and Electric (PG&E) and Southern California Edison (SCE), based on actual hourly load data from 215 customers within the two utilities’ service territories. We focus on these two utilities,

both because we had ready access to a sample of high temporal resolution load data, and because their service territories are the largest markets for residential PV in the country.

We first compute the bill savings based on current net metering rules and retail electricity rates, and then examine a number of critical underlying issues that influence the value of bill savings under net metering, including retail rate design, PV system size, PV orientation, and customer load characteristics. Next, we compare the value of the bill savings under net metering to three potential alternative compensation mechanisms, each of which credits some or all PV production at prices based on the state's Market Price Referent (MPR) – the price intended to represent long-run avoided generation costs used to evaluate wholesale contracts with renewable generators (CPUC 2009).

The boundaries and limitations of the analysis presented in this article should be clearly acknowledged. First, the current residential retail rates offered by PG&E and SCE are unique in several respects, and thus the specific findings presented in this report cannot necessarily be generalized to apply to other utilities or states. Second, the analysis is based on a sample of customers that, while geographically diverse, may not be statistically representative of the entire population of residential customers in either PG&E's or SCE's service territories, and may not be representative of the current population of residential customers with PV systems. Third, the analysis focuses exclusively on the value of the bill savings provided to customers with PV; it does not consider the overall cost-effectiveness of distributed PV for an individual customer, nor does it consider the value or cost-effectiveness of distributed PV from the perspective of the utility, non-participating ratepayers, or society-at-large. Finally, in comparing net metering to several alternative compensation mechanisms, we focus exclusively on the value of the bill savings or bill credits provided to customers through each compensation mechanism; net metering may provide other advantages and disadvantages (both

financial and otherwise) relative to the alternative compensation mechanisms considered, but these are not covered in the analysis presented here. For example, alternatives to net metering that entail explicit sales of electricity by the customer to the utility may be subject to income taxes, may give rise to federal regulatory compliance requirements, and could potentially interfere with common customer financing mechanisms like third-party power purchase agreements (PPAs)/leases and property assessed clean energy (PACE) financing.

The remainder of this article is organized as follows. Section 2 briefly summarizes the existing literature addressing the impact of retail rate design and net metering on the bill savings from PV. Section 3 describes the data used within our analysis and the basic analytical framework used to calculate customer utility bills and the value of the bill savings from PV under net metering and under each of the alternative compensation mechanisms. Section 4 presents intermediate results showing how the least-cost rate, among the set of residential retail rates offered by each utility, varies with PV system size for customers with net metered PV systems. Section 5 describes the value of the bill savings from PV under net metering and the associated variability across customers, including several sensitivity analyses to explore how different rate choices and PV panel orientations impact the bill savings. Section 4 also examines three alternative compensation mechanisms for distributed PV, and compares the value of the bill savings between each of these alternatives and net metering. Finally, conclusions and policy implications are presented in Section 6.

2. Literature Review

This paper, which is based upon a more expansive analysis presented in Darghouth et al. (2010), builds on a body of literature that has approached different aspects of net

metering, rate design, and renewable electricity generation. Most closely related, perhaps, is a recent cost-effectiveness study of net metering in California (Energy and Environmental Economics 2010), which evaluated the total costs and benefits to the utility and its ratepayers of compensating hourly excess PV generation at retail rates, rather than at avoided costs. In comparison, the present paper estimates the total bill savings under net metering, including the bill savings both from directly offsetting contemporaneous usage and from compensating hourly excess PV generation at retail rates.

Other prior studies have investigated the customer economics of PV under net metering and its relationship to retail rate structures. Of particular note, Borenstein (2007) calculated the bill savings for net-metered residential customers of PG&E and SCE with 2 kW PV systems, in order to determine whether mandatory time-of-use (TOU) rates for PV customers would cause a reduction in bill savings. The present study relies on the same sample of customer load data as used in Borenstein (2007), updating the analysis based on the set of residential retail rates offered by PG&E and SCE in early 2010, and extending the analysis by evaluating bill savings under varying PV system sizes and by comparing the value of the bill savings between net metering and several alternative compensation mechanisms.

Other related studies include Hoff and Margolis (2004), Borenstein (2005), Borenstein (2008), and Bright Power Inc. *et al.* (2009), all of which show that net-metered time-of-use and/or real-time pricing rates can increase the value of PV generation to the customer. MRW and Associates (2007), meanwhile, evaluate which retail rate structures provide the greatest benefits to different classes of PV customers in California. Mills *et al.* (2008) investigate the impact of retail rate structure on the value of bill savings for commercial customers in California, focusing in part on the extent to

which PV can reduce customer demand charges. VanGeet *et al.* (2008) calculate the rate impacts of demand charges and energy charges on the bills of commercial customers with PV systems in the city of San Diego. Finally, Cook and Cross (1999) estimate the costs and benefits of net metering in Maryland from the perspectives of participating customers, non-participants, and utility shareholders, based on a hypothetical net-metered PV customer.

3. Data and Methodology

3.1. Utility Tariff Descriptions

The analysis presented in this paper is based on the residential retail electricity rates and net metering rules offered by PG&E and SCE, as of March 2010. For both utilities, the default residential tariff is a non-time-differentiated (i.e., “flat”) inclining block rate, with five usage tiers and increasing prices for usage within each successive tier, the E-1 and D rate for PG&E and SCE, respectively. The lowest tier (Tier 1) is referred to as the baseline allotment; its size varies according to the region in which the customer is located and is designed to cover 50-60% of average monthly electricity consumption for customers in the region (CPUC 2010). The other four tier levels are defined as percentages of the baseline, with Tier 5 defined as all usage >300% of the baseline. A unique feature of the two utilities’ rates are that the prices for successive usage tiers are quite steeply inclined, rising from \$0.12/kWh in Tier 1 to \$0.50/kWh in Tier 5 for PG&E, and from \$0.13/kWh to \$0.31/kWh for SCE.

Both utilities also offer residential time-of-use (TOU) rates – the E-6 and the TOU-D-T rate for PG&E and SCE, respectively – under which prices vary according to both the season (summer vs. winter) and the time of day, with either two or three TOU periods during each day, depending on the utility. The TOU rates also include usage tiers within

each TOU period, and monthly consumption within each TOU period is charged according to the tier within which it falls. One important difference between PG&E's and SCE's residential TOU rates is that PG&E's has five usage tiers within each TOU period (similar to its default residential tariff), whereas SCE's has only two usage tiers within each TOU period. Further details on the residential electricity rates offered by PG&E and SCE can be found in Appendix A.

The utilities' residential net metering tariffs allow customers to offset volumetric charges within each billing period, but fixed per-customer charges cannot be offset, and minimum monthly charges still apply. For customers taking service on a TOU rate, the netting and calculation of bill credits occurs separately within each TOU period, so that PV generation is credited based on the TOU period in which it occurs. Any excess bill credit at the end of a billing period is "rolled over" to the next billing period; however, at the end of the year, any excess bill credits are forfeited.³ That latter provision provides an economic incentive for customers to size their PV systems to meet less than their total annual energy consumption.

3.2. Market Price Referent (MPR)

The alternative compensation mechanisms considered in this paper are based on California's Market Price Referent (MPR), as described further in the Appendix. The MPR is a price established by the California Public Utilities Commission (CPUC) and updated each year. It is intended to represent the long-term market price of electricity, based on the ownership, operating, and fixed-price fuel costs for a new natural gas-fired combined cycle gas turbine (CCGT). The original purpose of the MPR was to serve as a benchmark for assessing the above-market costs of contracts with renewable generators signed by the state's investor-owned utilities for complying with California's renewable

portfolio standard (RPS). More recently, it has become the basis for the contract price under California's small renewable generator feed-in tariff program. That program, which is available to certain solar and other renewable generation projects smaller than 1.5 MW, provides an alternative to net metering under which customers can opt to either sell all electricity generated by their system under an MPR-based feed-in tariff or use their renewable generator to first meet on-site load and sell only excess generation to the utility under the feed-in tariff. Two of the alternative compensation mechanisms considered in this report are modeled after, though not identical to, the two compensation options under the state's existing feed-in tariff program.

The MPR has several elements. The "baseload" MPR price is based on the long-term cost of a CCGT and varies according to the year in which the renewable energy project enters commercial operation and the contract length. For the purpose of our analysis, we use the 2009 MPR baseload price for a 20-year contract with deliveries beginning in 2010, equal to \$0.09674/kWh. To establish the MPR price for a specific renewable energy generator or contract, the baseload MPR price is adjusted according to the Time-of-Delivery (TOD) period within which electricity is generated, by multiplying the baseload MPR rate by the utility-specific TOD adjustment factor. Similar to the utilities' retail TOU rates, the MPR TOD adjustment factors provide higher levels of compensation during summer afternoon hours than at other times, although specific structural details (e.g., the definitions of the time periods and price spread between time periods) differ between the retail TOU rates and the MPR TOD factors.

3.3. Customer Load Data and Simulated PV Generation Data

Our analysis relies on 15-minute interval load data from a sample of residential customers located throughout the service territories of PG&E and SCE, spanning the 12-

month period from October 2003 through September 2004. These load data were collected through a previous study on critical peak pricing (Charles River Associates, 2005), and were made available for the present analysis. After all data cleaning operations, 215 customers (118 PG&E customers and 97 SCE customers) were ultimately used in this analysis.

The customers within the data sample are somewhat larger than the typical residential customer of either utility, but are smaller than the typical net-metered residential customer. The PG&E customers in our sample have an average monthly consumption of 667 kWh, which is approximately 30% higher than the average PG&E residential customer, but is 36% below the average for PG&E residential customers with net metered PV systems. Similarly, the SCE customers have an average monthly consumption of 730 kWh, which is 38% higher than the average SCE residential customer, but 42% below the average for SCE residential customers with net metered PV systems (MRW & Associates, 2007; Energy and Environmental Economics, 2010; DeBenedictis 2010).

The residential customers in the data sample did not have PV systems installed. Thus, for each customer, hourly PV production was simulated using the National Renewable Energy Laboratory (NREL)'s PVFORM/PVWatts Model and the National Solar Radiation Database (NREL 2007, Denholm et al. 2009, NREL 2010). The simulated PV production data consists of hourly AC electricity generation at 73 weather stations located throughout California, for the same 12-month period as the customer load data (October, 2003 through September, 2004). We obtained simulated PV production data for three PV panel orientations. For our base case analysis, we used simulated production for a south-facing (180° azimuth) system with a 25° tilt, as this is the azimuth that produces the maximum annual electricity generation per kW of installed capacity in the northern hemisphere, and 25° is a typical angle for a sloping rooftop. We

also conducted sensitivity analyses for a 240° azimuth (approximately west-southwest) with a 25° tilt, and flat-mounted system (i.e., tilt=0°). Both alternative PV orientations yield less annual PV generation than our base case orientation (11% and 10% less, respectively, in the median case). The southwest orientation was chosen because systems facing in that direction receive more sunlight during the summer on-peak TOU period when retail electricity rates are highest under the utilities' TOU rates (Borenstein 2008). The no-tilt orientation was chosen to represent systems installed on flat roofs, which are common in some parts of California.

The simulated PV production data is based on a 1 kW system. For each paired set of customer load and PV production data, the simulated hourly PV production was then scaled so that total annual PV generation would be equal specific percentages of the customer's annual consumption (herein referred to as "PV-to-load ratio"). Three PV-to-load ratios – 25%, 50%, and 75% – were used throughout our analysis. Among the actual population of residential PV customers in California, the average PV-to-load ratio is approximately 56% for PG&E residential customers and 62% for SCE residential customers (DeBenedictis 2010). We did not include a case with a 100% PV-to-load ratio, as systems of this size would, under net metering rules as of 2010, result in forfeited bill credits at year-end for many customers.

3.4. Calculating Utility Bills and the Value of Bill Savings

We calculated annual utility bills for each customer, both with and without a PV system, under each of the currently available residential retail rates offered by the utility in whose service territory the customer is located. The utility bill savings from PV for each customer is expressed in terms of the reduction in the annual utility bill per kWh generated by the PV system (i.e., in units of \$/kWh). This allows for a direct

comparison of bill savings between customers with different loads as well as between alternate PV-to-load ratios. Unless otherwise noted, we assume that customers choose the least-cost rate before and after PV installation.

For each customer, bill savings were calculated for each permutation of:

- PV-to-load ratio (25%, 50%, and 75%);
- PV orientation (south-facing at a 25° tilt, southwest facing at a 25° tilt, and flat);
and
- PV compensation mechanism (net metering and each of three alternatives).

Under the three hypothetical alternatives to net metering considered in this analysis, some or all PV production is compensated at an MPR-based rate (rather than at the retail electricity rate, as under net metering; see Appendix for details). For the purpose of this analysis, we assume that all compensation is provided in the form of bill credits applied against the customer's utility bill. The three alternative compensation mechanisms are:

- (1) An MPR-based feed-in tariff, under which the customer is credited for all PV generation at the MPR rate, with applicable time-of-day multipliers;
- (2) Hourly netting, whereby PV production can offset up to 100% of customer usage within each hour, but any excess hourly production is credited at the applicable MPR rate; and
- (3) Monthly netting, whereby PV production can offset up to 100% of customer usage within each month (or, for customers on a TOU rate, within each TOU period of each month), but any excess production is credited at an MPR-based rate.

The first two of these alternative compensation mechanisms are modeled after – though not identical to – California's existing feed-in tariffs for small renewable generators,

which provide customers with certain solar and other renewable generation projects the option to either sell all electricity generated by their system at MPR-based prices or use their renewable generator to first meet on-site load and sell only the excess generation to the utility at MPR-based prices. The third option is a variant of net metering that exists in a number of states, such as Alaska, Georgia, Missouri, Nebraska, North Dakota, and Oklahoma, under which customers receive payment for monthly excess generation at an avoided cost based rate, rather than rolling the net excess generation forward to the following month and thereby receiving compensation at retail electricity prices.

4. Bill Savings under Net Metering

4.1. Least-Cost Rate Choice

As indicated above, throughout most of our analysis we assume that customers select the least-cost rate, both before and after PV installation. Figure 1 shows the percentage of customers in the sample for which the TOU rate would be the least-cost option, across PV-to-load ratios, assuming net metering and the base case PV panel orientation. It is important to reiterate that the specific numerical results presented here reflect the composition of our customer sample, and cannot necessarily be generalized to the broader population of residential customers in either utility's service territory.

Notwithstanding this caveat, the results in Figure 1 clearly show that, for customers of both utilities, the percentage of customers for which TOU is least-cost increases steadily with PV-to-load ratio, such that, at a 75% PV-to-load ratio, the TOU rate would be least-cost for roughly 80% of the PG&E customers and 100% of the SCE customers in the sample. The logic underlying this trend is simply that, at a low PV-to-load ratio, most customers in the sample would have too much usage during high-priced TOU periods for the TOU rate to be least-cost. However, as the PV system increases in size,

it disproportionately reduces the customer's net consumption during high-priced TOU periods, driving down the annual bill on the TOU rate faster than on the flat rate. Figure 1 also illustrates that, at any given PV-to-load ratio, the percentage of customers for which the TOU rate is least-cost is greater for SCE than PG&E. This trend is largely attributable to differences in the specific structure of the two utilities' TOU rates – namely, the fact that SCE's TOU rate has only one TOU period (the summer peak period) with prices higher than the flat rate, while PG&E's TOU rate has two TOU periods (the summer peak and summer part-peak periods) with prices higher than the flat rate.

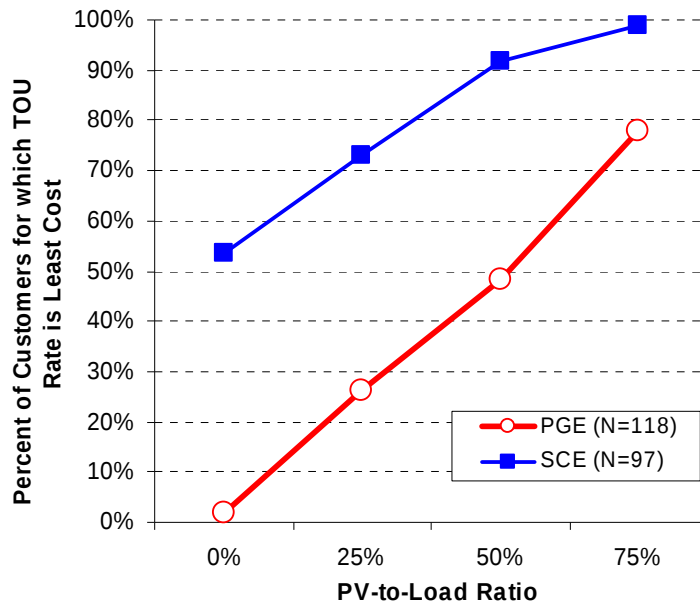


Figure 1. Least-Cost Rate Choice at Varying PV-to-Load Ratios

4.2. Bill Savings under Base Case Assumptions

Across the three PV-to-load ratios examined, the median bill savings per kWh of PV generation ranges from \$0.19-\$0.25/kWh for the PG&E customers in our sample, and from \$0.20-\$0.24/kWh for the SCE customers (see Figure 2). However, at each PV-to-

load ratio, the distribution in bill savings across customers is wide. This variation is attributable primarily to differences in customer usage level – where bill savings are greatest for high-usage customers who are able to offset consumption in high-priced usage tiers (see Figure 3). For example, at a PV-to-load ratio of 50%, the value of bill savings among the PG&E customers in our sample rises from a low of approximately \$0.12/kWh for low-usage customers in Tier 1 to \$0.36-\$0.46/kWh for high-usage customers in Tier 5. For SCE, the trend is noticeably less pronounced, due primarily to the fact that SCE’s usage tiers are less steep than PG&E’s: at a 50% PV-to-load ratio, the bill savings for the SCE customers in our sample rises from approximately \$0.14/kWh for customers in Tier 1 to \$0.24-0.29/kWh for customers in Tier 5.

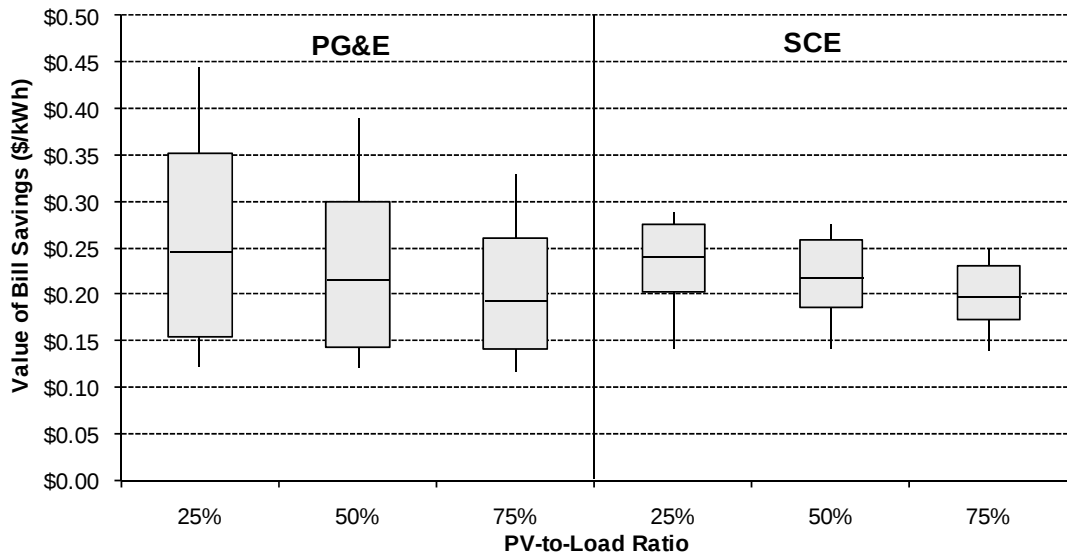


Figure 2. Distribution in Bill Savings under Net Metering and Base-Case Assumptions. Box plots identify the 10th, 25th, 50th, 75th, and 90th percentile values.

Figure 2 and Figure 3 both indicate that the bill savings per kWh produced by the PV system decline with PV system size. This phenomenon is also a consequence of the inclining usage tiers used within the utilities’ residential retail tariffs; as PV generation increases, the customer faces a progressively lower marginal price for its net consumption, and thus receives progressively lower incremental bill savings. As shown

in Figure 2, an increase in the PV-to-load ratio from 25% to 75% results in a decline in the median per-kWh value of bill savings from \$0.25/kWh to \$0.19/kWh for the PG&E customers in our sample, and from \$0.24/kWh to \$0.20/kWh for the SCE customers in our sample. However, the drop in per-kWh bill savings with increasing PV system size is greater for high-usage customers – especially for high-usage PG&E customers. For example, among the 10% of PG&E customers in our sample with the highest consumption, the per-kWh bill savings declines from \$0.45/kWh to \$0.33/kWh between a 25% and 75% PV-to-load ratio (see Figure 2). Among the SCE customers in our sample, the corresponding decline is from \$0.29/kWh to \$0.25/kWh.

The median bill savings of the customers in our sample likely understates the actual bill savings received by the actual population of residential PV customers of the two utilities, since the customers in our sample are smaller consumers than typical residential PV customers (DeBenedictis 2010).

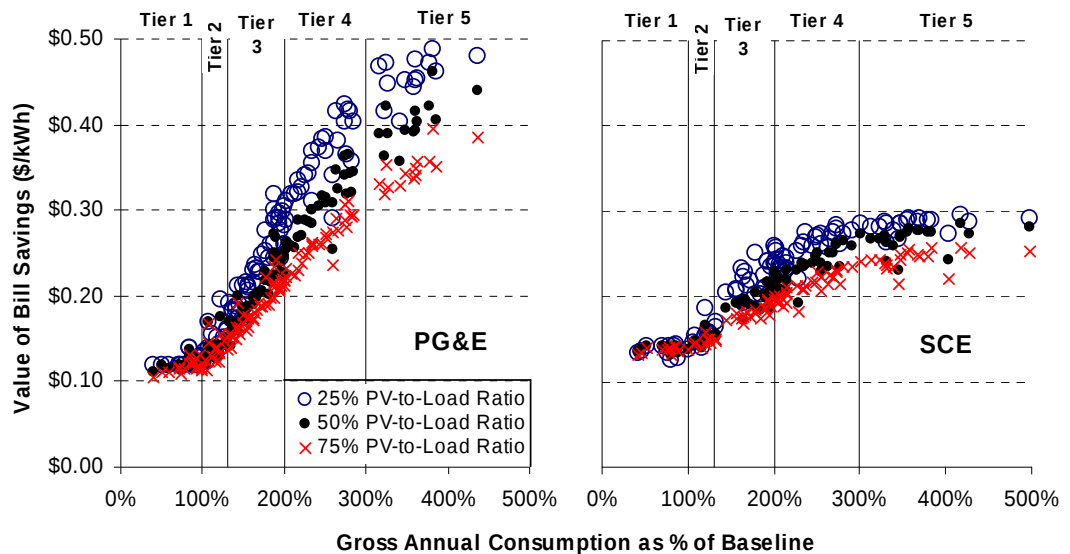


Figure 3. Variation in Bill Savings with Customer Gross Annual Consumption

4.3. Sensitivity Analyses: Sub-Optimal Rate Selection

The base case analysis assumes that customers chose the least-cost rate before and after installation of their PV systems. Given that customers may not always make the optimal rate selection, however, we also calculated the value of bill savings assuming that all customers choose the most expensive of the two rate options after PV installation, but continue to select the least-cost rate prior to PV installation. This combination of assumptions results in the lowest value of bill savings possible, and thus helps to illustrate both the significance of our base-case assumption, as well as, more generally, the importance of proper rate selection for customers with net metered PV.

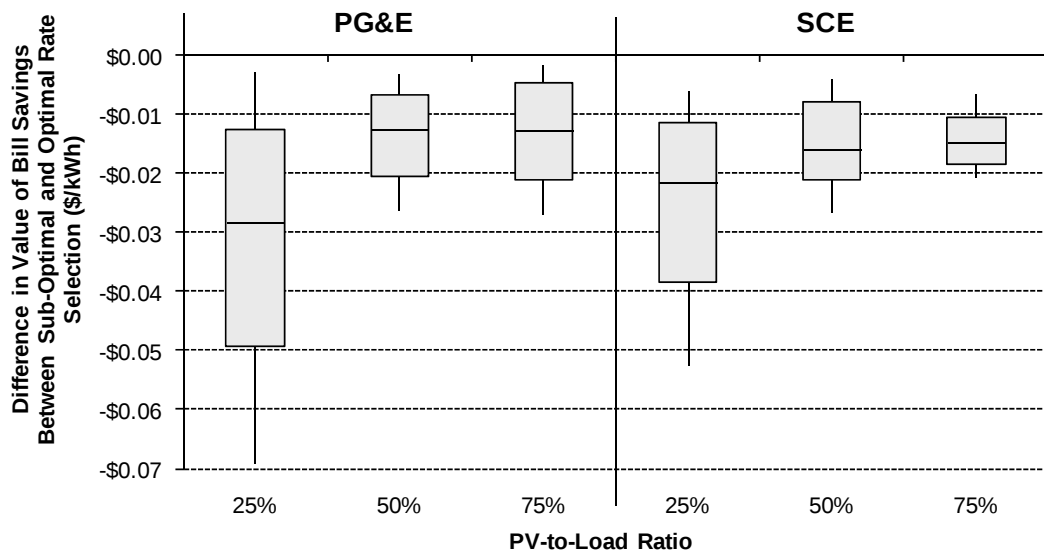


Figure 4. Distribution in the Effect of Sub-Optimal Rate Selection on the Value of Bill Savings. Box plots identify the 10th, 25th, 50th, 75th, and 90th percentile values.

For each customer, we calculated the *difference* between the value of the bill savings under the worst-case rate selection assumptions and under the least-cost (i.e., base-case) rate selection assumptions. These results are summarized in Figure 4, which shows the distribution in the difference between the bill savings in this scenario and in the base case, across customers and PV-to-load ratios. In general, the results indicate that sub-optimal rate selection leads to a reduction in bill savings of less than 10%, but can have a much greater impact for some customers at a low PV-to-load ratio. Among the PG&E

customers in our sample, the median loss in bill savings associated with sub-optimal rate choice ranges from about \$0.013-\$0.028/kWh (6-11%) depending on the PV-to-load ratio. For SCE customers the median loss in bill savings ranges from about \$0.015-\$0.021/kWh (7-10%). However, at a low PV-to-load ratio, some customers – particularly those with an especially flat or peaky load profile who would tend to be much better off on one rate vs. the other – may experience a much greater loss in bill savings as a result of sub-optimal rate selection. For example, at a 25% PV-to-load ratio, 25% of the PG&E customers in our sample would experience a loss in bill savings of at least \$0.049/kWh or 23%, and 25% of the SCE customers would experience a loss in bill savings of at least \$0.039/kWh or 17%, as a result of sub-optimal rate selection. At higher PV-to-load ratios, sub-optimal rate selection becomes less important for these customers, primarily because net consumption, and thus the customers' exposure to retail rates, is lower.

4.4. Sensitivity Analyses: Alternate PV Panel Orientations

Throughout most of our analysis, we assume that PV systems are oriented south-facing at a 25° tilt. To test the effect of alternate PV orientations, we also calculated the value of the bill savings for PV systems at two alternate orientations: (1) panels facing at an azimuth of 240° (approximately west-southwest) with a 25° tilt, and (2) panels mounted flat, i.e., with zero tilt.

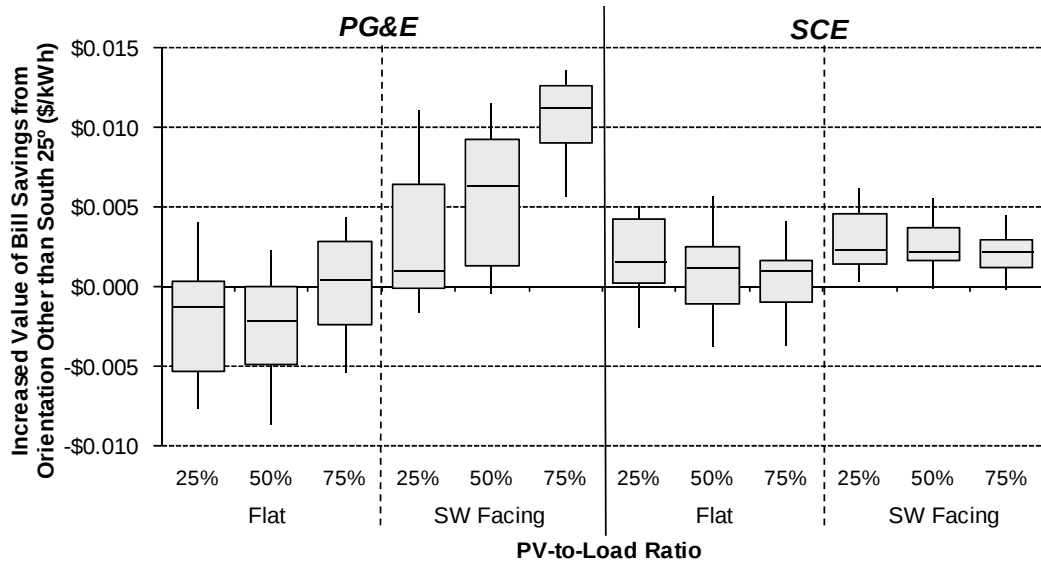


Figure 5. Difference in Bill Savings between Alternate and Base-Case PV Orientations. Box plots identify the 10th, 25th, 50th, 75th, and 90th percentile values.

For each customer, we calculated the *difference* between the value of the bill savings with each alternate PV orientation and the base case orientation. These results are summarized in Figure 5, which shows the distribution in the difference in bill savings across customers, for each PV-to-load ratios. These results show that, between the base case panel orientation and each alternate orientation, the per-kWh value of bill savings generally differs by less than \$0.01/kWh, or 5%. For most PG&E customers, the flat orientation results in slightly lower bill savings per kWh than the base-case orientation, particularly at low PV-to-load ratios, while the southwest-facing system generally results in higher per-kWh bill savings than the base-case orientation. For SCE customers, both alternate orientations generally yield higher per-kWh bill savings than the base-case orientation. Differences in per-kWh bill savings relative to the base-case PV panel orientation are a function of the distribution in PV production across TOU periods. Specifically, the per-kWh bill savings are greater if a greater percentage of total PV generation occurs during relatively high-priced TOU periods.

Importantly, however, these comparisons do not indicate which orientation would produce a greater *absolute* level of bill savings (in terms of the total dollar reduction in annual utility bills), as the quantity of PV electricity production also varies among orientations. These effects are, in fact, more significant than the change in the per-kWh value of bill savings across the three PV panel orientations. Thus, for most customers, the absolute dollar amount of bill savings would be lower under the alternative PV panel orientations than under the base-case orientation, irrespective of the negative or positive changes in the per-kWh value of bill savings. In particular, across all customers in our sample, the absolute dollar amount of bill savings would be 9-12% lower under than the alternative PV orientation compared to the base-case orientation.

5. Comparison of Bill Savings between Net Metering and Alternative PV Compensation Mechanisms

In this section, we compare the bill savings between net metering and each of three alternative compensation mechanisms described in section 3.4: a full MPR-based feed-in tariff, MPR-based hourly netting, and MPR-base monthly netting.

5.1. Hourly and Monthly Net Excess PV Production

Under the hourly and monthly netting options, only a portion of PV production – the hourly or monthly net excess PV generation, respectively – is compensated at MPR-based prices rather than at the retail rate. Figure 6 shows the portion of annual PV production subject to MPR-based prices (i.e., total annual net excess generation as a percentage of total annual generation), based on all PG&E and SCE customers in the sample combined. Net excess generation is computed in three different ways: on an hourly basis (for the hourly netting option), a monthly TOU-period basis (for customers on a TOU rate under the monthly netting option), or a simple monthly basis (for customers on a flat rate under the monthly netting option).

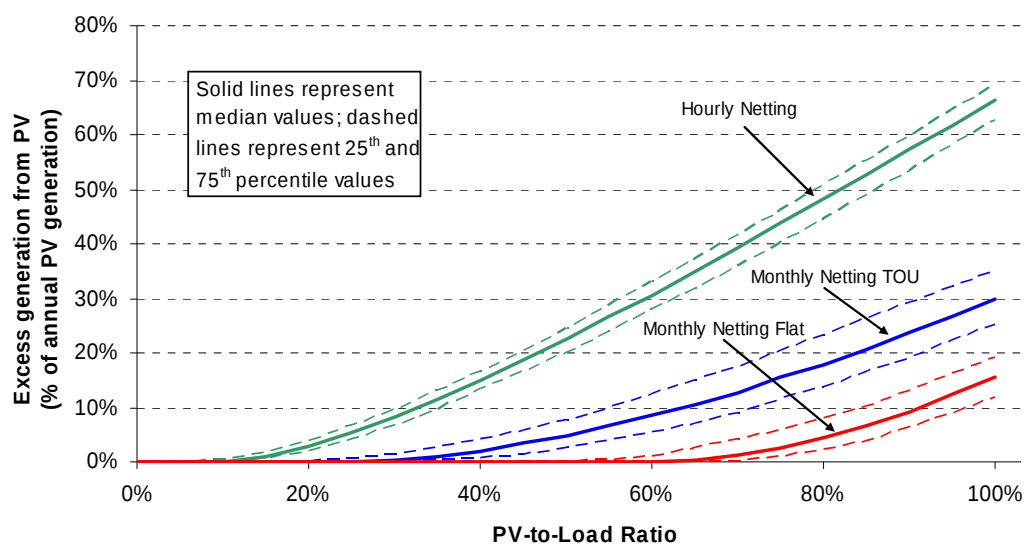


Figure 6. Annual Net Excess PV Generation under Hourly and Monthly Netting Options

As to be expected, annual net excess PV generation as a percentage of total generation rises with the PV-to-load ratio, and is greatest under hourly netting and least under simple monthly netting for customers on a flat rate. With hourly netting, net excess generation begins to occur at a PV-to-load ratio of roughly 10% (in the median case), rising to 44% at a 75% PV-to-load ratio. For monthly-TOU netting, net excess generation begins to occur at PV-to-load ratios greater than about 30%, reaching 15% of total PV generation at a 75% PV-to-load ratio. Finally, when calculated on a simple monthly basis for customers on a flat rate, net excess generation occurs only at PV-to-load ratios greater than about 65%, reaching just 3% of total annual PV generation at a 75% PV-to-load ratio. Net excess under monthly netting with the flat rate is lower than with the TOU rate, because with the flat rate, net consumption in any hour can be offset by net generation in any other hour of the month, whereas under the TOU rate, net consumption can only be offset by net generation occurring within the same TOU period. From this analysis, we can see that, with monthly netting, a relatively small portion of PV generation is compensated in a different manner than under net metering.

5.2. Bill Savings under Alternate Compensation Mechanisms

Figure 7 presents the distribution, across customers in our sample, in the value of the bill savings under the three alternative compensation mechanisms. As shown, under the full MPR-based feed-in tariff, the median value of the bill savings from PV (recall that, for this analysis, we are treating explicit payments for PV generation as financially equivalent to bill credits) is approximately \$0.12/kWh for the PG&E customers in the sample, and \$0.13/kWh for the SCE customers. There is effectively no variation across customers or across PV-to-load ratios, given that the distribution in PV production across MPR TOD periods is relatively invariant across customers.

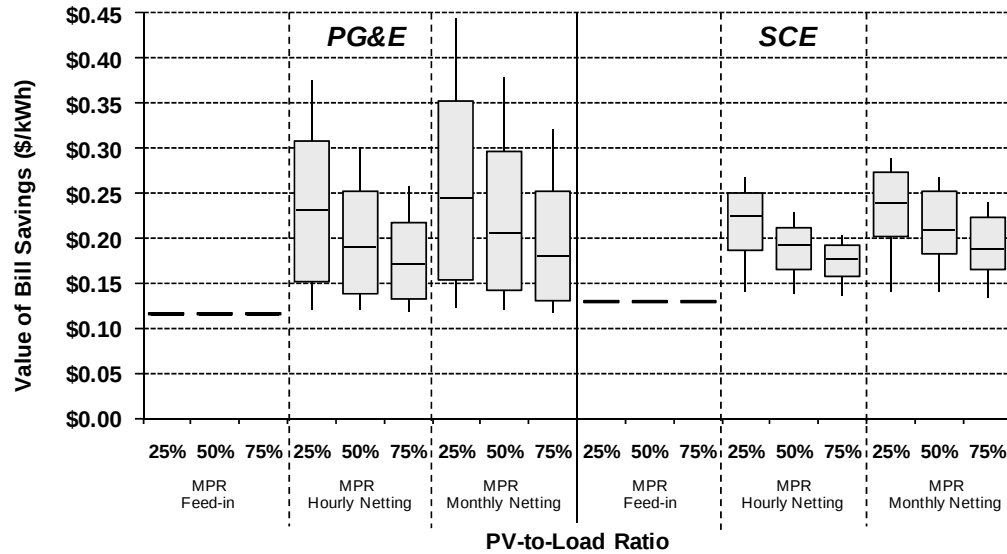


Figure 7. Bill Savings for Alternative PV Compensation Mechanisms and Net Metering. Box plots identify the 10th, 25th, 50th, 75th, and 90th percentile values.

Under the hourly netting option, the bill savings are significantly greater and more varied across customers than under the full MPR-based feed-in tariff. Under hourly netting, the total bill savings for any individual customer is equal to the sum of the bill savings from offsetting hourly consumption at retail prices and the bill credits for hourly net excess generation as compensated at the applicable MPR rate. The median bill savings for the PG&E customers in the sample is approximately \$0.23/kWh at a 25% PV-to-load ratio, declining to \$0.17/kWh at a 75% PV-to-load ratio. For SCE customers, the median bill savings ranges from \$0.23/kWh at a 25% PV-to-load ratio to \$0.18/kWh at a 75% PV-to-load ratio. The variation across customers is associated primarily with the portion of the bill savings derived from directly offsetting hourly customer usage.

Finally, under the monthly netting option, the bill savings are the highest among the three alternatives considered, and the distribution has a notably wider upper tail than that for the hourly netting option. Across the PV-to-load ratios shown, the median bill

savings ranges from \$0.23/kWh to \$0.18/kWh for the PG&E customers in the sample, and from \$0.24/kWh to \$0.19/kWh for the SCE customers.

5.3. Reduction in Bill Savings Relative to Net Metering

Figure 8 compares the value of the bill savings between each alternative compensation mechanism and net metering in terms of the *difference* in the bill savings; as such, negative values indicate that the bill savings under a particular alternative are lower than under net metering.

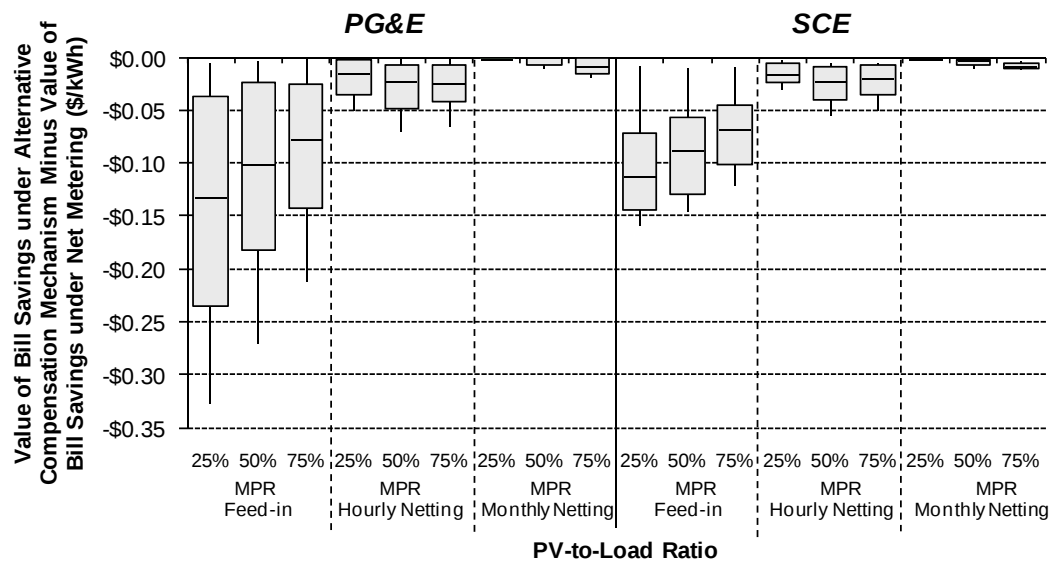


Figure 8. Difference in Bill Savings between Alternative PV Compensation Mechanisms and Net Metering. Box plots identify the 10th, 25th, 50th, 75th, and 90th percentile values.

Focusing first on the full MPR-based feed-in tariff, it is evident that most would receive substantially lower bill savings than under net metering, and the reduction in bill savings is greatest for high-usage customers (especially high-usage PG&E customers), who receive the largest bill savings under net metering. Among the PG&E customers in the sample, the median reduction in bill savings under the MPR-based feed-in tariff, relative to net metering, ranges from \$0.08-\$0.13/kWh (a 40%-54% reduction) across the PV-to-load ratios examined. For the quartile of PG&E customers with the highest usage,

however, the reduction in bill savings exceeds \$0.14-\$0.23/kWh (55%-67%) across the PV-to-load ratios. Among the SCE customers in the sample, the median reduction in bill savings under the MPR-based feed-in tariff, relative to net metering, ranges from \$0.07-\$0.11/kWh (34%-46%) across the PV-to-load ratios. The difference in bill savings between the MPR-based feed-in tariff and net metering is less for SCE than for PG&E, primarily because the bill savings under net metering are generally lower for the SCE customers than for the PG&E customers, particularly for high-usage customers. For a customer with PV to be indifferent between the full MPR-based feed-in tariff and net metering, the average price paid for PV generation under the feed-in tariff would therefore need to be higher than the average MPR-based price by an amount equal to the difference in the value of bill savings between the two options. For the median PG&E customer in our sample, the feed-in tariff price would therefore need to be \$0.13/kWh higher than the average MPR-based price at a 25% PV-to-load ratio and \$0.08/kWh higher at a 75% PV-to-load ratio. Similarly, for the median SCE customer in our sample, the feed-in tariff price would need to be \$0.11/kWh higher than the average MPR-based price at a 25% PV-to-load ratio and \$0.07/kWh higher at a 75% PV-to-load ratio. These values effectively represent the size of the “add-on” that would need to be included in the price paid for each kWh of PV generation under the feed-in tariff, in order for the median customer to be indifferent between the feed-in tariff and net metering.

Under the hourly netting option, the customers in our data sample would generally experience a reduction in bill savings relative to net metering, but the difference is significantly less than with the full MPR-based feed-in tariff. This is simply a consequence of the fact that, under the full MPR-based feed-in tariff, the entirety of the PV generation is compensated at the MPR rate (which is well below retail rates),

whereas under hourly netting, only the hourly net excess generation is compensated at the MPR rate. Thus, among the PG&E customers in the sample, the median reduction in bill savings relative to net metering is \$0.015/kWh (or about a 6% reduction in bill savings) at a 25% PV-to-load ratio, increasing to a \$0.024/kWh (or 12%) reduction at a 75% PV-to-load ratio. For the SCE customers, the median reduction in bill savings ranges from \$0.016/kWh (6%) to \$0.021/kWh (11%) over this range in PV-to-load ratios. Furthermore, unlike the full MPR-based feed-in tariff, the reduction in bill savings is not significantly greater for high-usage customers than for other customers in the sample, as demonstrated by the narrower distribution for hourly netting, as shown in Figure 8.

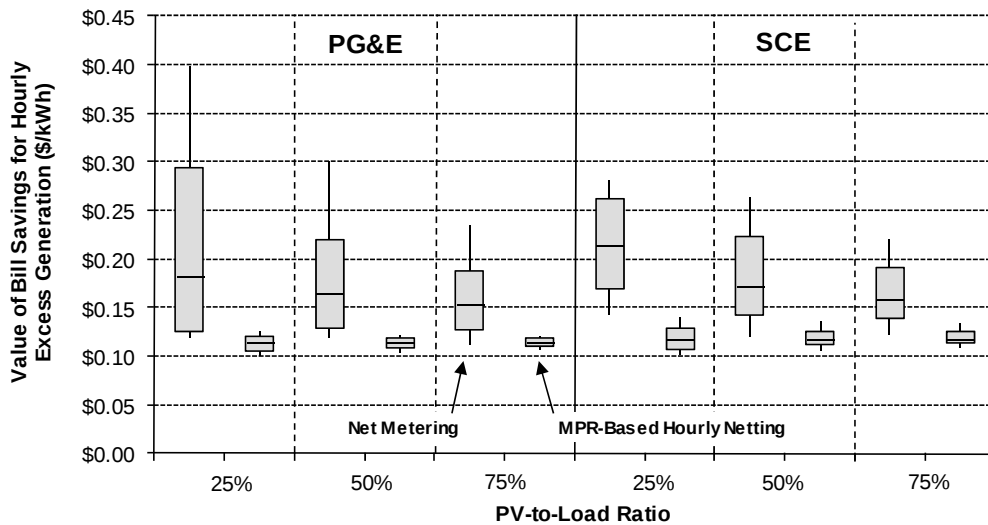


Figure 9. Comparison of Bill Credits for Hourly Excess Generation under Net Metering and MPR-Based Hourly Netting. Box plots identify the 10th, 25th, 50th, 75th, and 90th percentile values.

The difference in bill savings between net metering and MPR-based hourly netting derives specifically from the difference in the value of the bill credits provided for hourly excess generation, as shown in Figure 9. Under MPR-based hourly netting, the median value of the bill credits for hourly excess generation is about \$0.12/kWh across all PV-to-load ratios and for the customers of both utilities in our sample. In

comparison, the median value of the bill credits for hourly excess generation under net metering ranges from \$0.15-\$0.18/kWh for the PG&E customers, and from \$0.16-\$0.21/kWh for the SCE customers in the sample, across the three PV-to-load ratios.⁴ Higher prices for hourly net excess generation would therefore be required for most customers within our sample to be indifferent between hourly netting and net metering. Among PG&E customers in our sample, the price for hourly net excess generation would, in the median case, need to be increased above the current average MPR-based price by approximately \$0.07/kWh at a 25% PV-to-load ratio and \$0.04/kWh at a 75% PV-to-load ratio. Similarly, for the SCE customers in our sample, the price for hourly net excess generation would, in the median case, need to be increased above the current average MPR-based price by approximately \$0.09/kWh at a 25% PV-to-load ratio and \$0.04/kWh at a 75% PV-to-load ratio.

Last, as shown in Figure 8, the value of the bill savings under the MPR-based monthly netting option is only marginally different than under net metering. Specifically, the reduction in bill savings relative to net metering is zero (or approximately zero) at low PV-to-load ratios, and slightly greater at higher PV-to-load ratios (i.e., a median loss of less than \$0.01/kWh at 75% PV-to-load ratio, for both the PG&E and SCE customers in the sample). The difference between the value of the bill savings under net metering and under monthly netting is small for two reasons. First, and most obviously, the portion of PV generation that is compensated differently between the two options is quite small. Second, under net metering, monthly excess PV production is effectively credited at Tier 1 prices, which differ only slightly from the MPR-based prices.

6. Discussion and Conclusions

Net metering, in combination with other policy support mechanisms, has been instrumental in jump-starting the market for distributed PV in California and elsewhere in the U.S. One inherent feature of net metering is that the bill savings are dependent on the underlying retail rate structure. Understanding the manner and degree to which retail rate design affects the economics of net metered PV, and the relative value of net metering compared to other potential compensation mechanisms, is therefore critical for policymakers and utilities seeking to support the deployment of distributed PV.

Our analysis, based on the specific retail rates and net metering rules offered by PG&E and SCE, and on a sample of residential customers in the two utilities' service territories, yields the following key findings regarding the impact of retail rate design on the economics of net metered PV:

- Inclining block rates, such as those offered by PG&E and SCE, provide differentially greater support for PV adoption among high usage customers. In the case of PG&E and SCE, this dynamic is particularly pronounced, given the utilities' particularly steep usage tiers.
- Inclining block rates also yield diminishing returns to scale in terms of the bill savings per kWh of PV generation, which may encourage customers to install PV systems that meet a small portion of their overall load.
- The relative attractiveness of time-of-use (TOU) pricing for customers with net metered-PV is mixed and depends highly on what alternative rate structures are available, the characteristics of the customer load profile, and the size of the PV system relative to the customer's load. With respect to the latter, our analysis shows that, if the PV system is sized to meet only a small fraction of the customer's load, TOU rates may yield lower bill savings than a non-time-differentiated rate.

Beyond the specific findings noted above, the analysis presented here illustrates more generally the extent to which the net metering can produce substantial and unintended differences in bill savings across customers. Under the retail rate designs in our analysis, the bill savings from net-metered PV varies by a factor of 4-5 across the PG&E customers in our sample and by a factor 2-3 across the SCE customers, depending on the customer's usage level and the relative size of the PV system.

Though this level of variation in bill savings across customers and PV system sizes is relatively unique to California, it highlights several significant policy issues and tradeoffs inherent in net metering. In the early stages of market development, variation in bill savings across customers may serve a useful purpose by providing relatively high levels of compensation for a sub-set of customers and thereby fostering early adoption. In the long-run, however, large differences in the compensation provided for distributed PV across customers may be more problematic. First, from a social welfare perspective, the *variation* in bill savings occurring under the particular net metering and retail rates currently offered by PG&E and SCE arguably has little or no economic justification – that is, a PV system installed by a high-usage customer does not provide higher value to society than a PV system installed by a low-usage customer, nor does a kWh produced by a small distributed PV system necessarily provide higher value than one produced by a larger system.⁵ Second, the degree of variability across customers observed for the two utilities may introduce complexity and uncertainty for customers considering a potential investment in distributed PV. Many residential customers may not possess the analytical know-how, for example, let alone the necessary data, to accurately forecast the bill savings that they would receive under the current set of residential retail rates and net metering rules offered by the two utilities. Perhaps as important, retail rate structures are subject to change over the life of a PV system, introducing further

uncertainty for a customer considering a long-term PV investment. Of course, any alternative to net metering may also entail complexity and uncertainty for the customer and, in the end, the relative levels of complexity and uncertainty and the implications therein must be weighed against one another.

One potential alternative to net metering is to simply compensate all distributed PV electricity production under a feed-in tariff. Such an approach would eliminate much of the variation in bill savings that occurs under net metering. Our analysis, however, indicates that, if the price of the feed-in tariff were based on California's Market Price Referent (MPR), which is intended to represent the long-run wholesale market price of electricity, the value of the bill savings would be significantly eroded for most PG&E and SCE customers. Enabling continued deployment of distributed PV in California would therefore likely require a feed-in tariff with prices well above the current MPR. Increasing the feed-in tariff price to account for avoided T&D costs and reduced line losses would reduce, but likely would not eliminate, the erosion in bill savings that would occur under the MPR-based feed-in tariff.

Alternatively, an argument could be made that PV installed on the customer-side of the meter should not be treated fundamentally different from energy efficiency upgrades installed by the customer, and that distributed PV production should therefore be able to offset up to 100% of (hourly) customer usage, but any excess PV production would be compensated at a price reflective of avoided costs. Our analysis indicates that, even at relatively high PV-to-load ratios, such an approach would not significantly erode the value of the bill savings for PG&E and SCE customers, provided that the hourly net excess PV generation is compensated at a price equal to or greater than the MPR. At the same time, however, this type of compensation mechanism would not fundamentally mitigate the variability and uncertainty in bill savings under net metering, given that

most of the PV generation would continue to be used to offset customer usage, and thus the compensation provided for distributed PV generation would continue to largely be based on the underlying retail rate structure.

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¹ As of November 2010, 43 states and Washington DC required some or all utilities to offer net metering, and utilities in 3 additional states offered net metering voluntarily (DSIRE 2010). Some states in Canada and Australia also offer net metering.

² We note that the customer economics of PV is just one of many issues and trade-offs that policy makers and state utility regulators consider with respect to rate design, net metering, and policies for supporting solar deployment.

³ A recent law passed in California, Assembly Bill (AB) 920, alters this element of the net metering rules by requiring utilities to offer customers the choice either to receive compensation for net surplus electricity at the end of the year or to roll forward the net surplus electricity to be used as a credit against future electricity consumption. As of the writing of this article, revised tariffs implementing AB 920 had not yet been approved by the California Public Utilities Commission, and therefore the changes required by AB 920 are not reflected in our analysis.

⁴ In comparison, the recent E3 net metering cost-effectiveness evaluation (Energy and Environmental Economics 2010) reports that the average value of the bill credits provided for hourly excess generation under net metering is \$0.22/kWh for the population of net metered PG&E customers and \$0.16/kWh for SCE customers. These average values differ from the median values calculated for customers in our sample for a number of reasons: all else being equal, the average bill credit will generally be higher than the median value; the customers in our sample are smaller, on average; and our analysis assumes that customers choose the least-cost rate option, whereas the E3 study relies on the actual rate choice of each customer.

⁵ Of course, concerns about the societal justification of the current rate structure in California go well beyond the bill savings value of PV, and the variation in the bill savings value for PV under net metering applies more-or-less equally to the bill savings value of customer-driven energy efficiency investments.

Appendix A

PG&E and SCE both offer residential customers the choice between a non-time-differentiated (i.e., “flat”) rate and a time-of-use (TOU) rate. The utilities’ flat rates are “inclining block” rates with five usage tiers and increasing volumetric charges for usage within each successive tier. The lowest tier is the baseline allotment, which varies according to the baseline region in which the customer is located and is designed to cover 50-60% of the average electricity consumption in the region. The other four tiers are defined as percentages of the baseline: specifically, Tier 2 is 100-130% of the baseline, Tier 3 is 130-200%, Tier 4 is 200-300%, and Tier 5 is greater than 300%. For example, if the baseline quantity for a customer were 100 kWh and her monthly consumption were 250 kWh, then she would be charged 100 kWh at the Tier 1 rate, 30 kWh at the Tier 2 rate, 70 kWh at the Tier 3 rate, and 50 kWh at the Tier 4 rate; her marginal rate would be the Tier 4 rate.

Under the utilities’ residential TOU rates, volumetric charges vary according to both the season (summer vs. winter) and the time of day (see Table 1), with either two or three TOU periods during each day, depending on the utility and the season. PG&E’s residential TOU rate is tiered, with the same five usage tiers within each TOU period as are used on the utility’s flat rate. Customers on the TOU rate are thus assigned a baseline allotment for each TOU period, and usage within each TOU period is charged according to the tier within which it falls. SCE’s residential TOU rate is also tiered, though it only has two tier levels, with Tier 1 corresponding to consumption up to 130% of the baseline level and Tier 2 corresponding to all consumption over that level.

Table 1. TOU Period Definitions

Season*	TOU Period	PG&E	SCE
Summer	Peak	M-F 1pm-7pm	M-F 10am-6pm
	Part-peak	M-F 10am-1pm, 7pm-9pm Sat-Sun 5pm-8pm	n/a
	Off-peak**	M-F 12am-10am, 9pm-12am Sat-Sun 12am-5pm, 8pm-12am	M-F 12am-10am, 6pm-12am Sat-Sun all day
Winter	Peak	n/a	M-F 10am-6pm
	Part-peak	M-F 5pm-8pm	n/a
	Off-peak**	M-F 12am-5pm, 8pm-12am Sat-Sun all day	M-F 12am-10am, 6pm-12am Sat-Sun all day

* For PG&E, Winter is November-April, and Summer is May-October. For SCE, Winter is October-May, and Summer is June-September.

** Holidays are treated as off-peak, regardless of time or day of week.

PV generation correlates reasonably well with the higher priced TOU periods. Roughly 23% and 24% of annual PV electricity production is generated during the high-priced summer peak periods of PG&E and SCE, respectively. PV electricity production is significantly more-concentrated during the summer peak period than is customer usage in our sample, with 9.4% of PG&E customer usage and 9.8% of SCE customer usage occurring within each utility's respective summer peak period.

The MPR has several elements. The “baseload” MPR price, which is based on the long-term cost of a CCGT, is updated annually and varies according to the year in which the renewable energy project enters commercial operation and the contract length (in this paper, we used the approved 2009 baseload MPR rate for a 20-year contract with deliveries beginning in 2010, equal to \$0.09674). To establish the MPR price for a specific renewable energy generator or contract, the baseload MPR price is adjusted according to the Time-of-Delivery (TOD) period within which electricity is generated, by multiplying the baseload MPR rate by the utility-specific TOD adjustment factor.

Thus, similar to the utilities' retail TOU rates, the MPR TOD adjustment factors provide higher levels of compensation during summer afternoon hours than at other times, although the time periods and price spread between time periods differ between the retail TOU rates and the MPR TOD factors. The total compensation for excess PV in our MPR-based scenarios is calculated by summing total generation within each TOD period multiplied by the appropriate MPR rate and TOD factor.

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