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The Impact of Retail Rate Structures on the Economics of Commercial Photovoltaic Systems in California

Ryan Wiser, Andrew Mills, Galen Barbose, and William Golove

Environmental Energy Technologies Division

July 2007

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Abstract

To achieve a sizable and self-sustaining market for grid-connected, customer-sited photovoltaic (PV) systems, solar will likely need to be competitive with retail electricity rates. In this report, we examine the impact of retail rate design on the economic value of commercial PV systems in California. Using 15-minute interval building load and PV production data from 24 actual commercial PV installations, we compare the value of the bill savings across 20 commercial-customer retail rates currently offered in the state. We find that the specifics of the rate structure, combined with the characteristics of the customer's underlying load and the size of the PV system, can have a substantial impact on the customer-economics of commercial PV systems.

Key conclusions for policymakers that emerge from our analysis are as follows:

- **Rate design is fundamental to the economics of commercial PV.** The rate-reduction value of PV for our sample of commercial customers, considering all available retail tariffs, ranges from $0.05/kWh to $0.24/kWh, reflecting differences in rate structures, the revenue requirements of the various utilities, the size of the PV system relative to building load, and customer load shapes. For the average customer in our sample, differences in rate structure, alone, alter the value of PV by 25% to 75%, depending on the size of the PV system relative to building load.

- **TOU-based energy-focused rates can provide substantial value to many PV customers.** Retail rates that wrap all or most utility cost recovery needs into time-of-use (TOU)-based volumetric energy rates, and which exclude or limit demand-based charges, provide the most value to PV systems across a wide variety of circumstances. Expanding the availability of such rates will increase the value of many commercial PV systems.

- **Offering commercial customers a variety of rate options would be of value to PV.** Despite the advantages of energy-focused rates for PV, *requiring* the use of these tariffs would disadvantage some commercial PV installations. In particular, for PV systems that serve less than 25-50% of annual customer load, the characteristics of the customer's underlying load profile often determine the most favorable rate structure, and energy-focused rate structures may not be ideal for many commercial-customer load shapes. Regulators that wish to establish rates that are beneficial to a range of PV applications should therefore consider allowing customers to choose from among a number of different rate structures.

- **Eliminating net metering can significantly degrade the economics of PV systems that serve a large percentage of building load.** Under the assumptions stipulated in this report, we find that an elimination of net metering could, in some circumstances, result in more than a 25% loss in the rate-reduction value of commercial PV. As long as annual solar output is less than roughly 25% of customer load and excess PV production can be sold to the local utility at a rate above $0.05/kWh, however, elimination of net metering is found to rarely result in a financial loss of greater than 5% of the rate-reduction value of PV.

More detailed conclusions on the rate-reduction value of commercial PV include:

- **Commercial PV systems can sometimes greatly reduce demand charges**. Though energy-focused retail rates often offer the greatest rate reduction value, commercial PV installations can generate significant reductions in demand charges, in some cases constituting 10-50% of the total rate savings derived from PV installations. These savings, however, depend highly on the size of the PV system relative to building load, on the customer's load shape, and on the design of the demand charge itself.

- **The value of demand charge reductions declines with PV system size.** At high levels of PV penetration, the value of PV-induced demand charge savings on a $/kWh basis can drop substantially. As a result, the rate-reduction value of PV can decline by up to one-half when a PV system meets 75% rather than 2% of total building load. Thus, for rates with significant demand charges, the drop in demand charge savings dramatically reduces the overall rate-reduction value of PV as system size increases relative to customer load.

- **The ability of PV to offset demand charges is highly customer-specific.** Customers with loads that peak in the afternoon are often able to receive significant demand charge savings across a wide variety of circumstances, at least at lower levels of PV output relative to building load. In contrast, facilities with flat or inverted load profiles will often not earn much demand charge reduction value, regardless of PV system size.

- **The type of demand charge can impact the ability of PV to offer savings.** Time-of-day (TOD)-based demand charges are found to be more favorable to PV under a broad range of customer load shapes than are those based on monthly or annual peak customer demand.

- **The type and design of energy-charges has an important impact on PV value.** TOU-based energy charges with a high spread between peak and off-peak prices are found to offer greater value to commercial PV than rates with seasonal or flat energy charges. In particular, TOU-based energy charges with a large price spread between peak and off-peak prices are shown to offer 20% greater energy charge savings compared to seasonal or flat energy charges.

- **Differences in temporal PV production profiles have a relatively modest impact on PV value.** We find that the specific temporal profile of PV production, at least among the 24 systems in our sample, has an impact on the value of PV of less than $0.01/kWh in most instances for both energy and demand charges. This suggests that, when one conducts customer-specific analysis, it may not be essential to use a highly-tuned estimate of the site-specific PV production profile for the purpose of deriving the $/kWh rate reduction value.

In summary, our findings suggest that choices made by utility regulators in establishing or revising retail rates can have a profound impact on the future viability of customer-sited commercial PV markets.

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Acronyms and Abbreviations

C&I	commercial & industrial
COE	cost of electricity
CPUC	California Public Utilities Commission
ELCC	Effective Load Carrying Capacity
IOU	Investor Owned Utility
LADWP	Los Angeles Department of Water & Power
PG&E	Pacific Gas & Electric
PV	photovoltaic
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SMUD	Sacramento Municipal Utility District
TOD	time of day
TOU	time of use
VPV	value of PV

Executive Summary

Introduction

The solar power market is growing at a quickening pace, fueled by an array of national and local initiatives and policies aimed at improving the value proposition of customer-sited photovoltaic (PV) systems. Though these policies take many forms, they commonly include up-front capital cost rebates or ongoing production incentives, supplemented by net metering requirements to ensure that customer-sited PV systems offset the full retail rate of the customer-hosts.

Somewhat less recognized is the role of retail rate design, beyond net metering, on the customer-economics of grid-connected PV. Over the life of a PV system, utility bill savings represent a substantial portion of the overall economic value received by the customer.[1] At the same time, the design of retail electricity rates, particularly for commercial and industrial customers, can vary quite substantially. Understanding how specific differences in rate design affect the value of customer-sited PV is therefore essential to supporting the continued growth of this market.

The purpose of this study is to broadly examine the impact of rate design on the economic value of customer-sited PV for commercial customers. We focus, in particular, on 20 commercial and industrial electricity rates currently offered by the five largest electric utilities in California. We compute the annual electricity bill savings that would be realized on each of these rates by 24 actual commercial PV installations in California, using 15-minute interval building load and PV production data from those sites. We then compare the calculated bill savings across rate schedules and customer sites, and isolate differences related specifically to rate design, as well as differences related to other factors, including: the average cost of electricity on each rate, the customer load shape, the PV production profile, and the size of the PV system relative to customer load. After isolating the impact of rate design, as a whole, we then examine differences in the value of PV associated with specific rate design elements, including the design of both energy-based and demand-based charges.

Analytical Approach

For each combination of the 20 rate schedules and 24 PV/load datasets, we calculate the *pre-tax* value of the utility bill savings *per kWh generated*, according to the following expression:

$$Value\ of\ PV = \frac{Total\ Bill\ without\ PV - Total\ Bill\ with\ PV}{Annual\ PV\ Energy\ Production} \quad (\$/kWh)$$

Expressing the value of PV on a per kWh basis, rather than in absolute dollar terms, serves two purposes. First, it allows us to abstract from the specific size of the PV system, since it is a foregone conclusion that larger systems will generally produce larger absolute bill savings.

[1] State and federal financial incentives, and sales of renewable energy certificates, represent other possible monetary gains.

Second, commercial customers in California and elsewhere are increasingly choosing to finance their PV systems through Power Purchase Agreements, whereby the customer purchases the PV output from a third-party owner on a per kWh basis; expressing the value of PV in the same units more readily allows for a direct comparison between the financial costs and benefits of PV from the customer's perspective in this instance.

We calculate the value of PV using both the actual PV production data from our 24 customer sites, as well as adjusted PV production data that has been scaled up or down so that annual PV production is equal to specific percentages of the gross annual building consumption at the site. We refer to these percentage values as *PV penetration levels* and, in presenting our results, we focus primarily on PV penetration levels of 2% and 75% as representative boundary cases.

In general, we assume that customers remain on the same rate before and after the installation of a PV system, and that PV output is net metered according to the specific net metering rules of each utility. However, we also conduct separate analyses in which each of these assumptions is relaxed. In one alternate scenario, we calculate the value of PV under the assumption that customers choose the bill-minimizing rate before and after PV installation, from among each set of rates offered by a utility to a common class of customers (e.g., the set of rates offered by PG&E to customers with peak demands of 200-500 kW). This analysis helps to reveal which rate design feature(s) dominate in determining the optimal rate for customers with PV and also illustrates the value of offering multiple rate options to customers with PV. In another alternate scenario, we calculate the value of PV under the assumption that net metering is *not* available, in order to show the financial losses that commercial PV customers in California might bear if net metering were eliminated and replaced with an alternate compensatory structure.

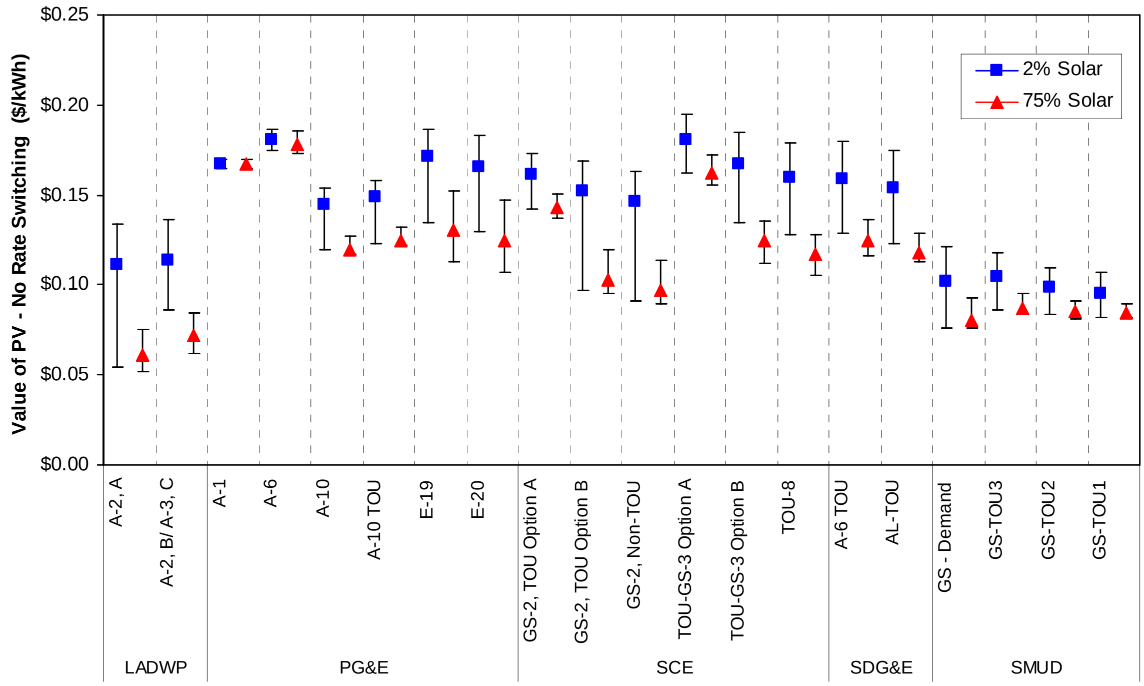
Key Findings

Value of Commercial PV in California with No Rate Switching

Figure ES-1 summarizes the value of commercial PV in California for each of the 20 retail rates in our sample, at 2% and 75% PV penetration levels. The central tick-marks in the figure represent median values across the 24 PV installations, while the error bands represent the $10^{th}/90^{th}$ percentile values among our 24-customer sample.

This figure and further results presented in the report support three basic observations:

- ***The value of PV varies widely across rates and customers.*** At 2% PV penetration, the median value of PV among the 24 customers varies by nearly a factor of two across the 20 rates in our sample, from \$0.10/kWh to \$0.18/kWh. At 75% PV penetration, the variation in median values is even greater, ranging from \$0.06/kWh to \$0.18/kWh. This variation reflects differences in both rate *structure* as well as rate *level* (i.e., some rate schedules simply have larger charges, separate from how those charges are structured). Considering customer characteristics, reflected in the percentile bands, leads to an even broader range of PV value, from \$0.05/kWh to \$0.24/kWh at 2% PV penetration.



Median value with error bars for 10th to 90th percentile range

Figure ES-1. Value of PV at Different Levels of Penetration, by Rate Structure (no rate switching)

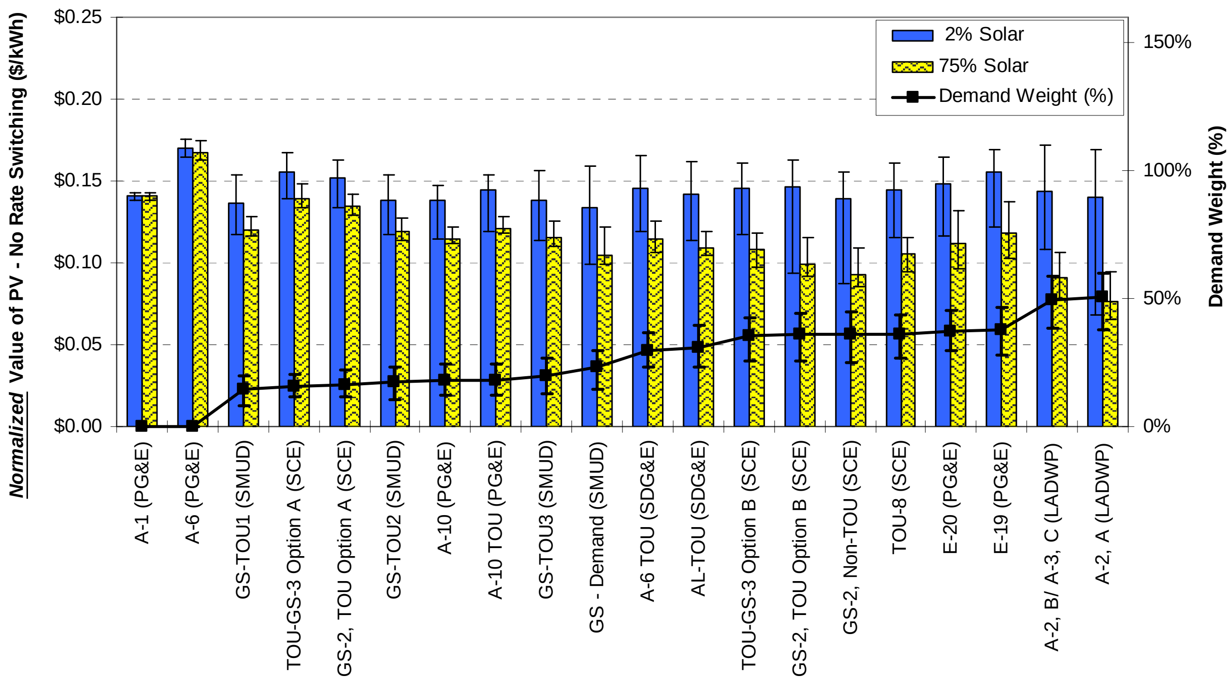
- ***Larger PV systems, relative to building load, tend to have a lower rate-reduction value than smaller systems, on a per-kWh basis.*** As PV systems are sized to provide increasing levels of annual facility load, the per-kWh value of those PV systems declines significantly on many rates. Overall, the median rate-reduction value of PV declines from $0.14/kWh to $0.12/kWh when PV penetration increases from 2% to 75%, a drop of approximately 20%. It is also evident, however, that the magnitude of this decline varies significantly among rates, with some rates seeing little to no decline in PV value.

- ***The shape of a customer's load profile can impact the rate-reduction value of PV.*** The spread between the upper and lower percentile bands – which are the result of variations in customer load profiles and PV production profiles – differs substantially across rates and tends to be wider at 2% PV penetration than at 75%. This indicates that the shape of the customer's load profile and (to a much lesser extent) the PV production profile may be much more important determinants of the value of PV for some rates than others, and more so at lower PV penetration levels.

Demand Charge Savings from Commercial PV with No Rate Switching

The observations noted above are driven, in large part, by the existence of demand charges. The relative size of demand-based charges, compared to energy-based charges, can have a sizable impact on the rate-reduction value of PV. This finding is powerfully illustrated by Figure ES-2, which presents the *normalized*[2] value of PV relative to a variable called the demand weight, which represents the proportion of total customer electric bills (pre-PV) that is made up of demand charges.

The figure shows that, when PV systems represent a small proportion of load, the existence of demand charges need not substantially degrade the value of PV. This is shown by the fact that, at 2% PV penetration, the normalized value of PV does not universally drop with increasing demand weight. In contrast, at 75% PV penetration, the normalized value of PV unmistakably drops as the relative magnitude of demand-based charges increase. The physical basis underlying this trend is that, at higher levels of PV penetration, the customer's maximum demand shifts to times when PV production is minimal or non-existent.



Median value with error bars for 10th to 90th percentile range

Figure ES-2. Impact of Demand Charges on the Overall Normalized Value of PV

Clearly, PV systems can provide significant demand-charge savings, but these savings diminish with system size. In fact, the decline in the overall rate-reduction value of PV at higher PV penetration rates is driven almost entirely by a decline in demand charge savings. At a 2% PV penetration level, for example, the median value of actual (not normalized) demand charge savings is as high as $0.05-$0.07/kWh for 8 of the 20 rates examined, in several cases comprising more than 50% of the total bill savings. At a 75% penetration level, however, the

[2] To isolate the impact of differences in rate structure, the value of PV for each customer-rate combination can be normalized to control for differences in the magnitude of charges on each rate. We calculate the normalized value of PV by first dividing the value of PV for each customer-rate combination by the median cost of electricity on that rate across all 24 customers, prior to PV installation. We then multiply this value by the median cost of electricity across all combinations of the 24 customers and 20 rates (again, without PV). It is important to note that it is the relative value of these normalized results that matters; the specific numerical values have no particular meaning.

median value of demand charge savings declines precipitously, amounting to, at most, \$0.01-\$0.02 per kWh generated. As a result, at high PV penetration rates, the value of PV is dominated by energy charge savings.

As shown in further detail in the report, other than PV penetration level, we find that two other factors substantially impact the ability of PV systems to reduce demand-based charges:

- ***Demand charge design:*** Demand charges can be differentiated from one another according to how customer demand is defined for the purposes of determining the charge. Among the rate schedules included in this report, three different measures of customer demand are used: *annual* (maximum demand over the preceding 12 months), *monthly* (maximum demand in the monthly billing period), and *time-of-day* (maximum demand in one or more time-of-day periods within the monthly billing period).[3] We generally find that demand reductions are much less variable, and greater in the median case, when demand charges are based on maximum demand during the summer peak TOD period. It is also quite clear, however, that the magnitude of those demand reductions is sensitive to the particular definition of the summer peak TOD period that is used. Specifically, demand reductions are greater and, at low penetration levels, much less variable across customers, the earlier the peak period ends. As the period extends further into evening hours, it becomes more likely that the customer's peak demand will occur in hours when its PV system is producing little or no energy.

- ***Customer load profile:*** For a given rate schedule and PV penetration level, savings on demand charges can vary substantially across customers, indicating that the specific characteristics of the customer's building load profile and/or PV production profile can be important determinants of the value of PV. We find that, regardless of the composition of the demand charges, customers with an afternoon peak load shape can receive substantial demand charge savings at low PV penetration levels, and modest but still meaningful savings at high PV penetration levels. In contrast, customers with flat or inverted load profiles earn essentially no demand charge savings on rates without TOD demand charges. On rates with a TOD charge, customers with flat or inverted load profiles may earn some modest amount of demand charge savings, but only at low PV penetration levels.[4]

Energy Charge Savings from Commercial PV with No Rate Switching

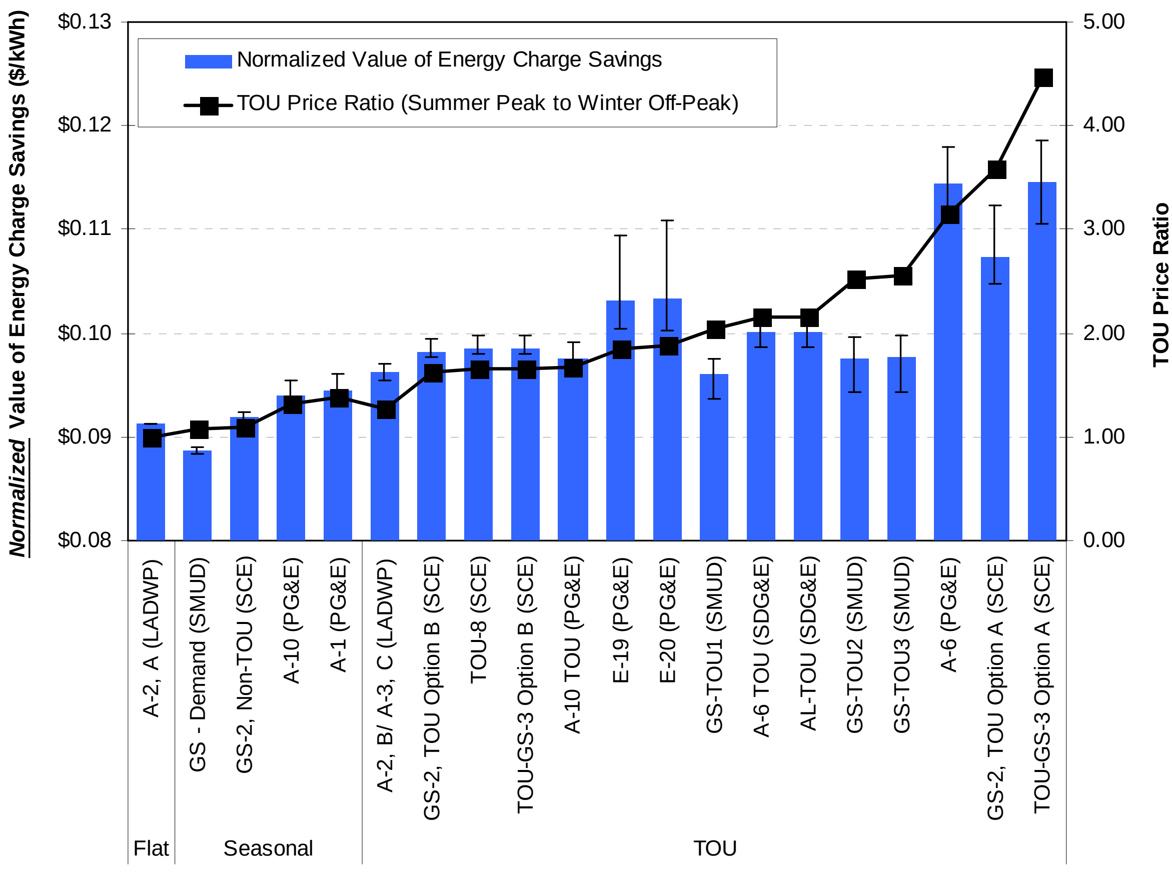
In contrast to demand charge savings, neither the level of PV penetration nor the customer's load shape exert much if any influence on PV-induced energy charge savings. Moreover, as with demand-based charges, we find that the specific temporal profile of PV production has a moderate impact on energy charge savings of less than \$0.01/kWh in most instances.

Just as the design of demand-based charges affects the rate-reduction value of PV, however, so too does the design of energy-based charges. In particular, we find that two design elements impact the degree to which commercial PV systems in California can offer energy charge

[3] Time-of-day (TOD) demand charges typically focus on the summer weekday afternoon TOD period, but may also include lesser charges for other TOD periods.
[4] Interestingly, we find that the specific shape of the PV production has a relatively modest effect on the value of demand charge savings.

savings: the basic type of energy charge (flat, seasonal, or TOU) and, for TOU-based charges, the spread between peak and off-peak prices.

Figure ES-3 presents the *normalized* value of energy charge savings for each rate, grouping the rates according to the type of energy charge used and listing the rates in order of increasing summer peak to winter off-peak price ratio. From visual inspection of this figure, we see that much of the variation in the normalized value of energy charge savings can be explained by these two rate design elements. In particular, TOU-based energy rates with relatively little spread between peak and off-peak prices offer approximately 5-10% greater energy charge savings than do rates with seasonal or flat energy charges, whereas those TOU rates with a much larger price spread offer more than 20% greater savings on energy charges than do flat or seasonal charges. The basic reason for these findings is that TOU rates provide a higher credit for PV production during summer afternoon periods, which is also when production tends to be greatest.



Median value with error bars for 10th to 90th percentile range

Figure ES-3. Summary of Rate Structure Impacts on Energy Charge Savings

Optimal Rate Selection

The analysis presented thus far assumes that customers are on the same rate before and after PV installation. In reality, however, customers often have a choice of rate options and can select the rate that minimizes their bill, both before and after PV installation.

When rate switching is allowed, we find that the impact of PV penetration diminishes somewhat. Specifically, without rate switching, increasing PV system size from 2% to 75% of customer load reduces the median normalized value of solar electricity by a full 20%. With the assumption that customers can choose among available commercial tariffs, however, the reduction in value with higher PV penetrations drops from 20% to13%.

We also find that, at low levels of PV penetration, customer load characteristics largely determine the optimal retail rate, and the existence of a PV system does not lead to widespread rate switching from the before-PV case. At higher levels of PV penetration, however, a substantial proportion of customers will be better off switching to an energy-focused "PV-friendly" rate; in other words, the customer's load profile is dominated by the existence of the PV system in optimal rate selection.

Of the rate schedules analyzed in this paper, three have been identified as "PV-friendly" primarily due to minimal or no demand charges: PG&E's A-6; SCE's GS-2, TOU Option A; and SCE's TOU-GS-3 Option A.[5] Depending on its peak demand, a customer may be able to choose between one of these "PV-friendly" rates and one or more other rate options (see Table ES-1). For each of the 24 customers in our dataset, we determined the optimal rate within each of the four rate groups identified in Table ES-1, across a range of PV penetration levels. Figure ES-4 presents these results, in terms of the percentage of customers for which each "PV-friendly" rate is optimal. At PV penetration levels greater than 50%, all or nearly all of the customers in our sample would minimize their utility bill by switching to the "PV-friendly" rate. At low PV penetration levels, however, these "PV-friendly" tariffs would not be optimal for many customers. As such, if energy-focused rates were required of *all* commercial PV systems, then many customers wishing to install smaller PV systems (relative to load) would be disadvantaged.

[5] Though PG&E's A-1 rate has no demand charges, it is not designated as "PV-friendly" in this report because other available rates are more attractive to all 24 of the customers in our sample, at all levels of PV penetration. LADWP similarly offers an otherwise "PV-friendly" rate with low demand charges (A-2, D), but that rate is not available with net-metering, making it very unattractive at high levels of PV penetration. As a result, that rate was not included in our analysis.

Table ES-1. Rate Options for Different Customer Classes

Rate Options

Utility	Customer Size	Rate Options Available
PG&E	<200 kW	PV-friendly: A-6 Other Rates: A-1; A-10; A-10 TOU; and E-19
	200-500 kW	PV-friendly: A-6 Other Rates: A-10 TOU and E-19
SCE	20-200 kW	PV-friendly: GS-2, TOU Option A Other Rates: GS-2, TOU Option B and GS-2, Non-TOU
	200-500 kW	PV-friendly: TOU-GS-3 Option A Other Rates: TOU-GS-3 Option B

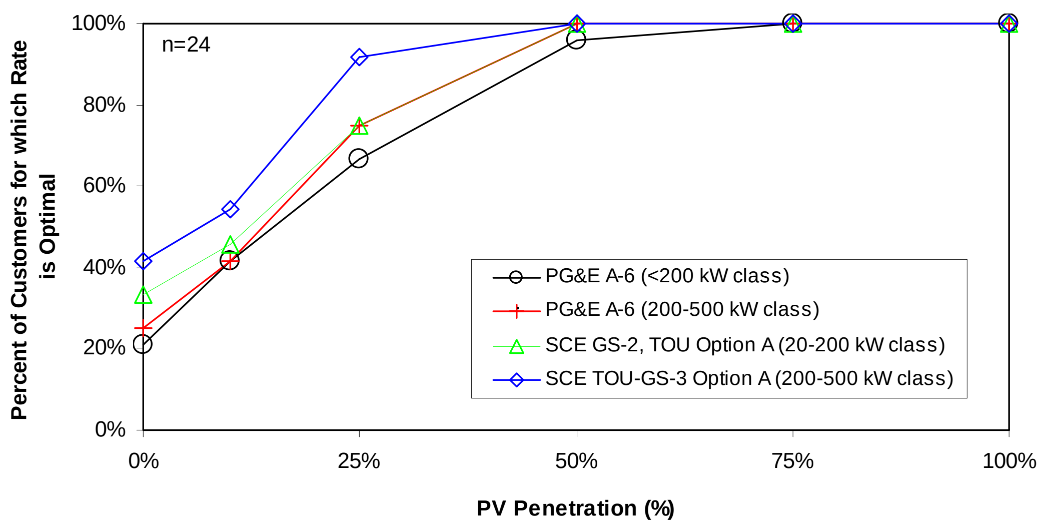


Figure ES-4. Customer Choice of Energy-Focused Rates at Varying Levels of PV Penetration

The Value of Net Metering

The analysis presented thus far has assumed that PV systems are net metered. To estimate the incremental value of net metering, we also calculate the value of PV without net metering, for each combination of customer and rate schedule.

Doing so first requires stipulating how PV output would be compensated in the absence of net metering. One potential compensatory scheme, which we analyze here, is where PV production in excess of the customer's load during any 15-minute interval is either uncompensated (i.e., "donated" to the utility) or sold to the local electric utility at some pre-specified sell-back rate. Just as with net metering, all PV production up to the customer's load during each 15-minute interval is assumed to be valued at the prevailing retail rate. The only difference is in the treatment of excess PV production, above the customer's load, during each 15-minute interval.

Figure ES-5 shows the loss of value without net metering across a range of PV penetration levels, under four different sell-back rates (including \$0.00/kWh, where excess generation in each 15 minute interval is donated to the utility). For each scenario, the figure shows the distribution of the loss of PV rate-reduction value (median and 10th/90th percentile values) across all combinations of rates and load/PV datasets.[6]

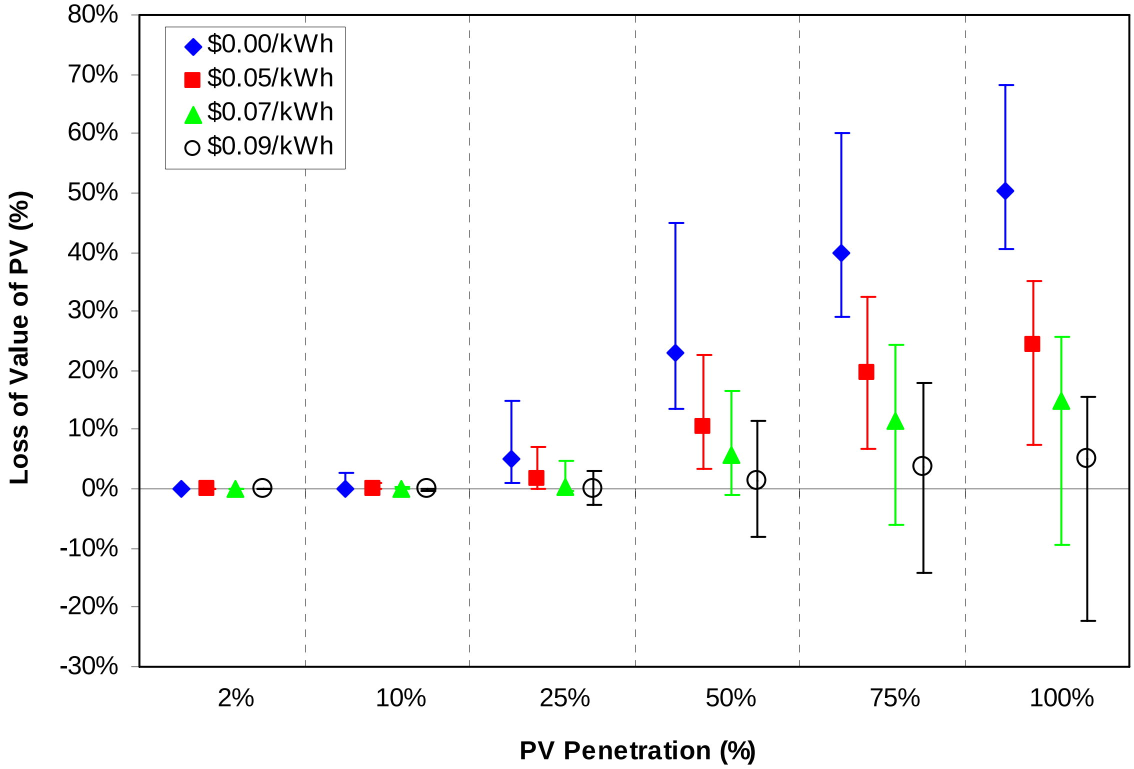


Figure ES-5. Loss of Value without Net Metering, Depending on the Sell-Back Rate for Net Excess Generation

Several key findings emerge from this figure and from further results presented in the body of the report.

- First, eliminating net metering can significantly degrade the economics of PV systems that serve a large percentage of building load. Under the assumptions stipulated in the report, we find that an elimination of net metering could, in some circumstances, result in more than a 25% loss in the rate-reduction value of commercial PV.
- Second, at PV penetration levels of less than 25%, net metering provides little incremental value to the customer, compared to the alternate compensatory structure described above. At

[6] The loss of value of PV without net metering is negative (that is, losing net metering is beneficial) in cases where the sell-back rate is greater than the value of PV with net metering.

low penetration levels, little to no net excess PV generation occurs over the course of the year, and therefore all or almost all of the PV production is valued at the full retail rate.[7]

- Third, not surprisingly, the loss of value without net metering is highly sensitive to the sell-back rate, with lower sell-back rates leading to greater losses.
- Fourth, as shown in the body of the report, the potential economic loss from eliminating net metering is greatest under what might be considered the most "PV-friendly" retail rates: those with low demand charges.
- Finally, customers with flat or inverted load shapes have more to lose from the elimination of net metering than do those customers with more typical afternoon peaks, assuming that the treatment of PV production in the absence of net metering is similar to what is posited here. Customers with load shapes that match PV production profiles depend less on net metering, and thus are able to host proportionately larger PV systems without experiencing significant erosion in value if net metering is eliminated.

Conclusions

As we show in this report, the importance of rate design for commercial PV systems goes well beyond the availability of net metering. Instead, the specifics of the rate structure, combined with the characteristics of the customer's underlying load and the size of the PV system, can have a substantial impact on the economics of customer-sited commercial PV systems.

By extension, choices made by utility regulators in establishing or revising retail rates can have a profound impact on the future viability of solar markets. Though regulators must consider a number of sometimes-conflicting objectives when designing and approving retail rates, one important step regulators might take to promote PV systems is to make available, on an *optional* basis, commercial rate schedules with: (1) low (or no) demand charges; (2) TOU-based energy charges that have a wide spread between peak and off-peak prices, and (3) a TOU peak period that ends during late afternoon hours. If demand-based charges are to be used, TOD-based demand charges are likely to be most favorable towards commercial PV installations.

Customers who plan to install PV systems (and retailers selling those systems) should evaluate the full set of rate options available. If the PV system is small relative to building load, the optimal rate may be one with sizable demand charges. In this case, the customer/retailer should not ignore potential demand charge savings when estimating bill savings, especially for customers whose load shape has an afternoon peak. Given the sensitivity of demand charge savings to the specific customer load shape, however, estimates of demand charge savings would ideally be done on a customer-specific basis using historical 15-minute interval load data and should account for the specific type of demand charges that are to be applied.

[7] Note, however, that California's net metering legislation provides additional benefits to commercial PV customers that are not analyzed in this report, namely a waiver of standby charges and a requirement that utilities not charge solar customers differently than other similar customers

1. Introduction

The solar power market is growing at a quickening pace, fueled by rapid technological advancements, concerns about global climate change and energy security, and an array of national and local initiatives and policies (Rogel 2005; Payne et al. 2001; Makower and Pernick 2004). Though these national and local policies take many forms, they most commonly include up-front capital cost rebates or ongoing production-based incentives (Haas 2003; Bolinger and Wiser 2002). Such programs are often supplemented by net metering requirements to ensure that customer-sited photovoltaic (PV) systems offset the full retail electricity rate of the customer-host (Cooper et al. 2006).

Somewhat less recognized is the importance of retail rate design (beyond net metering) for the customer-economics of grid-connected PV systems. Retail rates may contain flat or time-varying *energy* ($/kWh) charges and, for commercial customers, often *demand* ($/kW) charges as well. Given the substantial value that PV customers receive through utility bill savings, it stands to reason that the details of how these charges are structured is likely an important determinant of the economics of customer-sited PV systems.

The objective of this report is to examine the impact of retail rate design on the customer-economics of grid-connected, commercial PV systems in California.[8] We focus on California for four reasons. First, California's solar market is the largest in the United States, and the third largest in the world, behind Germany and Japan. Recent policy changes in California – including the establishment of a 10-year, $3.3 billion solar incentive program intended to motivate 3,000 MW of new customer-sited solar installations – suggest that California will continue to be a sizable solar market for years to come. Second, as part of this program, the California state legislature requires that PV customers ultimately use "time-variant" pricing, so issues of rate design are currently of interest to solar stakeholders in the State. Third, as a result of the State's efforts to encourage PV installations since the late 1990s, a large number of commercial solar installations exist from which PV production and load data are available. Finally, California's electric utilities have developed a wide range of retail rate structures, allowing a reasonably thorough analysis of the impact of variations in rate design on the value of customer-sited commercial PV. Because of the breadth of different retail rate structures used in California, this analysis may be applicable to other states.[9]

Our analysis is based on contemporaneous, 15-minute interval building load and PV production data from 24 actual commercial PV installations in California.[10] After scaling PV production to equal 2% and 75% of annual customer load, we estimate the annual utility bill savings per unit of energy produced by the PV system for each of the PV system/load combinations across 20

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[8] The report does not analyze the impact of retail rate design for residential PV systems.

[9] That said, because we are restricted to California's existing retail rates, this report does not address some rate design issues that are of relevance in other states, in particular the impact of standby and backup charges on the economics of PV. Neither standby nor backup charges are applied to solar installations in California. We recommend that future analysis consider the impact of these types of charges on the economics of commercial PV.

[10] Twenty of the datasets were provided by companies that market solar system data acquisition systems, with the remaining four datasets provided by government facilities.

distinct retail rates currently offered by the State's five largest electric utilities.[11] We then compare in detail these bill savings (both the total savings and the savings on demand and energy charges, individually) across all permutations of load/PV datasets and rate schedules, and seek to explain the variation in commercial PV economics based on:

- Overall rate levels (i.e., the magnitude of the utility's revenue requirements);
- Rate design and structure;
- The size of the PV system in relation to customer load served;
- The shape of the customer's load profile; and
- The shape of the PV production profile.

In examining the impact of differences in rate design and structure, we focus specifically on:

- The relative size of demand-based and energy-based charges in commercial tariffs;
- The type of demand charge assessed (e.g., whether they are based on annual or monthly peak demands, and whether they have a time-of-day [TOD] component);
- The definition of the summer on-peak period for TOD-based demand charges;
- The type of energy charge assessed (e.g., whether rates are differentiated by time-of-use period or only by season); and
- The difference between peak and off-peak period rates, for rate schedules with time-of-use-based energy charges.

For much of the analysis in this report, we assume that customers remain on the same retail rate before and after the installation of a PV system, and that PV output is net metered according to the specific net metering rules of each utility. However, we also conduct separate analyses in which these two assumptions are relaxed. In one alternate scenario, we calculate the value of PV under the assumption that customers choose the bill-minimizing rate before and after PV installation, from among each set of rates offered by a utility to a common class of customers (e.g., the set of rates offered by PG&E to customers with peak demands of 200-500 kW). In a second alternate scenario, we calculate the value of PV under the assumption that net metering is *not* available, in order to show the financial losses that commercial PV customers in California could potentially face if net metering were eliminated.

The results of the analysis presented in this report should be of value to: regulators and policymakers who have the authority to approve the design of retail electricity tariffs and want to understand the impact of those tariffs on the economics of commercial PV systems; stakeholder groups who wish to influence those rate design decisions; end-use customers who need to estimate the potential bill savings from PV installations; and PV retailers and consultants who have an obligation to assist customers in determining the value of PV investments and in selecting the retail rate that will maximize that value.

[11] These utilities are Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), Los Angeles Department of Water and Power (LADWP), and the Sacramento Municipal Utility District (SMUD).

The remainder of this report is structured as follows:

- **Chapter 2** highlights the basic characteristics of commercial electricity tariffs, elucidates the principles of rate design, and reviews previous research upon which our work builds.
- **Chapter 3** describes the retail rates, customer load and PV data, and basic analysis methods used in this report.
- **Chapter 4** presents the value of PV across the rate schedules analyzed, focusing on the base-case assumptions in which net metering is available and the customer remains on the same retail rate before and after the installation of a PV system.
- **Chapter 5** seeks to explain the variation in the value of PV, presented in Chapter 4, in terms of the impact of rate levels, rate structure, demand and energy charge design, customer load shape, PV system size, and PV output profile. The in-depth analysis presented in this chapter is the basis for a number of major conclusions, but the report is structured such that this chapter does not have to be read in detail to follow the rest of the report.
- **Chapter 6** relaxes the earlier assumption that customers must stay on the same rate before and after installing a PV system, and demonstrates the potential value of rate switching, especially when PV represents a sizeable portion of facility load.
- **Chapter 7** estimates the value of net metering under different rate structures, customer load profiles, and PV penetration levels.
- **Chapter 8** concludes with a summary of our major findings.

2. Background: Rate Design Methods, Principles, and Applications

2.1 Retail Rate Treatment of Customer-Sited PV

In general, customers can benefit financially from onsite generation either by selling the output to the utility at a specified contract price or by using it to meet onsite load and thereby avoiding the purchase of electricity at retail prices. In some countries (e.g., Germany), it is common for customers with PV to sell the output to the utility through a dedicated solar "feed-in" tariff. In the U.S., however, customers with PV generally use it to meet onsite load, and many states have adopted policies to support this type of arrangement.

Two particular policies are important in this regard. First, some states, including California, have eliminated standby and backup charges for customer-sited PV. These charges, which can significantly degrade the economics of onsite generation, are intended to recover the fixed-costs of serving customers in the event that the customer's onsite generation unit does not at all times fulfill the customer's entire electricity demands. Second, many U.S. states have adopted net metering requirements. Though the specific design of net metering rules and their attractiveness to PV customers varies considerably among U.S. states, generally speaking, net metering allows customers with PV systems to be credited for the generation from those systems at the retail rate prevailing at the time of production, regardless of the customer load at that time (Hughes and Bell 2004; Cooper at el. 2006). Given the intermittent profile of PV production, there may be periods when PV production exceeds customer load; net metering allows these differences to be "netted" over a longer period of time. Under California's current net metering law, for example, any excess credit in one month (i.e., remaining credits for PV production in excess of utility costs) is carried forward to the following months, over a one-year period. At the end of the year, however, any net excess credit is zeroed out (i.e., donated to the utility with no compensation).

In addition to these policies, the basic structure and design of retail electricity tariffs can impact the economics of commercial PV installations that are intended to offset onsite load, as discussed qualitatively below and as analyzed in detail in this report.

2.2 Rate Design for Commercial Customers in the United States

Electric utility rates are set with oversight from regulators to recover the cost of providing service and to provide a reasonable return on investment for utility shareholders. For traditional, vertically-integrated utilities, rates recover the costs of generation, transmission, and distribution. In regions with retail competition, where customers can purchase their generation service from a competitive supplier, regulators continue to have oversight over rates charged by utilities for distribution service, and they may also have oversight over rates charged for the default generation service provided to customers who have not switched to competitive suppliers.

In addition to overall utility cost recovery, regulators balance several goals in setting retail electricity rates. One important goal is economic efficiency, meaning that customers should be charged rates that reflect the cost to the utility of providing an additional unit of service to that customer. Other important goals include equity, rate stability, innovation, administrative ease, and environmental protection (Bonbright 1961; Weston 2000).

In evaluating the economic efficiency of different rate structures, it is important to understand what drives utility costs in the short- and long-term, acknowledging that the drivers may differ for generation, transmission, and distribution. Cost drivers may include the number of customers, customer and/or system peak load, and the amount of energy consumed. These drivers often result in the imposition of three distinct types of customer charges for commercial ratepayers in the United States:

- **Fixed recurring customer charges,** denominated as a fixed monthly or daily charge;
- **Demand charges,** assessed on "peak" customer demand (kW); and
- **Volumetric energy charges,** assessed on energy consumption (kWh).

Two of the primary challenges of rate setting are determining how to divide costs between these three categories and how to specifically design each charge, taking into consideration the various objectives of rate design. Substantial debate exists on these topics (Bonbright 1961). In part as a result, the allocation of the total customer bill among these components, as well as the structure of the individual components, can differ significantly across rates. Demand charges are often, but not always, assessed on the customer's maximum demand measured over 15-minute intervals. The maximum demand may be defined in various ways: it may be determined over all hours or during specified time-of-day (TOD) periods; and in either case, it may be established on an annual or seasonal basis or re-established during each monthly billing period. In addition, demand charge rate(s) may be constant over the year or may vary by season or TOD period. Energy charges, meanwhile, may be based on a single flat $/kWh rate applicable at all times during the year, tiered rates, seasonally-differentiated rates, time-of-use rates, or hourly rates that reflect contemporaneous marginal supply costs.

2.3 Impact of Retail Rate Design on the Value of PV: Literature Review

One can discuss the value of PV systems from a variety of perspectives. From the perspective of the electric utility and its ratepayers, much of the value of PV comes in the form of avoided fixed and variable costs associated with the generation, transmission, and distribution of electricity.[12] From the perspective of society at large, the value of PV includes the same set of avoided costs enjoyed by the utility, and in addition avoided externalities (e.g., associated with emissions or land use) and other benefits. Finally, from the perspective of a customer with a PV system installed at its facility, the economic value of a PV system derives in large part from savings on electric utility bills. It is this last perspective that is the focus of this report.[13]

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[12] Literature that has focused on avoided variable costs in terms of the correlation between PV production and wholesale market prices includes Borenstein (2005); Rowlands (2005); Maine and Chapman (2007); and Letendre et al. (2001). Avoided fixed costs tend to be highly site-specific, and are often tied to the effective load carrying capacity of PV. Literature that has addressed the reliability or effective load carrying capacity of PV, on a system-wide basis, include Perez et al. (1994, 2001, 2006). Others who have sought to evaluate the benefits of PV in offsetting the fixed costs of transmission and distribution investments include: Wenger and Hoff (1995); Wenger et al. (1996); Lambeth and Lepley (1993); Hoff (1996, 1998); Hoff et al. (1996, 2003); Shugar et al. (1992); and E3 (2005a,b,c, 2006).

[13] Thus, we side-step the broader issues of designing rates to most accurately reflect the societal benefits and costs of PV systems (economic efficiency) or to most accurately reflect principles of cost causation and equity. We acknowledge, however, that there is debate on these topics (e.g., the extent to which PV systems offset transmission and distribution expenditures and cross-subsidization issues associated with net metering).

Referring back to the three components of retail electricity rates discussed earlier, it is self-evident that a customer-sited PV system will not change the fixed component of a customer's bill, presuming that the customer remains connected to the electrical grid. However, PV systems may offset both demand and energy charges. Predicting the effect of PV systems on the energy component of a utility bill is relatively straightforward and only requires hourly PV production data, which in many cases may be simulated. Calculating reductions in demand charges is more complicated and customer specific, as it depends on the correlation between the time-varying output of the PV system and the time-varying building load, and may therefore require customer-specific 15-minute PV production and contemporaneous load data. Demand charge savings may also change over time as customer load shape varies, and are therefore less predictable than energy charge savings. As a result, it is not abnormal for potential solar customers to either ignore or heavily discount any claimed or estimated demand savings, and for solar advocates to call for optional "PV-friendly" rates that eliminate most demand charges and that instead roll costs into volumetric energy charges (Smeloff et al. 2006; WGA 2006).

A variety of authors have examined the extent to which PV systems can reduce customer peak demand and/or demand charges across a range of commercial customers. Using 21 load datasets and simulated PV production data from sites across the United States, Perez et al. (1997) estimated the customer-based effective load carrying capacity (ELCC) of PV systems for a range of customer load types. The ELCC is a statistical estimate of the expected reduction in building load due to the production of power by an onsite PV system. In later work, Perez et al. (1998) explore the value of commercial PV systems across the United States, using a large number of actual rate structures and utility-wide ELCC values to estimate demand charge savings. Often the match between PV production and customer load is good, but periodic cloud cover or a slight offset between peak PV production and peak building load can degrade the demand savings possible with PV systems. To mitigate this effect, Perez et al. (2003) explore the concept of a "Solar Load Controller," whereby commercial building load is controlled to remedy short-duration mismatches between peak PV output and peak building load.

Several authors have examined rate design issues through case study analyses of individual commercial PV systems. Hoff et al. (1992) present a detailed case study of the estimated customer benefits of a PV system, using load and simulated PV data for the PG&E Research and Development office building. The results show that, for a PV system sized much smaller than the maximum demand of the building, the PV system leads to substantial reductions in both demand and energy charges using PG&E's A-10 and E-19 rates. The authors also find that the demand reduction benefit of the PV system is reduced from an average of 70% of PV capacity to less than 10% of PV capacity as the PV system size is increased relative to peak building load. Hoff et al. explain that this is due to the peak demand shifting from afternoon, when PV production is highest, to times when the PV system is not expected to produce significant amounts of electricity. Additionally, they show that the E-19 rate, which charges a TOU energy rate and two demand charges – one based on the maximum demand and a second based on the maximum demand in the peak period – leads to greater savings than the A-10 rate, which only charges a demand rate based on the maximum demand in the month and an energy charge that only varies by season. Bhattacharjee and Duffy (2006) also take a case study approach, focusing on a 26.5 kW PV system installed in Massachusetts. They find that the payback period for this system is 46 years if only energy charges are considered, but drops to 33 years if demand charge savings are incorporated.

Other studies that have examined issues related to rate design and PV include Hoff and Margolis (2004) and Pop (2005), both of which compare the value of PV systems to residential customers under time-of-use (TOU) rates versus standard flat rates. Herig and Starrs (2002) discuss the implications of fixed versus volumetric charges, as well as standby and back-up rates, on the economics of solar installations. Johnston et al. (2005) explore the impact of standby charges on distributed generation on a qualitative basis, while Firestone et al. (2006) establish the quantitative impact of standby charges and other rate structures on distributed generation in New York and California. Cooper et al. (2006) provide a recent review of the status and importance of net metering at the state level, while Duke et al. (2005) summarize the public policy rationale for net metering.

Based on this review of previous work it is apparent that several other authors have explored the value of PV systems under various rate designs. To our knowledge, though, no publicly available literature has systematically estimated avoided costs to commercial customers across multiple actual metered building load and PV production combinations, under a large number of different rate structures. The work presented here fills that void.

3. Data and Methods: Rate Schedules and Data Characteristics

3.1 Retail Rate Schedules

Based on the 24 building load and PV production datasets discussed later, we estimate annual utility bill savings across 20 distinct retail rates currently offered by California's five largest electric utilities: PG&E, SCE, SDG&E, LADWP, and SMUD.[14] In aggregate, these utilities serve roughly 80% of statewide electricity demand. The 20 rates analyzed here represent the full set of standard tariffs offered by these utilities to net-metered commercial and industrial (C&I) customers with peak demands greater than 100 kW.[15, 16, 17]

These rate schedules can be characterized by the type of demand and energy charges that are employed (see Table 1 for a summary of the rates included in our analysis, and Appendix A for further details on these rates).

- **Energy Charges:** In this report, energy charges are classified by the period over which the energy rate changes: in the "flat" category, the energy charge remains constant all year long; in the "seasonal" category, it changes between winter and summer; and in the "time-of-use (TOU)" category, it changes throughout each day depending on the time of day. For rates from the five utilities, TOU-based energy charges always have a higher cost of energy during the summer on-peak hours than during other hours of the year. Two rates in our sample, PG&E's A-1 and A-6, do not include any demand charges; instead, customers' entire electricity bills are based on the amount of energy used (in each TOU period) and a fixed monthly customer charge.
- **Demand Charges:** All of the remaining rates in our sample include demand charges. We define demand charges to be any charge based on peak power consumption during a specified time period (i.e. a $/kW charge) irrespective of the title given to the charge in the utility rate books.[18] These charges can be characterized by the period used to assess the charge (time-of-day, monthly, or annually) and by how often the value of the charge changes (either changing seasonally, or not changing at all). A time-of-day (TOD) demand charge is typically assessed based on the maximum demand during a specific TOU period. For instance, LADWP's A-3, C and A-2, B rates base demand charges on the maximum 15-

[14] We ignore the fact that each of the 24 load/production pairs represents a facility that is served by just one electric utility, and instead apply those datasets to each of the 20 rates included in our analysis. We also assume that each customer is eligible for each retail rate, while in reality many of the rates are restricted to customers of a certain size.
[15] Our analysis is based on utility tariff books, current as of January 2007.
[16] We do not include LADWP's A-2,D rate in the list of rates because net-metering is not available to customers on this rate.
[17] We assumed that customers connect to the electrical grid through poly-phase connections at unity power factor. For PG&E, SCE, and SMUD, we assumed that customers connect at a secondary voltage level, while for SDG&E and LADWP, we assumed that customers connect at a primary voltage level. We assumed primary voltages for LADWP and SDG&E because both utilities offer one or more of the rate schedules covered in this report only to primary voltage customers. In particular, LADWP does not offer secondary voltage service under any rate schedules available to customers with peak loads greater than 30 kW, and SDG&E offers its A-6 TOU rate only to customers at primary voltages. Finally, to calculate monthly utility bills, we assumed that monthly billing cycles coincide with the start and end of each month.
[18] As such, we consider "facilities charges" as a form of demand charge.

minute demand during "High", "Low", and "Base" periods; demand charges during the "High" period are much larger than those demand charges applied during the "Base" period.[19] On the other hand, SMUD's GS-TOU1 and GS-Demand rates are typical of annual fixed demand charges in that each bases its charges on maximum customer demand over the past twelve month period, irrespective of when that peak occurs. Monthly demand charges are based on maximum customer demand each month, irrespective of what time it occurs. In terms of changes to demand charge rates, seasonal demand charges make demand peaks in the summer season more costly than demand peaks in the winter (in addition, TOD demand charges will typically have demand rates that vary based on TOD period). A fixed demand charge values demand equally in both the summer and winter. Many of the rates considered in this report include multiple types of demand charges, and some rates also include facility charges, which we also define here as demand charges. In cases where multiple types of demand charges are included, we sometimes classify the rate by whether or not it has a TOD-based demand charge component.

Table 1. Commercial Rate Schedules Included in Analysis

Rates Evaluated in Analysis

Utility	Rate Name	Energy Charge Type	Demand Charge Type	
			Facility Charge	Demand Charge
LADWP	A-2, A	Flat	Annual, Fixed	Monthly, Seasonal
	A-2, B / A-3, C	TOU	Annual, Fixed	TOD, Seasonal
PG&E	A-1	Seasonal	-	-
	A-6	TOU	-	-
	A-10	Seasonal	-	Monthly, Seasonal
	A-10 TOU	TOU	-	Monthly, Seasonal
	E-19	TOU	Monthly, Fixed	TOD, Seasonal
	E-20	TOU	Monthly, Fixed	TOD, Seasonal
SCE	GS-2, Non-TOU	Seasonal	Monthly, Fixed	Monthly, Seasonal
	GS-2, TOU Option A	TOU	Monthly, Fixed	-
	GS-2, TOU Option B	TOU	Monthly, Fixed	Monthly, Seasonal
	TOU-GS-3 Option A	TOU	Monthly, Fixed	-
	TOU-GS-3 Option B	TOU	Monthly, Fixed	TOD, Seasonal
	TOU-8	TOU	Monthly, Fixed	TOD, Seasonal
SDG&E	AL-TOU	TOU	Monthly, Fixed	TOD, Seasonal
	A-6 TOU	TOU	Monthly, Fixed	TOD, Seasonal
SMUD	GS-Demand	Seasonal	Annual, Fixed	-
	GS-TOU3	TOU	Annual, Fixed	TOD, Seasonal
	GS-TOU2	TOU	Annual, Fixed	TOD, Seasonal
	GS-TOU1	TOU	Annual, Fixed	-

[19] The SDG&E A-6 TOU rate assesses a demand charge based on a customer's demand at the time of the system peak during the "On-Peak" TOU period each monthly billing cycle. Historical SDG&E system load was collected for years prior to 2006 using FERC Form-714. Because sub-hourly data were not available, it is assumed that the system peak occurs at the same time as the highest building load within the hour of the system peak. System load data were not available for 2006 at the time of this project. It is therefore assumed that the time and day of the monthly system peak in 2006 was the same as the nearest weekday in 2005.

Many of the rates included in our analysis also include fixed customer charges. Because PV systems can in no instance reduce fixed, recurring charges, any rates that contain sizable charges of this type will not be favorable to PV installations. As shown later, however, fixed charges are a very small portion of the overall cost of electricity among the rates analyzed in this report. As such, we include the fixed demand charges in the customer bill calculations but we do not focus on the impact of fixed customer charges on the value of PV in the analysis that follows.

The 20 rate schedules included in our analysis are each designed for particular customer sizes (see Figure 1). Despite this, to simplify and broaden the analysis, we ignore size limitations in the bulk of the evaluation that follows. Instead, we apply all of the 24 customer load shapes to each rate irrespective of the actual magnitude of customer demand. In so doing, we make the assumption that even though rates are designed for a particular class of customers, the load shapes in the 24 datasets in our sample are representative of customers located in any of the utility service territories in California as well as the customer classes covered by each individual retail rate.

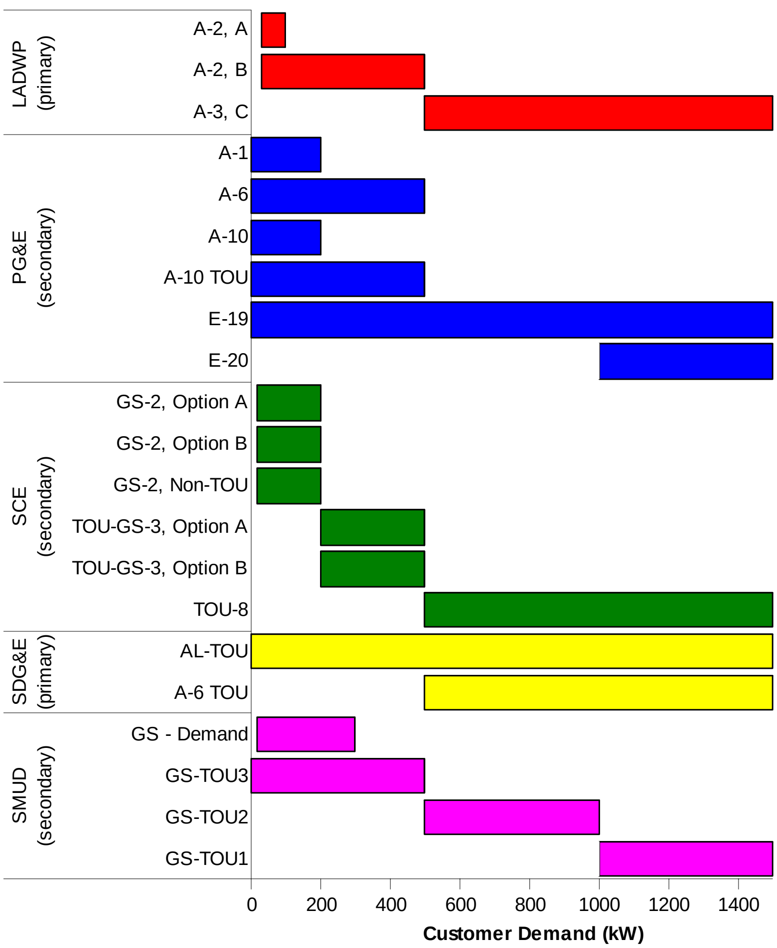

Figure 1. Applicability of Rates Based on Customer Size

One possible concern with this approach is that fixed customer charges will have a proportionally different impact on customers of different sizes. For instance, a large fixed monthly charge will represent a relatively small part of the total bill for a large industrial customer, while the same fixed charge for a small commercial customer will make up a larger part of its bill. When a customer remains on the same rate before and after the installation of a PV system, the fixed customer charge will not change and will therefore have no impact on the value of PV, calculated as the difference in customer bills before and after the installation of the PV system. In Chapter 6, however, we account for the fact that in certain cases customers may be able to choose between multiple (but not all) retail rates. In this case, fixed customer charges may change as a result of customers switching rates, and changes in fixed customer charges are included as part of the value of PV. Because fixed customer charges are modest for all of the 24 customers in our sample, however, and because customers may only switch between a limited number of rates that are generally available for a small range of customer sizes, our approach does not introduce significant inaccuracies.

California's Million Solar Roofs bill, SB1, requires "time-variant" pricing for customers with PV systems. In response to concerns about the initial deleterious effects of this provision on the California solar market, however, legislation has since been enacted and new regulations have been established to delay implementation of this pricing provision until after the IOUs' next set of general rate cases.[20] Thus, at the present time at least, all of the twenty rates analyzed in this report, including those without time-varying pricing, are available to customers with PV.

Finally, consistent with current practice in California, the bulk of our analysis assumes that net metering is allowed, and that no standby or backup charges apply to PV.[21] Under California's net metering law, any excess credit in one month (i.e., remaining bill credits for PV production in excess of utility costs) is carried forward to the following months, over a one-year period. At the end of the year, any net excess credit is zeroed out, and thereby provided for free to the local utility. In Chapter 7, we relax the net metering assumption to estimate the value of this policy to commercial PV customers in California. This report does not, however, evaluate the benefits of the standby/backup charge exemption to commercial PV systems installed in the State.

[20] SB 1 specifically notes: "The commission shall develop a time-variant tariff that creates the maximum incentive for ratepayers to install solar energy systems so that the system's peak electricity production coincides with California's peak electricity demands and that assures that ratepayers receive due value for their contribution to the purchase of solar energy systems and customers with solar energy systems continue to have an incentive to use electricity efficiently."

[21] In addition, we assume that no departing load or system benefits charges are levied on energy generated by PV systems, consistent with current practice. However, recent legislation (SB 1) may alter this practice (for the investor-owned utilities), with certain charges made truly non-bypassable.

3.2 PV Production and Building Load Data

We obtained 15-minute interval PV production and customer load data for 24 actual commercial sites with PV installations in California.[22] Each dataset includes at least one full year of PV production and building load data. Fat Spaniel Technologies[23] and SPG Solar, Inc.[24] provided 20 of 24 datasets. The remaining datasets were acquired directly from government facilities with onsite solar installations.[25] The data were collected over different time periods, with the earliest dataset covering the time period of January 1, 2004 to December 31, 2004 and the most recent dataset collected between July 12, 2005 and July 12, 2006.[26] The 24 customer load/PV datasets are diverse in geographic breadth, PV system size, and customer load shape.

The PV installations represented within our dataset are located across California, as shown in Figure 2, with a majority in the Northern Coastal and (inland) Valley regions.

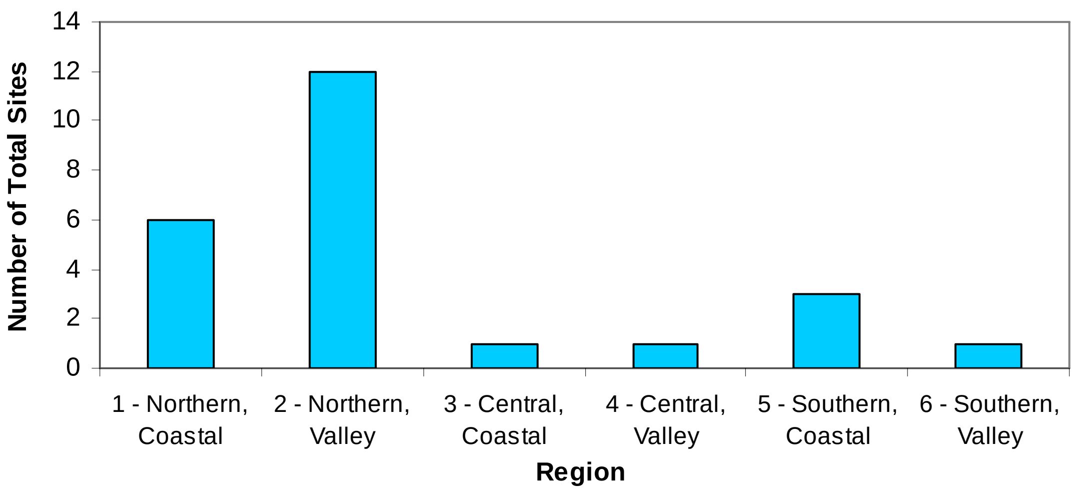

Figure 2. Geographic Location of PV Facilities within California

Among our 24-customer sample, the proportion of annual building load served by PV varies from less than 2% to as much as 140% (see Figure 3). Because the meters used in this case may be recording demand for only the building on which the PV system is located, and not the entire customer's site, these proportions may or may not represent the amount of the entire facility's demand met with solar.

[22] Actual facility names, locations, and PV project sizes are held in confidence.
[23] Fat Spaniel develops software and web-integration platforms for visualization and monitoring of renewable energy systems. Fat Spaniel data – including building load and PV output – were size-normalized to preserve confidentiality. For the purpose of calculating fixed customer charges, which may vary across rates, we assumed that the PV system size for the Fat Spaniel facilities was 250 kW.
[24] SPG Solar develops and builds solar systems, which are monitored with the web-enabled SunSpot solar monitoring system.
[25] The solar data for three of the facilities were collected by PowerLight Corp., a company that designs, installs, and operates solar systems. The load data were monitored and collected by Chevron Energy Solutions, an energy services company. The final dataset was provided by an engineer responsible for monitoring a government facility and solar system.
[26] Further details on each dataset are located in Appendix B.

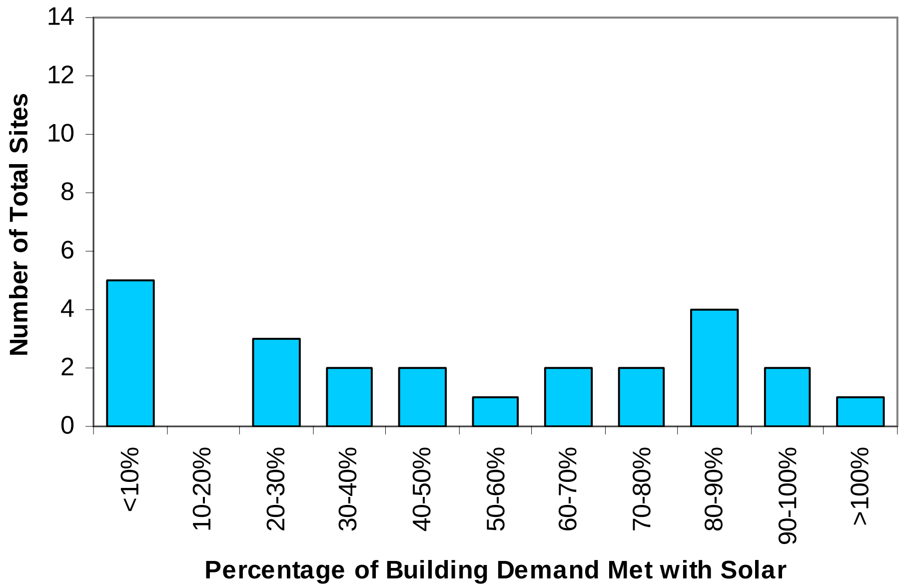

Figure 3. Portion of Annual Customer Demand Met with PV (PV Penetration)

The load shapes of the customers included in our sample are also diverse, as shown in Figure 4 and Figure 5. Figure 4 summarizes the distribution of load factors across the sample. A customer's load factor is equal to the ratio of a facility's average power consumption over the course of a year to its peak demand.

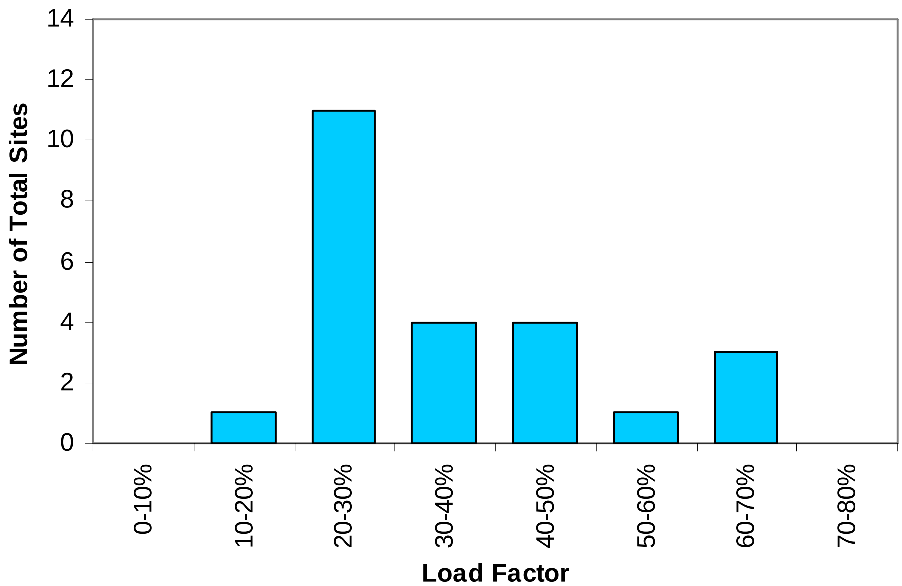

Figure 4. Load Factor of Buildings without PV System Installed

Diurnal load shapes also vary within our sample, and include many facilities with typical afternoon peaks, but also a good number of facilities with relatively flat diurnal demands or even inverted profiles where load is greatest during off-peak periods. Figure 5 shows the distribution of a parameter that we use to characterize the diurnal nature of a customer's load shape. The parameter is the ratio of the percent of total electricity demand during the summer peak period to the percent of time that is defined as summer peak for each utility. A value above one indicates that proportionally more energy is consumed during the summer peak period than during other periods of the year; a high value therefore corresponds to a facility with a large afternoon peak during the summer.

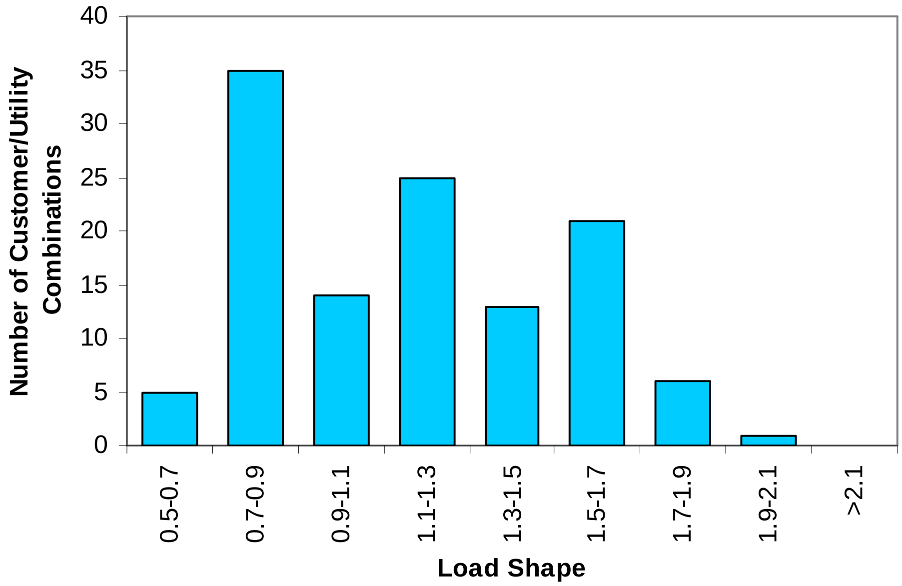

Figure 5. Diurnal Load Shape of Building Demand without PV System Installed

3.3 Data Cleaning Procedures

Raw PV production and building load data were cleaned to remove seemingly inaccurate spikes in load and solar data, error tags, and other anomalous data points.[27] Anomalous data were identified by visual inspection of the datasets.[28] In the 24 datasets, a total of 190 events were identified as anomalous.[29]

[27] The IEC Standard 61724: "Photovoltaic system performance monitoring – Guidelines for measurement, data exchange and analysis" was used for guidance on data quality assessment methods.
[28] Each set of PV production and load datasets were plotted in blocks of ten-day periods. Visual inspection allowed for identification of error tags, large spikes in data beyond what was normally observed, and questionable dropouts in PV production and building load.
[29] Identification of dropouts in PV production posed a challenge because PV systems are known to stop producing power even with high insolation rates due to inverter or other component problems. As a result, dropouts in solar production were only labeled as errors under either of two conditions. The first condition was that solar production during the dropout was zero; PV production at night was normally non-zero, and negative, due to power consumption by the PV components such as the inverter. The second condition was that load and PV production both showed significant drops simultaneously, indicating an error with the data acquisition system. Only six events were identified as anomalous due to dropouts in solar data. Many more solar dropouts occurred in the datasets, but they could not be justified as being erroneous data.

Two data cleaning methods were used to correct anomalous data: interpolation between surrounding data points and removal of data. The primary criterion for choosing between these two methods was the duration of the event. Short events, typically lasting an hour or less, such as extreme spikes in data, were cleaned by interpolation. Longer events, typically lasting half of a day or longer, such as extended dropouts in the data logging equipment, were cleaned by removing all data for the duration of the event.

Of the 138 events that were cleaned using interpolation, 69% were for periods shorter than one hour. Nearly 99% were shorter than four hours. A few events were longer than four hours, particularly if they occurred at night when PV production was near zero; the longest such period that was cleaned using interpolation lasted for 14 hours. In the case of longer events for which interpolation did not make sense, both the load and PV production data were completely removed from the datasets. Fifty-two such events occurred throughout the 24 datasets. 77% of these events persisted for shorter than one day and 92% were shorter than three days. Only four events were removed from the datasets that lasted longer than three days.[30]

All datasets had greater than 96% data availability, where data availability is defined as the number of unmodified data points divided by the total number of data points available over the one year time period with 15-minute data recording intervals (as defined in IEC 61724, Section 7). Twenty of the 24 datasets (83%) had 99% or greater data availability.

3.4 Basic Analysis Methods

The cleaned datasets were used to estimate the annual electricity bill for each facility, both with and without a PV system installed. The electricity bill with the PV system was calculated using net 15-minute electricity consumption, equal to gross consumption minus PV system production. During periods when the PV system generates more electricity than is used by the building, electricity is supplied to the grid and net consumption is negative.

As discussed earlier, in most of our analysis, we assume that the PV system is eligible for net metering, in which case energy produced by the PV system in excess of what is used by the building during any 15-minute interval results in a bill credit based on the prevailing energy rate of the customer's rate schedule.[31] The electricity bill when net metering is available is calculated by assuming that, over a one-year period, a facility is able to reduce its entire bill, including fixed customer charges, to zero with a PV system on either LADWP or SMUD rates, consistent with current practices. In the case of the IOUs, however, a PV system can at most reduce the bill to the fixed monthly customer charge, consistent with current practice among the IOUs.

Further details of the specific methods used for our analysis are provided throughout the remaining chapters of the paper.

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[30] Two of the events lasted for four days, one event lasted for six days, and the final event persisted for seven days.
[31] Thus, if the customer is on a TOU rate schedule, excess energy produced by the PV system during the on-peak period is credited against the customer's bill based on the on-peak energy rate.

4. The Value of Commercial PV with No Rate Switching

In this chapter we present the electricity bill-savings value of commercial PV systems in California. We assume that the facility remains on the same retail rate schedule before and after the installation of the PV system, and that net metering is available.

4.1 Detailed Analysis Methods

The value of a PV system in reducing a facility's electricity bill can be determined by comparing the customer's estimated electricity bill without a PV system to that customer's electricity bill with a PV system installed. The *value of PV* when it is assumed that a facility remains on the same retail rate before and after installing the system is defined here as the difference between estimated customer-specific electricity bills based on gross demand and net demand, divided by the total amount of energy produced by the PV system.[32,33]

$$Value\ of\ PV\ (VPV) = \frac{Total\ Bill\ without\ PV - Total\ Bill\ with\ PV}{Annual\ PV\ Energy\ Production} \quad (\$/kWh)$$

It is clear from the above relationship that the total bill savings of a PV system will depend on the value of PV, which we investigate in detail in this analysis, and the annual energy production of a PV system, which will be affected by system size and orientation, insolation levels, and expected performance degradation over the system life. For the purpose of our analysis, expressing the value of PV on a per kWh basis, rather than in absolute dollar terms, serves two purposes. First, it allows us to abstract from the specific size of the PV system, since it is a foregone conclusion that larger systems will generally produce larger absolute bill savings. Second, commercial customers in California and elsewhere are increasingly choosing to finance their PV systems through Power Purchase Agreements, whereby the customer purchases the PV output from a third-party owner on a per kWh basis; expressing the value of PV in the same units more readily allows for a direct comparison between the financial costs and benefits of PV from the customer's perspective in this instance.

The value of PV depends, in part, on how much of the gross facility demand is met by the PV system. The *PV penetration* is defined here as the amount of energy produced by the PV system over the one-year period divided by the total amount of energy consumed by the facility over the year, prior to the installation of the PV system.

$$PV\ Penetration = \frac{Annual\ PV\ Energy\ Production}{Gross\ Annual\ Energy\ Consumption} \times 100\ (\%)$$

[32] We assume for this analysis that the gross demand load shape is fixed and does not change with different utilities, customer class sizes, or rate schedules.
[33] The value of PV as calculated here should be considered to be the *pre-tax* value to the customer. Because utility bills are a deductible expense, the *after-tax* value of commercial PV systems for tax-paying entities would be lower than shown here.

For the purpose of our analysis, actual PV production data from each of our 24 customer load/PV production datasets are scaled to 2% and 75% penetration.[34] We scaled the PV production data in this way so that we could more easily analyze the impact of different factors – including PV penetration – on our ultimate results. Consequently, the net demand data are also scaled to maintain the relationship in which the gross demand is equal to the sum of the modified solar production and net demand. The electricity bill when a PV system is installed on the building is then calculated using the net demand instead of the gross demand. So, while actual PV production and customer load data are used in our analysis, some scaling is applied to those data to more easily extract key trends in the results.

We generate the values presented below by applying each of the 20 selected retail rates to the 24 distinct load/production datasets, yielding 480 values for annual PV-induced estimated bill savings. We ignore the fact that each of the 24 load/production pairs represents a facility that is served by just one electric utility, and instead apply those datasets to each of the 20 utility rates included in our analysis. We also assume that each customer load/production dataset is eligible for each retail rate, whereas in reality many rates are restricted to customers of a specific size. In many of the figures that follow in this and future chapters, we present the median value of our results, with error bars indicating the 10^{th} and 90^{th} percentile range.

4.2 Distribution of the Value of PV, Assuming No Rate Switching

Figure 6 provides a histogram showing the range of PV-induced rate reduction value (value of PV, or VPV) at PV penetration levels of 2% and 75%. Two important conclusions can be reached from this figure alone.

- First, the rate-reduction value of PV in $/kWh terms clearly varies substantially across electric utility rates and load/production datasets, ranging by more than a factor of four, from roughly $0.05/kWh to $0.24/kWh. This wide distribution reflects a variety of factors, including differences in customer load shapes, PV production profiles, electric rate structures, and the revenue requirements for each utility and rate class.[35]

- Second, it is apparent that the histogram shifts to the left with increased PV penetration. Larger PV systems, relative to building load, tend to have a lower rate-reduction value than smaller systems, on a per-kWh basis. Overall, the median rate-reduction value of PV declines from $0.143/kWh to $0.115/kWh when PV penetration increases from 2% to 75%, a drop of approximately 20%. As discussed later, this phenomenon largely reflects the fact that demand charge savings diminish with increased PV penetration.

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[34] We scale the PV production data to generate various hypothetical PV penetration levels for each load/production pair. The values of 2% and 75% were chosen to generate cases that bound the expected results. At 2% penetration, PV output is small enough that the PV system has little impact on the overall load shape of the customer; the magnitude of the peak load may change slightly, but the timing of the peak load does not drastically shift. On the other hand, a system that meets 75% of facility load annually may cause a significant shift in the timing of the load peak. We chose 75% in this case because even larger systems than this can sometimes result in decreased value per kWh because of the limitation that the electricity bill can at best be reduced to zero. Rates with TOU energy components begin to reach this limit with PV systems larger than 75% of annual facility load.

[35] Even if a LADWP and PG&E rate had the same exact structure, the value of PV would still be different between the two rates due to the lower revenue requirements of LADWP.

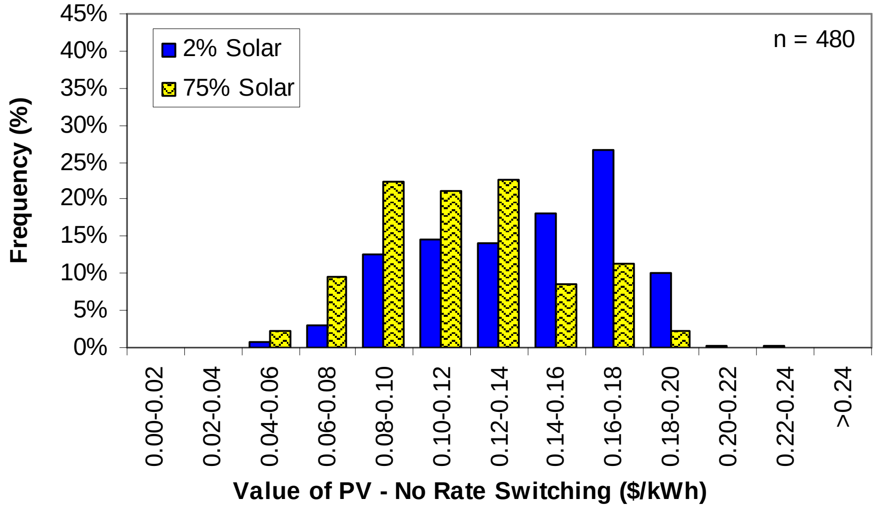
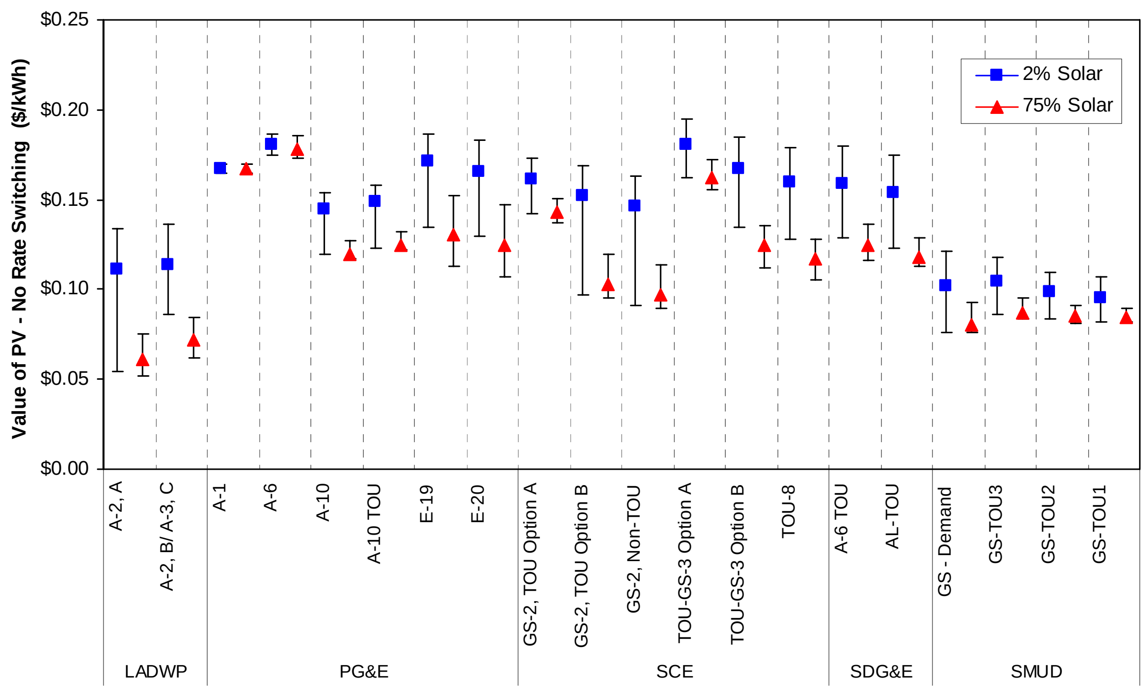


Figure 6. Histogram of Value of PV at Different Levels of Penetration (no rate switching)

4.3 Value of PV by Rate Structure, Assuming No Rate Switching

Figure 7 presents the same underlying results as above, disaggregated by utility and retail electricity rate. For each individual utility rate schedule and level of PV penetration, the figure shows the median and 10th/90th percentiles across the 24 load/PV datasets. The same results, in tabular format, are provided in Appendix C.



Median value with error bars for 10th to 90th percentile range

Figure 7. Value of PV at Different Levels of Penetration, by Rate Structure (no rate switching)

These results help to gauge how much of the overall variation in bill savings shown in Figure 6 is attributable to differences in the rates (both their structure and size) versus other factors, such as customer load shape and PV production profile. Figure 7 shows that, at a 2% PV penetration, the median value of PV ranges from roughly $0.10/kWh to $0.18/kWh across the 20 rates in our sample, representing roughly 46% of the variation across all data points at that penetration level ($0.05-$0.24/kWh). Because we use the same 24 customer load shapes to calculate the median value of PV for each rate, the difference in median value across rates is solely due to variation in the retail rates. In other words, at a 2% PV penetration level, approximately 46% of the overall variation in the value of PV is attributable *solely* to differences between retail rates. The remaining portion of the overall variation is attributable to other factors – namely customer load profile and PV production profile – although, as we will see in the next chapter, the impact of those factors depends to some degree on rate structure. At 75% PV penetration, the median value of PV across rates ranges from $0.06/kWh to $0.18/kWh, representing approximately 84% of the variation across all data points at that penetration level. As such, at higher PV penetration levels, rate design becomes a more important determinant of the value of PV, relative to other factors.

Two additional observations are worth noting.

- First, Figure 7 confirms that the general decline in the value of PV with increasing PV penetration illustrated in Figure 6 also applies to the vast majority of the individual retail rates. Almost universally, at higher levels of PV penetration (i.e., 75%), the customer value of PV drops, in some cases substantially. It is also evident, however, that the magnitude of this decline varies significantly among rates. For example, the drop-off on PG&E's A-6 rate is much less dramatic than for the utility's other rates.

- Second, the spread between the upper and lower percentile bands – which are the result of variations in customer load profiles and PV production profiles – differs substantially across rates and tends to be wider at 2% PV penetration than at 75%. This indicates that the shape of the customer's load profile and/or the PV production profile may be much more important determinants of the value of PV for some rates than others, and more so at lower PV penetration levels. Some retail rates provide similar value to all PV customers, regardless of the exact temporal profiles of PV production and customer load (e.g., PG&E's A-1 and A-6).

Finally, though the results presented here should be taken with caution, since they assume that customers are not able to select from different tariffs, this analysis appears to suggest that, at low levels of PV penetration, the most favorable rates for PV include PG&E's A-6[36] and SCE's TOU-GS-3 Option A. On average, at a 2% PV penetration level, customers taking service under these rates would earn roughly $0.18/kWh or more for PV output. At higher penetration levels, the most attractive rates statewide appear to include PG&E's A-1 and A-6, and SCE's TOU-GS-3 Option A. PG&E and SCE have a number of retail rates that are favorable to PV, at least at low levels of PV penetration. LADWP and SMUD's retail rates appear the least attractive for

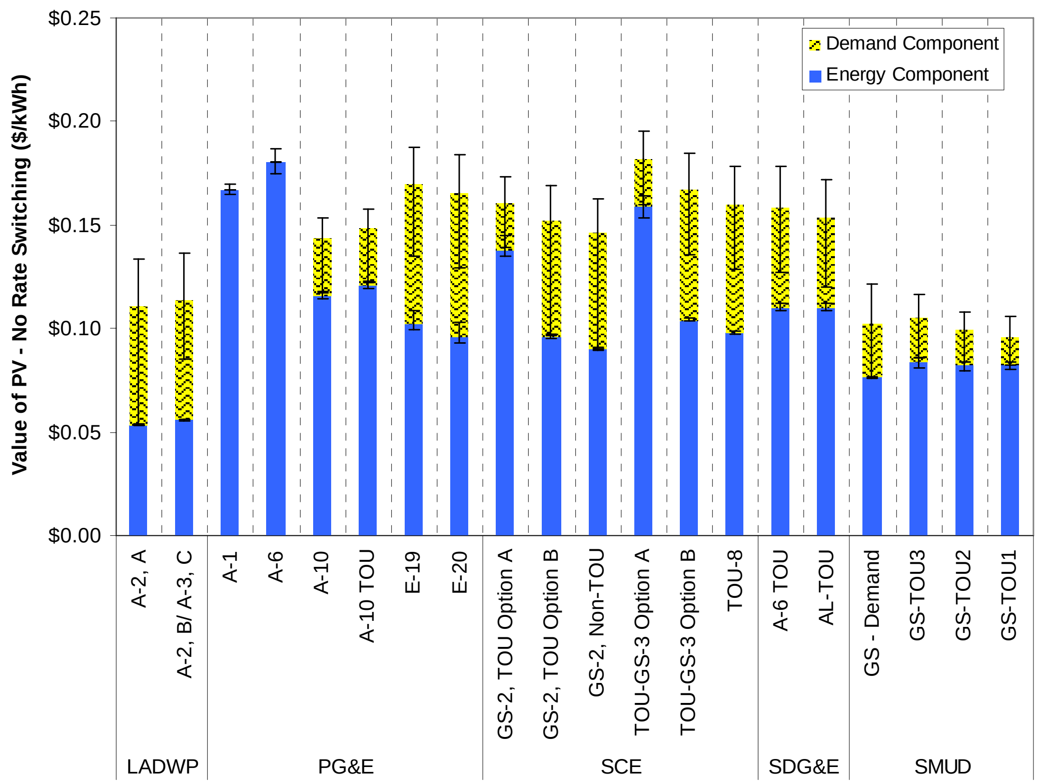
[36] The attractiveness of PG&E's A-6 tariff, which excludes all demand charges and instead only includes energy charges, has been cited as a major reason for the proliferation of commercial PV systems in PG&E's service territory, relative to other utility service territories in the State.

PV. All of these conclusions are based on an assumption of no rate switching, however, which as shown later can have a substantial impact on the economics of PV.

4.4 The Importance of Demand Charges

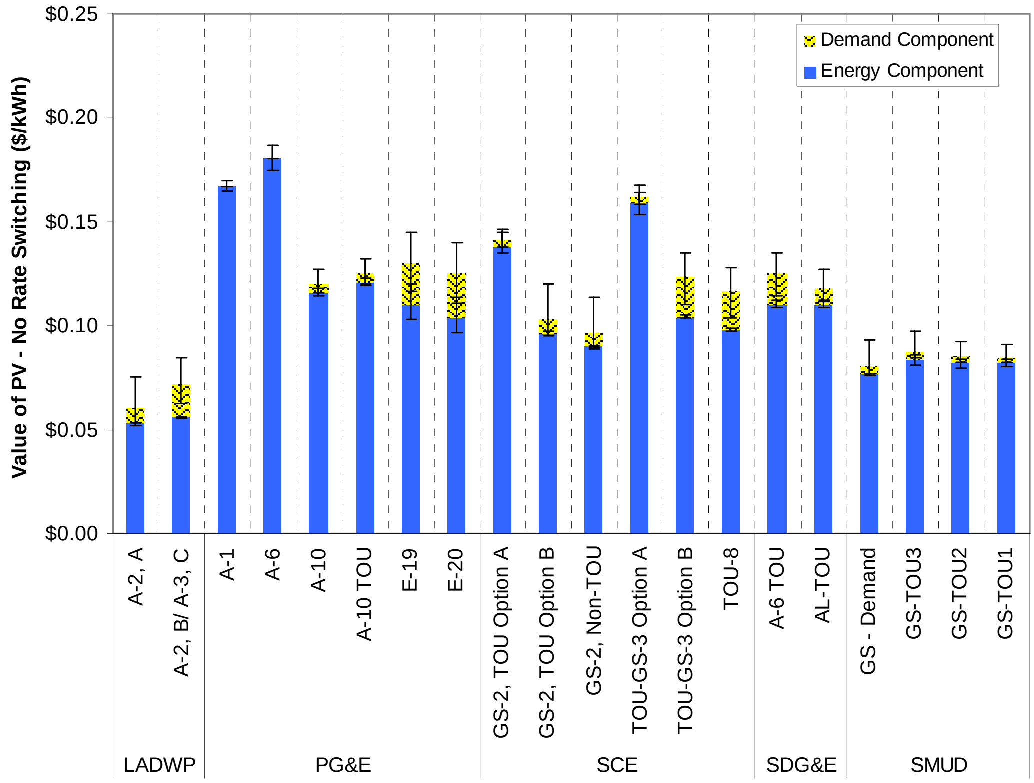
Figure 8 and Figure 9 suggest that the trends noted above are driven to a large extent by the influence of demand charges. Focusing first on Figure 8, we see that at low levels of PV penetration, a substantial portion of the value of PV can derive from demand charge savings, depending on the specific tariff in question. Under some rate structures, as much as half of the rate-reduction value of PV derives from demand charge savings. Clearly, PV systems that serve a small percentage of building load may, in fact, produce significant per-kWh savings on demand charges in some instances.

That said, it is also evident that, for any individual rate, the value of demand charge savings varies considerably more than savings on energy-based charges. This is shown by the wide spread between the 10th and 90th percentiles for the demand charge savings and the far more narrow spread for energy charge savings in Figure 8. This suggests that variations in the overall value of PV for each rate, as shown in Figure 7, are driven primarily by variations in the value of demand charge savings for different customers. As a result, those rates with larger demand charges tend to see a wider variation in overall PV-induced rate savings among customers, compared to rates that are dominated by energy-based charges.



Median value with error bars for 10th to 90th percentile range

Figure 8. Demand and Energy Savings at 2% PV Penetration



Median value with error bars for 10th to 90th percentile range

Figure 9. Demand and Energy Savings at 75% PV Penetration

Comparing Figure 8 and Figure 9 reveals that, at higher levels of PV penetration, the value of PV-induced demand charge savings (on a per-kWh basis) drops precipitously for all of the rates, while the value of energy charge savings remains relatively unchanged. The decline in the overall rate-reduction value of PV at higher PV penetration rates is therefore driven almost entirely by the decline in demand charge savings. At high PV penetration rates, the value of PV is dominated by energy charge savings.

4.5 Summary

The results presented in this chapter illustrate four basic findings:

1) The value of PV systems varies dramatically across the customers and retail rates in our sample – e.g., for commercial PV systems meeting 2% of annual building load, the value ranges from $0.05/kWh to $0.24/kWh.
2) Savings on demand charges can represent a significant portion of overall bill savings for commercial PV systems (as much as 50% of the total bill savings for some rate schedules), but these demand charge savings (on a per-kWh basis) decline significantly as the size of the PV system increases relative to building load.

3) As PV systems are sized to provide increasing levels of annual facility load, the per-kWh value of those PV systems may decline significantly for rates that contain significant demand-based charges.
4) For a given rate schedule and PV penetration level, savings on demand charges can vary substantially across customers, indicating that the specific characteristics of the customer's building load profile and/or PV production profile can be important determinants of the value of PV.

In the next chapter we explore these relationships in greater detail.

5. Determinants of the Value of Commercial PV, with No Rate Switching

The purpose of this chapter is to explore in more detail why the value of PV varies so greatly across rate structures and across the PV and load datasets in our sample. We seek to explain variations in the value of PV based on differences among retail electricity rates, including the average cost of electricity under each rate, the portion of the cost of electricity on each rate comprised of demand charges, the types of demand charges used, and the types of energy charge used. In addition to issues of rate design and structure, we also examine the impact of differences in customer load shapes and PV production profiles across our dataset, and the interrelationship between these factors and rate structure variables.

Though the detailed content of this chapter helps one understand important rate design issues, the material is quite technical, and uses a normalization metric for the value of PV that is not immediately intuitive. As a result, we begin in Section 5.1 by summarizing the important findings of this chapter so that readers who so wish may opt to skip the remainder of the chapter, and instead turn to Chapters 6-8. For those readers who desire a more-technical treatment of the material, we then address each of the explanatory factors identified above, and conclude the chapter by presenting the results of a regression model that reveals the relative significance of each of the various explanatory factors.

As described further later in this chapter, many of the results presented here are based on *normalized* values. It is important to note that it is the relative value of these normalized results that matters; the specific numerical values have no particular meaning. The reader is therefore cautioned to not interpret the normalized values presented in this chapter as representing the actual value of PV – that information is provided in Chapter 4.

5.1 Overview of Key Findings

Differences in the rate-reduction value of PV across rates and load/PV datasets are caused by numerous factors. As described in more detail in the remainder of this chapter, our key findings are as follows.

- *Average Cost of Electricity*. Some rates schedules are costlier than others, aside from any differences in rate *structure*, in which case each unit of energy offset by a PV system will generally also have a relatively high value. These differences in average electricity costs are most prominent across different electric utilities, each of which has a different per-kWh revenue requirement. We find that the average cost of electricity for customers without PV has the largest impact on the value of PV among all of the factors examined in this chapter.

- *Demand Weight*. Retail rates that rely heavily on demand-based charges are, in general, found to result in a lower value of PV. We define the *demand weight* of a particular retail rate as the percentage of the average cost of electricity under that rate that derives from demand-based charges. At a PV penetration level of 75%, we find that the demand weight of a retail rate is the second most-significant factor in determining the value of PV (behind the average cost of electricity). At a PV penetration rate of only 2%, however, the demand weight has a relatively minor impact on the value of PV because, as shown in Chapter 4, smaller PV systems are often able to significantly reduce the per-kWh cost of demand charges.

- *Demand Charge Structure*. The rate schedules analyzed in this report utilize a variety of demand-based charges. In all cases, the per-kWh value of demand charge savings from PV declines substantially as PV penetration increases, and is highly variable across customers. We also find that the value of demand charge savings is greatest, and least variable across customers, for rates with demand charges that are based on maximum monthly customer demand in the summer peak TOD period, when that period ends in late afternoon (rather than evening) hours. Demand-based charges that are levied based on peak monthly or annual demand, regardless of the temporal profile of that demand, or that have TOD demand charges based on a peak TOD period that extends into the evening hours, are found to typically result in a lower value of PV.

- *Customer Load Shape*. The ability of PV systems to offset demand charges depends, in part, on how well the PV system's output correlates with the customer load shape. We find that PV systems produce the highest and most consistent level of demand charge savings for customers with a summer afternoon peaking load shape, regardless of the type of demand charge assessed. Customers with flat or inverted load shapes are found to receive only modest savings on summer TOD demand charges, and little or no savings on other types of demand charges. When looking at our population of customers as a whole, customer load shape is the second most-significant factor affecting the value of PV at low PV penetration levels, diminishing in significance at higher penetration levels due to the declining ability of PV systems to offset demand-based charges.

- *Energy Charge Structure*. The design of energy-based charges also varies across rates, and can have an impact on the value of PV. For the purpose of this report, we characterize differences in the structure of energy charges across rates by the ratio of the summer peak TOU price to the winter off-peak TOU price. Across all PV penetration levels, we find that this price ratio is the third most-significant factor affecting the overall value of PV. A higher spread in peak to off-peak energy-based charges is found to result in a higher value of commercial PV systems given the positive correlation between PV output on on-peak periods.

- *PV Production Profile*. Interestingly, we find that differences in the temporal profile of PV production across the 24 systems in our dataset have relatively little impact on the value of PV in reducing demand- or energy-based charges. Rate design and customer load characteristics appear to have a more sizable impact on the $/kWh value of PV for commercial customers in California than the specific temporal profile on their PV system.

We now take up, in more detail, each of these six factors in turn, explaining the analysis conducted to arrive at the findings described above and presenting additional findings about the effects of these factors on the value of PV. The non-technical reader may wish to skip the remainder of this chapter, and pick up the text in Chapter 6.

5.2 Average Cost of Electricity

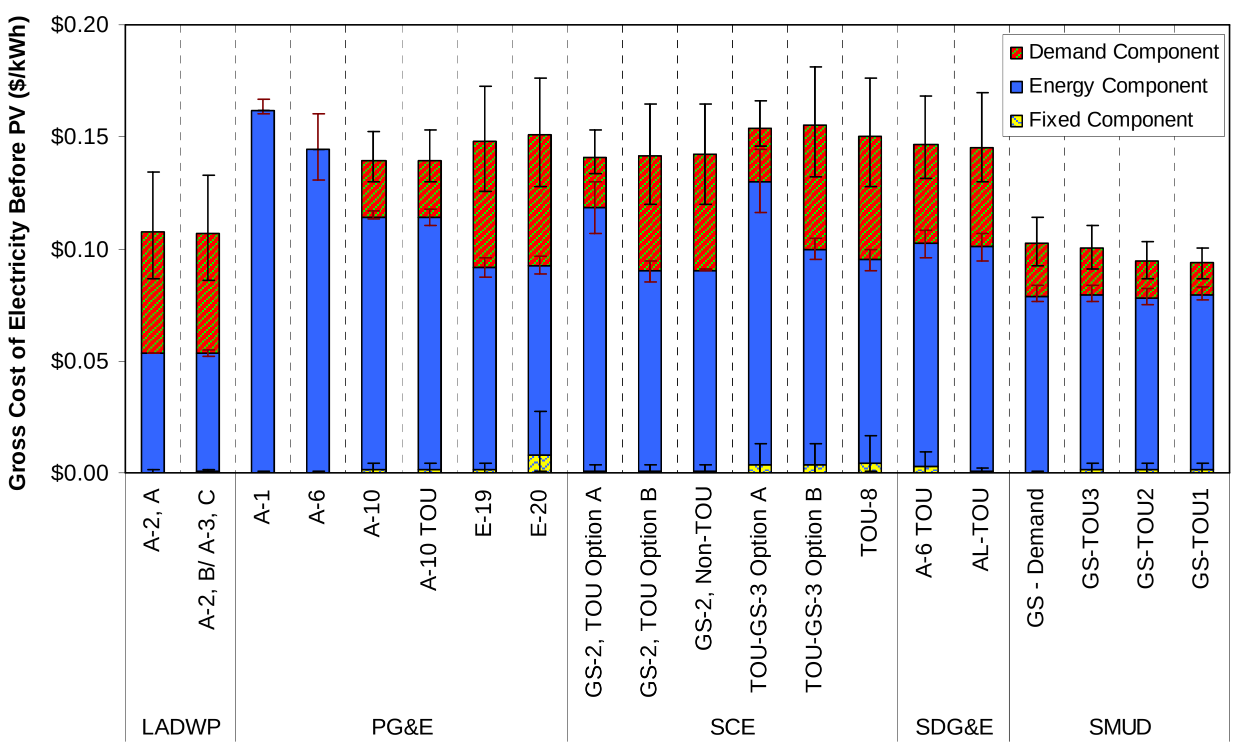
One major driver for differences in the value of PV across rates is simply that some rates are, on average, higher-cost than others, aside from any differences in rate *structure*. One way to gauge differences in rate levels is to compare the average cost of electricity across rates, for the 24 commercial facilities in our dataset (without a PV system installed).

The effective *cost of electricity* for a facility without a PV system is defined as the total estimated bill (including all energy, demand, and fixed customer charges) for a one-year period, divided by the gross amount of energy used by the facility during the same interval.

$$Cost\ of\ Electricity\ (COE) = \frac{Total\ Bill\ without\ PV}{Gross\ Annual\ Energy\ Consumption} \quad (\$/kWh)$$

As Figure 10 shows, the median cost of electricity is generally similar across the rates of *each* utility. SMUD's and LADWP's rates, however, are generally lower than the rates of the investor-owned utilities in our sample, demonstrating that the per-kWh revenue requirements of these publicly owned utilities are lower than for the State's IOUs.

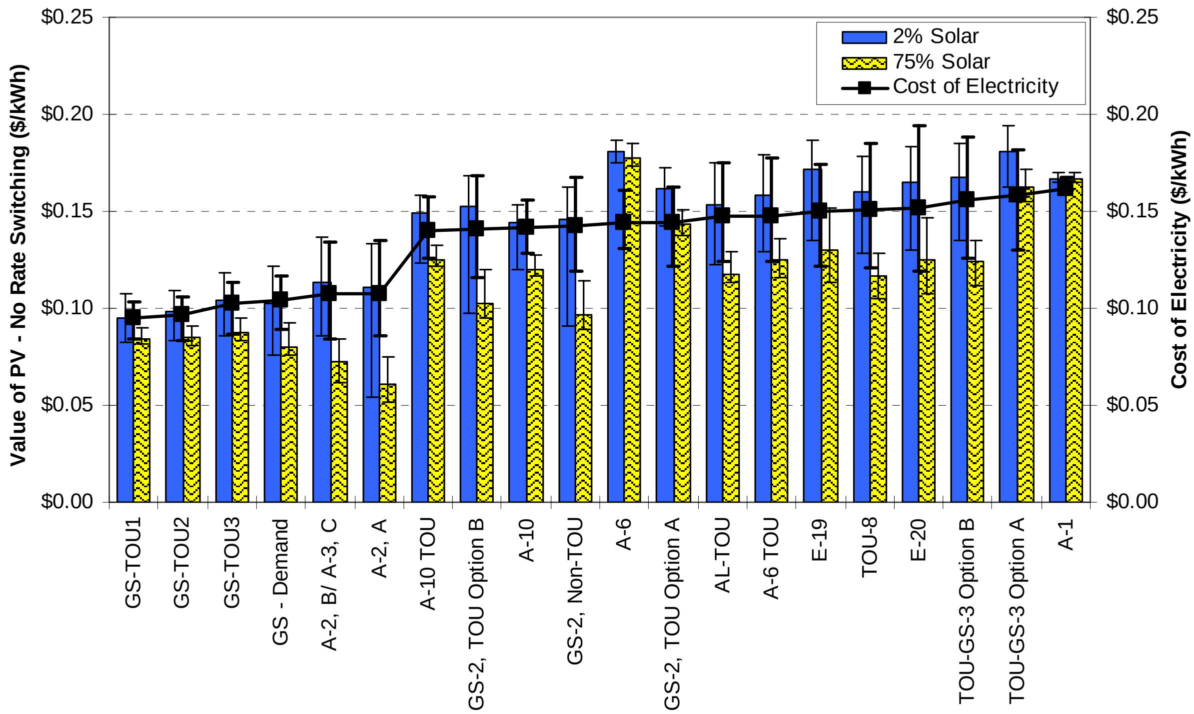
As a side note, Figure 10 also clearly shows that fixed customer charges are a small portion of the overall cost of electricity in California, among the rates and customers analyzed in this report. As such, the remainder of this report does not address fixed, monthly customer charges.



Median value with error bars for 10th to 90th percentile range

Figure 10. Gross Cost of Electricity by Bill Component

The impact of the rate level on the value of PV is powerfully illustrated in Figure 11. This figure presents the value of PV at 2% and 75% PV penetration (these results were first presented in Chapter 4) along with the cost of electricity for each rate (median, with 10th and 90th percentiles). The rates are ordered with increasing median cost of electricity. The figure clearly indicates that the rate level has a considerable impact on the value of PV to the customer. The low rate levels for LADWP and SMUD, for example, are accompanied by low values of PV. The close relationship of the cost of electricity and the value of PV is especially apparent at low levels of PV penetration – at 2% PV penetration, the value of PV is nearly equal to the cost of electricity for a median customer on many rates. The chart also shows, however, that a significant portion of the variation in the value of PV, especially at high levels of PV penetration, cannot be explained by the rate level alone.



Median value with error bars for 10th to 90th percentile range

Figure 11. Impact of Rate Level on the Overall Value of PV, Under Different Rates

To control for differences in rate *levels* – and thereby isolate the impact of rate *structure* – we normalize the value of the bill savings from PV. We do so by dividing the customer-specific rate-reduction value of PV for each customer-rate combination by the median cost of electricity of that rate across all 24 customers, prior to PV installation. We then multiply this value by the median cost of electricity (again, without PV) across all 20 rates ($0.135/kWh). This last step is conducted so that normalized values are expressed in $/kWh terms and can thereby be directly compared to un-normalized values. Normalization of the results in this manner helps to evaluate the effect of different rate structures on the value of PV even when the actual cost of electricity varies from one rate to another. The two figures below present these normalized results.

$$Normalized\ VPV = \frac{VPV}{Median\ COE\ \ for\ \ Rate} \times Overall\ \ Median\ COE\ \ (\$ / kWh)$$

The histogram in Figure 12 is analogous to Figure 6 from Chapter 4, except that the values are now normalized according to the procedure described above. The normalized results shown in Figure 12 are similar in two fundamental respects to those shown earlier: (1) we continue to see a wide variation in the value of PV at each PV penetration level, and (2) the value of PV clearly tends to decline at higher PV penetration levels. One important difference, however, is apparent. The distributions of normalized values in Figure 12 are significantly narrower than the distributions of un-normalized values in Figure 6, reflecting the fact that some of the variation in the value of PV is due simply to differences in overall rate levels.

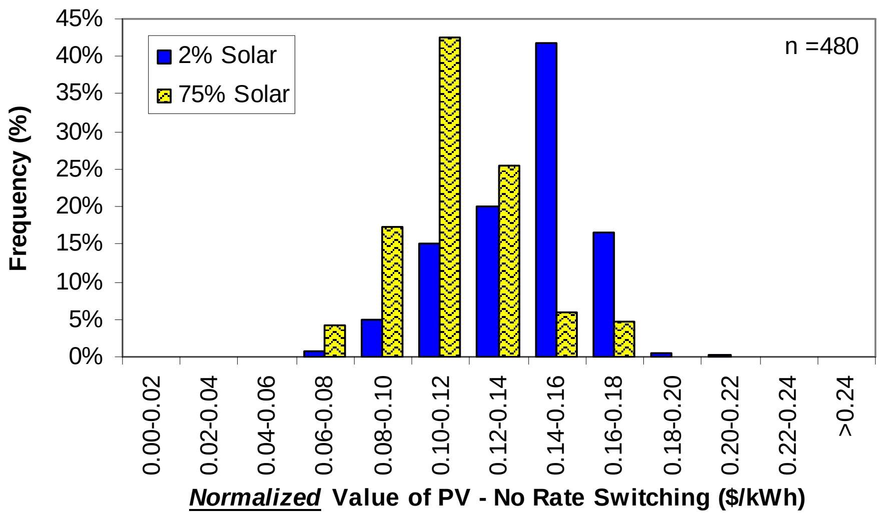
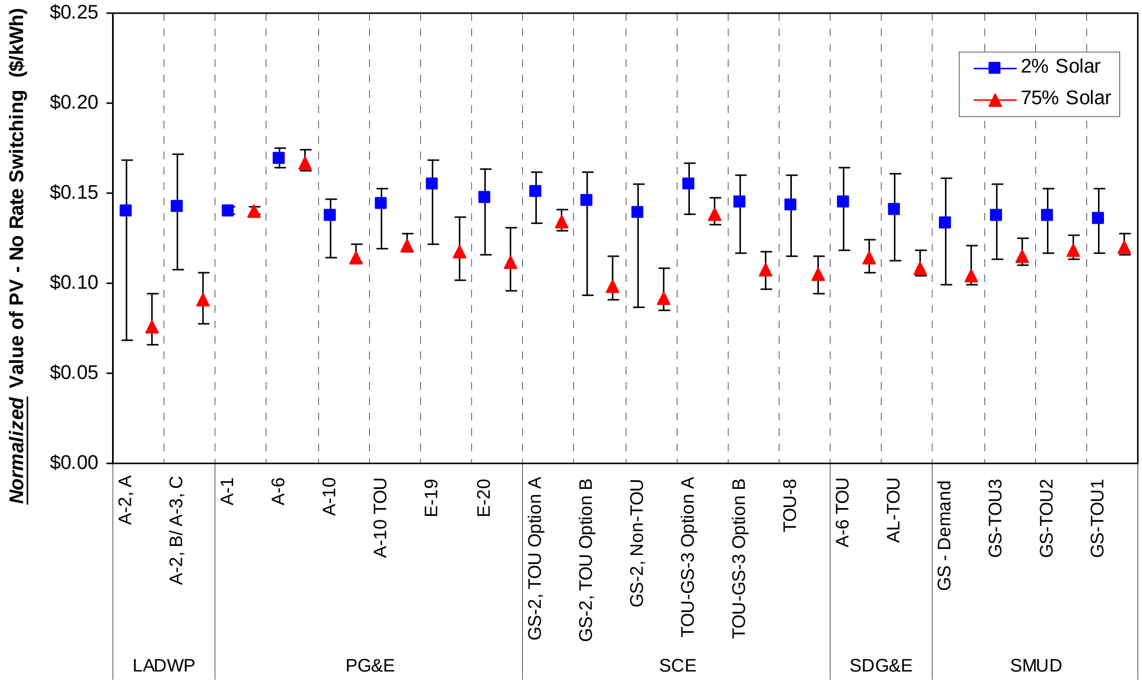


Figure 12. Histogram of Normalized Value of PV at Different Levels of Penetration

Figure 13 shows the distribution of the normalized value of PV for each rate, in terms of the median and 10th/90th percentile values (similar to Figure 7 in Chapter 4, which shows the un-normalized values). Once we control for the overall level of each rate (through normalization), it is apparent that the remaining differences among rates is notably less important at low levels of PV penetration than at high levels. At 2% PV penetration, for example, the range between the normalized median values of PV on each rate is smaller than the range of values within many individual rates. This indicates that, at low levels of PV penetration, the details of the rate structure are less important than factors related to customers namely, as we show later, customer load profile. Conversely, at 75% PV penetration, the range between the normalized median values of PV is much larger than the range of values within any single rate. As such, at higher levels of PV penetration, the details of the rate structure are more important in determining the value of PV than characteristics of the individual customers.[37]

[37] Expressed numerically, at a 2% PV penetration level, the median normalized value of PV ranges from $0.134/kWh (for SMUD's GS-Demand rate) to $0.170/kWh (for PG&E's A-6 rate). This range – equal to about 24% of the midpoint between the two values – represents the variation in the value of PV due solely to differences in rate structure, separate from the effects of differences in rate levels, customer load shapes, and PV production



Median value with error bars for 10th to 90th percentile range

Figure 13. Normalized Value of PV at Different Levels of Penetration, by Rate Structure

In the following three sections, we explore the particular characteristics of rate structures and individual customers that produce the remaining difference in the rate-reduction value of PV. Throughout the remainder of this chapter, we use normalized values to separately examine these characteristics without the confounding influence of rate levels. The reader is again cautioned to not interpret these normalized values as representing the actual value of PV.

5.3 Weighting Between Demand and Energy Charges

The relative size of demand-based charges, compared to energy-based charges, can have a sizable impact on the rate-reduction value of PV, as suggested by the results provided in Chapter 4. The *demand weight* of a particular retail rate is defined here as the proportion of total customer electric bills (pre-PV) that are made up of demand-based charges.

$$\mathit{Demand\ Weight} = \frac{\mathit{Portion\ of\ \ Bill\ \ from\ Demand\ \ without\ \ PV}}{\mathit{Total\ \ Bill\ \ without\ \ PV}} \times 100 \quad (\%)$$

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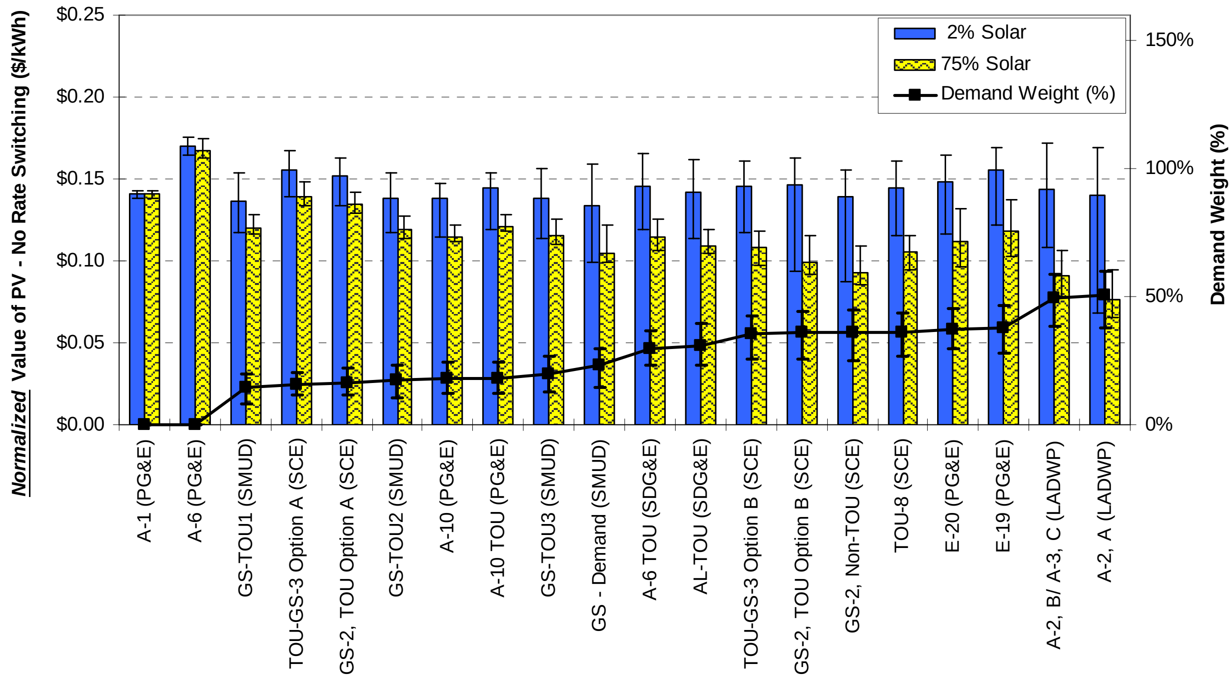
profiles. At a 75% PV penetration level, the median normalized value of PV across rates ranges from $0.077/kWh to $0.167/kWh, equivalent to about 74% of the midpoint between these values. Thus, at a very general level, we can say that, among commercial electricity rates in California, differences in rate structures alone can give rise to differences in the value of PV of 24% at 2% PV penetration and 74% at 75% PV penetration, for an average commercial customer.

The impact of a rate's demand weight on the normalized value of PV is powerfully illustrated by Figure 14. This figure presents data identical to that shown in Figure 12, with two exceptions: (1) we add a line that depicts the median demand weight (before PV installation) for each rate (along with 10th and 90th percentiles); and (2) we order the rates based on increasing demand weight.



Median value with error bars for 10th to 90th percentile range

Figure 14. Impact of Demand Charges on the Overall Normalized Value of PV, Under Different Rates

The figure shows that, when PV systems represent a small proportion of load, the existence of demand charges need not substantially degrade the value of PV. This is shown by the fact that, at 2% PV penetration, the normalized value of PV does not universally drop with increasing demand weight. A particular rate could have a demand weight anywhere between 0% and 50% and, on average, it would not significantly degrade the rate-reduction value of PV. In contrast, at 75% PV penetration, the median normalized value of PV unmistakably drops as the relative magnitude of demand-based charges increase. In the most extreme case, prior to PV installation, approximately one-half of an average commercial customer's total electricity bill under LADWP's A-2, A rate will derive from demand-based charges. With a PV system meeting 75% of a customer's annual load, a customer on this rate will earn only one-half of the (normalized) solar rate-reduction value as a customer on an energy-dominated rate (e.g., PG&E's A-6).

5.4 Determinants of the Value of Demand Charge Savings

The previous section suggests that commercial PV systems can often offer substantial savings on demand charges, at least when PV systems are small relative to annual customer load. At the same time, as PV penetration increases, we find that the rate-reduction value of PV degrades substantially among those rates that rely heavily on demand-based charges. Here we analyze these trends in more detail.

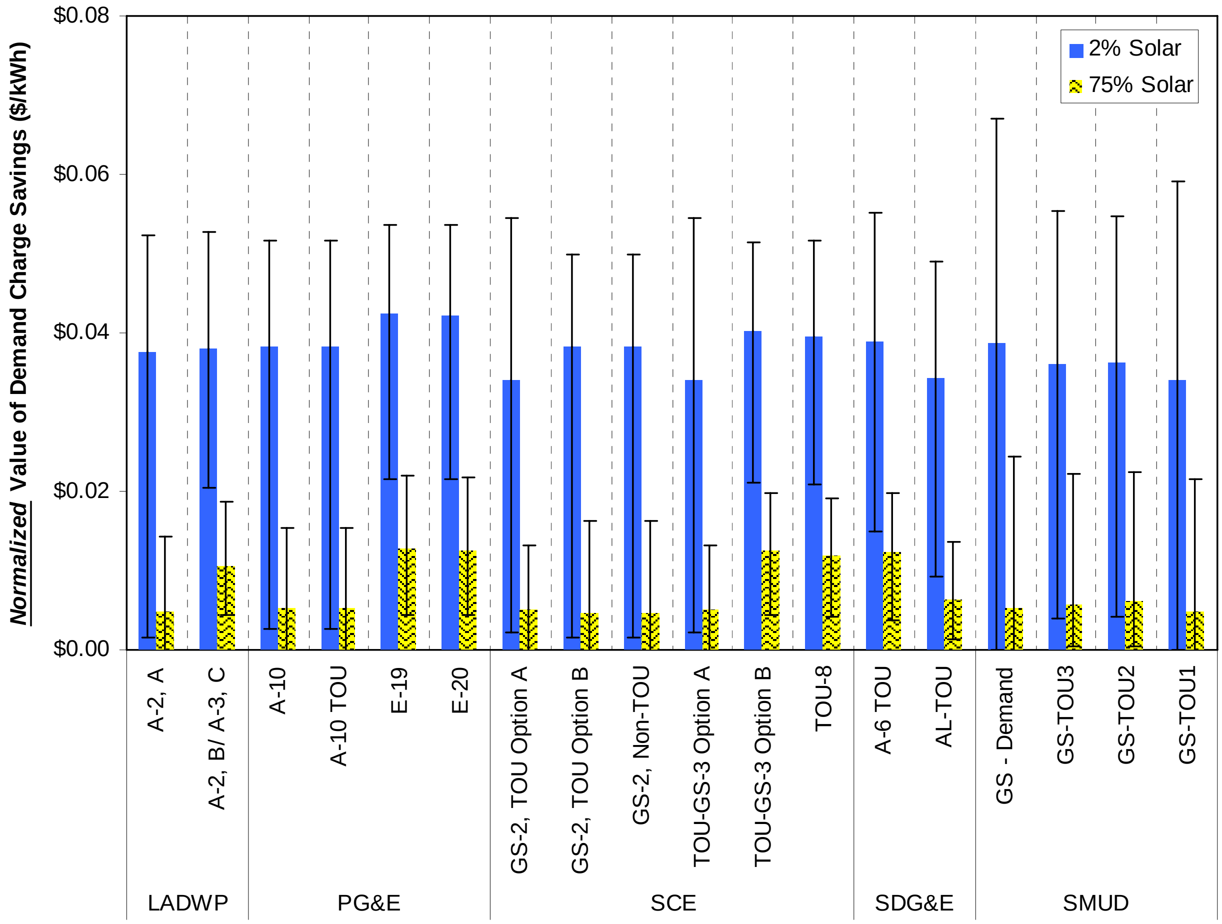
To begin, Figure 15 shows the distribution of the *normalized demand charge savings* for each rate (median, and $10^{th}/90^{th}$ percentiles), at 2% and 75% PV penetration. Normalization serves to control for differences in the magnitude of demand charges, as opposed to structural differences, and is calculated using a procedure analogous to that used to calculate the total normalized value of PV presented in Section 5.2. Specifically, the normalized value of demand charge savings is calculated by multiplying the actual value of demand charge savings (for a particular customer on a given rate) by the ratio of the median cost of demand charges across *all* 20 rates with demand charges to the median cost of demand charges on the given rate, as shown below:

$$Norm.\,VPV \;\; from \;\; Demand = \frac{VPV \;\; from \;\; Demand}{Med.\,COE \;\; from \;\; Demand \;\; for \;\; Rate} \times Overall \;\; Med.\,COE \;\; from \;\; Demand$$

Confirming earlier results, two basic conclusions emerge from this figure:

- for a given rate, the value of demand charge savings varies substantially across customers, reflecting differences in PV production profiles and customer load shapes; and
- across all rates with demand charges, the per kWh value of demand charge savings declines precipitously with increasing PV penetration levels.

By virtue of using *normalized* values, Figure 15 also allows us to directly isolate, for the first time, the differences in PV-induced demand charge savings across rates associated specifically with differences in demand charge structure. At 2% PV penetration, for example, the median normalized value of demand charge savings ranges from \$0.033/kWh to \$0.041/kWh across rates, a difference of about 22% relative to the midpoint. At 75% PV penetration, the range is similar in absolute magnitude, but much larger in percentage terms, with the normalized value of demand charge savings for some rates effectively twice that for other rates. These variations are driven solely by difference in the specific structural design of the demand charges in our rate sample. In comparison, variations in demand charge savings associated with differences in customer load shapes and/or PV production profiles, reflected by the width of the percentile bands for each rate, are notably greater. This suggests that one or both of these customer-specific factors has a much more significant impact on the value of demand charge savings than any issues related specifically to the structure of the demand charge itself.



Median value with error bars for 10th to 90th percentile range

Figure 15. Normalized Value of Demand Charge Savings

In the remainder of this section, we explain trends in PV-induced demand charge savings by exploring in detail the influence of four specific factors: the structure of the demand charge, the PV penetration level, the shape of the PV production profile, and the customer load profile.

5.4.1 Demand Charge Design

Demand charges come in a number of variants, differing in both the measure of customer demand and whether or not demand charge rates vary over the course of the year. Four basic types of demand charges are represented among the rates in our analysis.

- **Annual Fixed:** These demand charges are based on maximum customer demand over the past 12-month period, irrespective of when that peak occurs, and the $/kW demand charge rate is fixed at a single level throughout the year.
- **Monthly Fixed:** These demand charges are based on maximum customer demand during the monthly billing period, irrespective of when the peak occurs within that month, and the $/kW demand charge rate is fixed at a single level throughout the year.

- **Monthly Seasonal:** These demand charges are based on maximum customer demand during the monthly billing period, however, the $/kW demand charge rate varies seasonally, with a higher rate during summer months.
- **Time-of-Day (TOD) Seasonal:** These demand charges are based on maximum customer demand during one or more specific TOD periods, with different $/kW demand charge rates for different TOD periods; among the rates in our analysis, the TOD demand charge rates also vary by season.

Before analyzing the impact of PV on demand charges directly, it is first useful to consider the impact of those systems on customer demand, itself – in particular, on customers' maximum annual demand, maximum monthly demand, and maximum monthly demand during summer on-peak periods. These results are presented in Figure 16, Figure 17, and Figure 18, in terms of the *effective capacity* of the PV system, defined as the reduction in peak customer load relative to the size of the PV system (e.g., an effective capacity of 25% implies that a 100 kW PV system would reduce peak customer load by 25 kW).[38] The $10^{th}/90^{th}$ percentile bands in these figures reflect variations in customer load shapes and PV production profiles among our 24-sample dataset.

$$Effective\ Capacity = \frac{Reduction\ in\ Customer\ Peak\ Demand\ (kW)}{PV\ Capacity\ (kW)} \times 100\ (\%)$$

Collectively, these three figures show that the effective capacity of PV systems can range anywhere from over 80% to slightly less than 0%,[39] depending on the measure of customer demand, the PV penetration level, and the customer load and PV production profiles. This wide range should raise doubts about the veracity of simple generalizations regarding the ability of commercial PV systems to reduce customer peak demand. Clearly, there is no single value that is broadly applicable across the range of potential circumstances.

One general trend evident in all three figures, however, is that effective capacity declines – in some cases quite dramatically – with increasing PV penetration levels, mirroring the corresponding decline in the value of demand charge savings with PV penetration level previously noted. The physical basis underlying this trend is that, at higher levels of PV penetration, peak loads shift to times during which PV production is minimal or non-existent. In the limit, once a PV system pushes the customer's monthly or annual peak demand to non-daylight hours, any further increase in system capacity has no value in reducing demand charges assessed on monthly or annual peak demand. Similarly, for demand charges based on maximum monthly demand during the summer peak TOD period, increases in PV penetration eventually push the maximum peak period demand to the end of the TOD period, when PV production is either relatively low or zero, depending on when the peak period ends.

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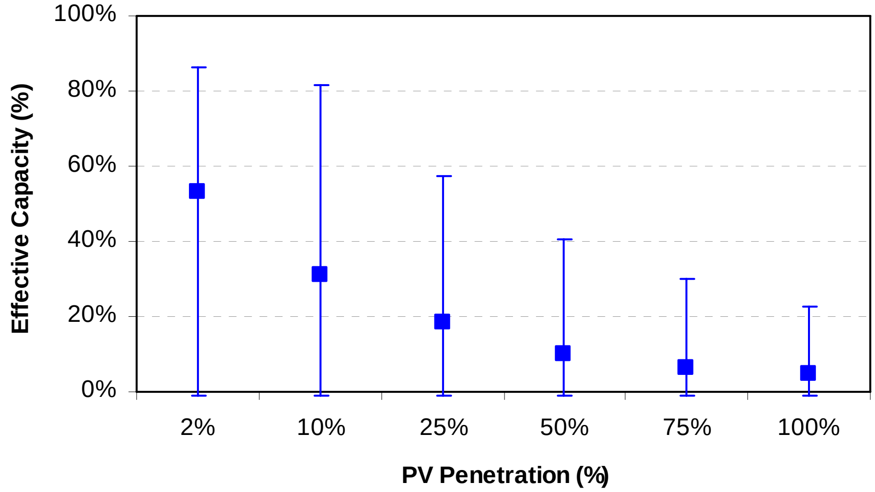
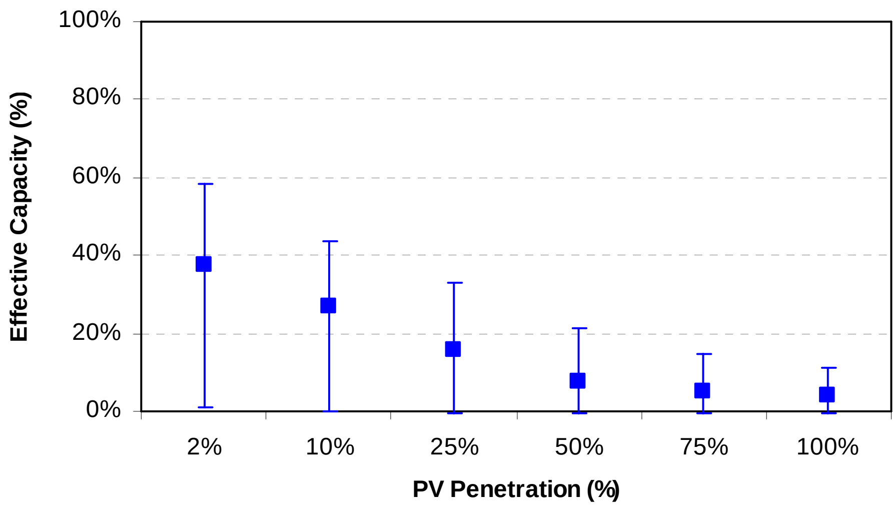
[38] The size of the PV system is based on the maximum power produced by the PV system over the entire dataset, which may differ from manufacturer system ratings.

[39] In some cases, maximum customer demand occurs at a time when no PV power is being produced and the inverter is consuming a small amount of parasitic power. In these rare cases, occurring mostly for facilities that have demand peaks at night, the peak demand might be slightly increased due to the installation of the PV system.



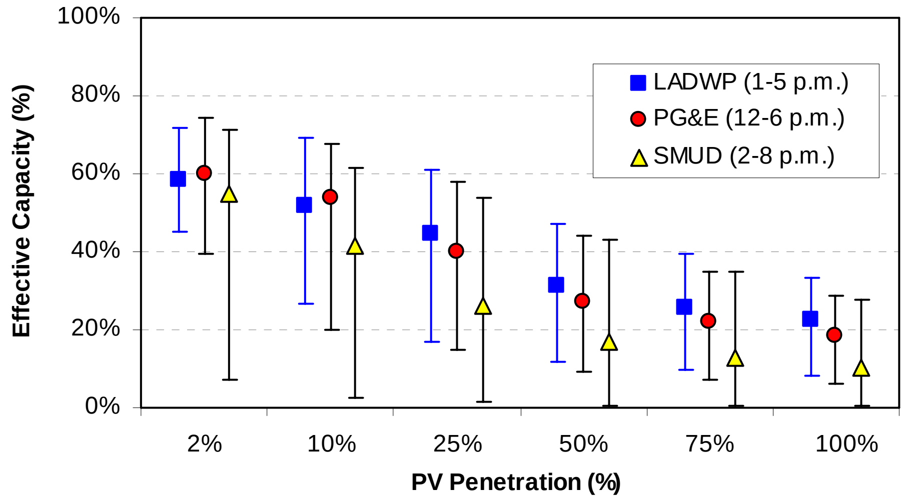
Median value with error bars for 10th to 90th percentile range

Figure 16. Effective Capacity of PV Systems: Annual Peak Reduction



Median value with error bars for 10th to 90th percentile range

Figure 17. Effective Capacity of PV Systems: Average Monthly Peak Reduction



Median value with error bars for 10th to 90th percentile range

Figure 18. Effective Capacity of PV Systems: Average Monthly Summer Peak Period Reduction

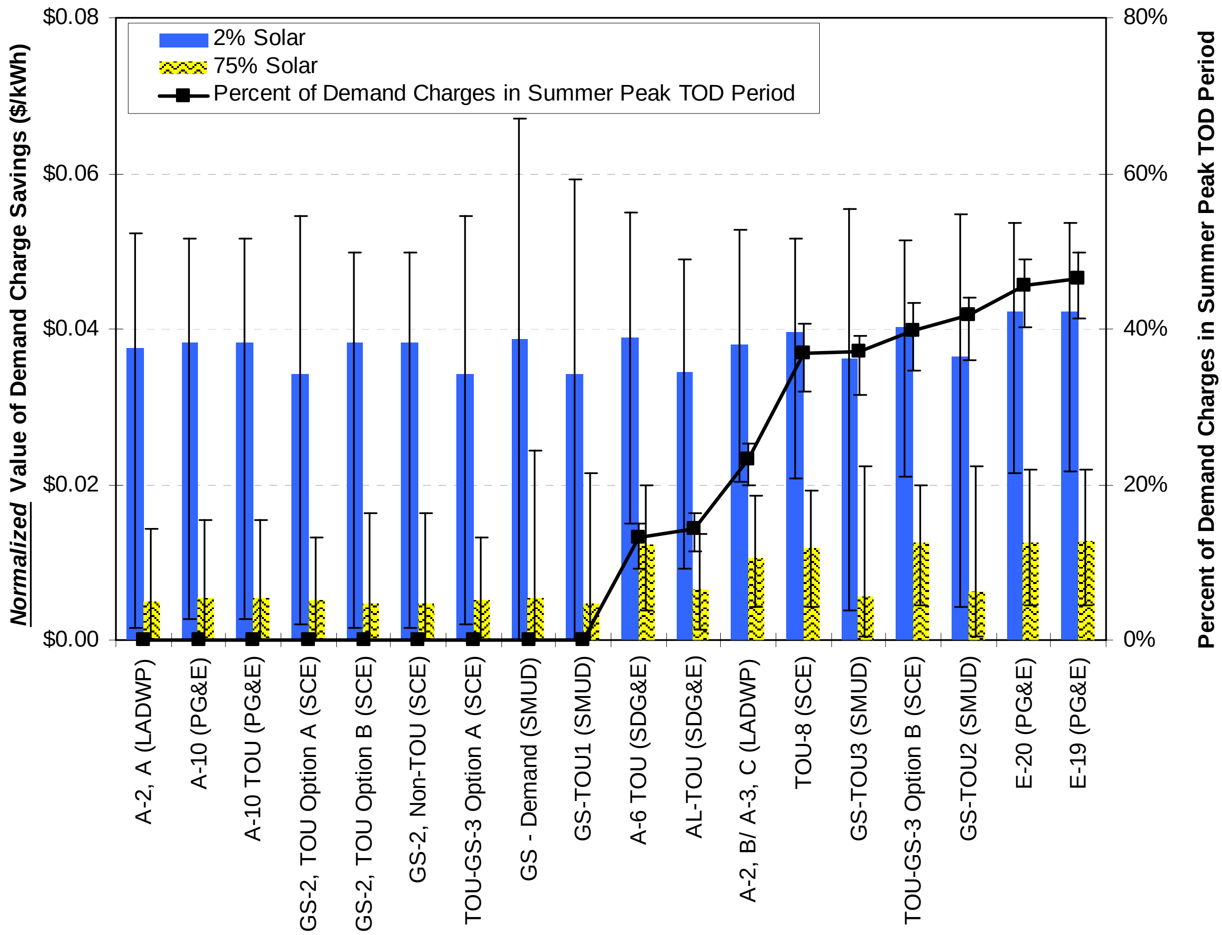
Notwithstanding the general similarities, important differences among the figures can also be discerned. When defined as annual 15-minute peak load, there is considerable variability in the effective capacity of PV across our 24 PV/load datasets, and the median value drops rapidly as PV penetration levels increase (Figure 16). When peak load is defined as monthly 15-minute peak load, on the other hand, the median effective capacity of PV is somewhat lower than for the annual peak load because PV systems produce less electricity during certain (winter) months (Figure 17). The 10th/90th percentile bands, however, are narrower, showing that the consistency of peak reductions is greater when considering monthly averages than when annual peak reductions are estimated. This is to be expected because re-establishing maximum demand on a monthly basis lessens the annual impact of one-time or otherwise infrequent events.

Finally, Figure 18 summarizes the effective capacity of PV systems in our dataset based on reductions in peak customer load during the summer peak TOD period. Since each utility defines this period differently, we show separate results using three utilities' peak TOD definitions. [40] We see that, when based on LADWP's or PG&E's summer peak period (which end at 5 p.m. and 6 p.m., respectively), the effective capacity of PV is somewhat larger and much less variable than when based on reductions in monthly or annual peak load (Figure 16 and Figure 17). In addition, this value does not decline as dramatically with increasing PV penetration as does the effective capacity of PV when based on reductions in monthly or annual peak load. The same conclusions, however, cannot be said when SMUD's definition of the summer peak period is used. This is because SMUD's peak period ends at 8 p.m.; thus, for any given PV penetration level, the customer's maximum summer peak TOD load is much more likely to occur during hours when the PV system is producing little or no output. For similar

[40] We do not separate the effect of the different hourly time periods used in the definition of the TOD period from the effect of the different months considered under these definitions. We expect that the dominant reason for the difference in effective capacity shown above relates to differences in hourly time periods. Nonetheless, differences in the months included in the peak summer TOD period also exist: summer includes the months of June to October for LADWP, May to October for PG&E, and June to September for SMUD.

reasons, at PV penetration levels greater than 10%, we see that the effective capacity is lower for PG&E's summer TOD period definition than for LADWP's. In short, these figures show that the ability of PV systems to reduce peak customer loads is greatest and most consistent across customers when one focuses on the maximum load during summer peak TOD periods, provided that the period does not extend into non-daylight hours

Armed with these findings, we are now in a position to understand how differences in the composition of demand charges across rates explain some of the observed variation in PV-induced demand charge savings. Figure 19 again presents the *normalized* value of demand charge savings for each rate, except that the rates are now ordered according to the size of the summer peak TOD demand charges (before PV) as a percent of total demand charges. From this figure, we see that, at a 75% PV penetration level, the median value of PV-induced demand charge savings tends to be greatest for those rates with a larger portion of demand charges assessed based on maximum summer peak period demand. The same is true, though in a less pronounced fashion, at a 2% PV penetration level.[41]



Median value with error bars for 10th to 90th percentile range

Figure 19. The Impact of Summer Peak TOD Demand Charges on Normalized Demand Charge Savings

[41] These gains are less significant for SMUD's rates, since the utility's summer peak TOD period ends at 8 p.m.

5.4.2 PV Production Profile

Though demand charge design clearly impacts the value of PV, the extraordinarily wide variation in demand charge savings for each individual rate (at a given PV penetration level) shows that the combined effect of differences in PV production profiles and customer load profiles must also play a dominant role in the ability of PV systems to offer demand charge savings. We would expect the specific pattern of PV production to have some effect on the value of demand charge savings, given the time-varying building load and the time-varying nature of some demand charges. In addition to impacts associated with differences in the typical daily PV production profile (e.g., related to geographical location, panel orientation, and shading), we might also expect some impact associated with periodic “drop-outs” in PV production (e.g., related to passing clouds or occasional equipment failure).

To isolate the impact of differences in PV production profiles on the value of demand charge savings, we mixed-and-matched load and PV production data across sites. Specifically, we selected five customer load datasets, each representative of different types of load shapes: one customer with a flat load profile, one with an inverted load profile, and three customers whose loads profiles have an afternoon peak. We then combined each of these five load datasets with each of the PV production datasets from the other sites, yielding a total of 24 paired datasets for each of the five customer loads. We evaluate the demand charge savings for these paired datasets under two PG&E rates: A-10, which has a single, relatively small demand charge assessed on monthly peak demand; and E-20, which has a demand charge assessed on monthly peak demand as well as a substantial TOD-based demand charge. These two rates, in some sense, represent “boundary cases.”

Figure 20 presents the range between the 10th and 90th percentile values for each of the five customer load profiles. These values solely reflect differences in the PV production profiles within our dataset. As the figure shows, the percentile range is very narrow, regardless of PV penetration level, customer load shape, and retail rate. As such, we conclude that the influence of the specific PV production profile on demand charge savings is quite small, compared to the total variation in normalized demand charge savings for each rate. For example, for PG&E’s A-10 rate and at a 2% PV penetration level, the width of the percentile band averages just $0.005/kWh across the five customers shown in Figure 20. In comparison, the percentile band for the distribution associated with PG&E’s A-10 rate and the original 24 customer load/PV production datasets, shown in Figure 15, is approximately ten times larger.

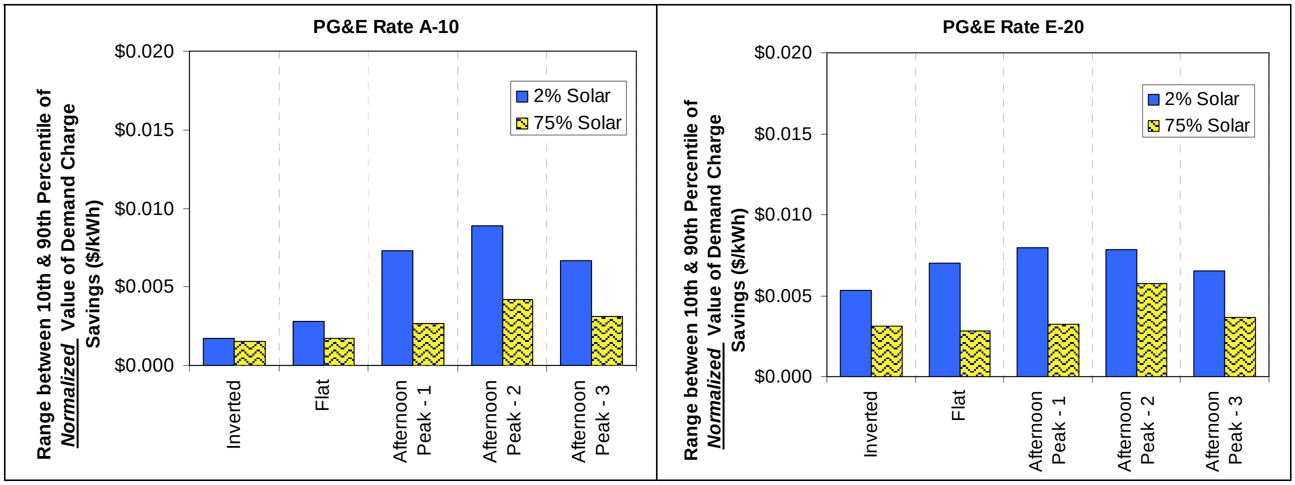


Figure 20. Variation in Normalized Demand Charge Savings Due to Differences in PV Production Profile

5.4.3 Customer Load Shape

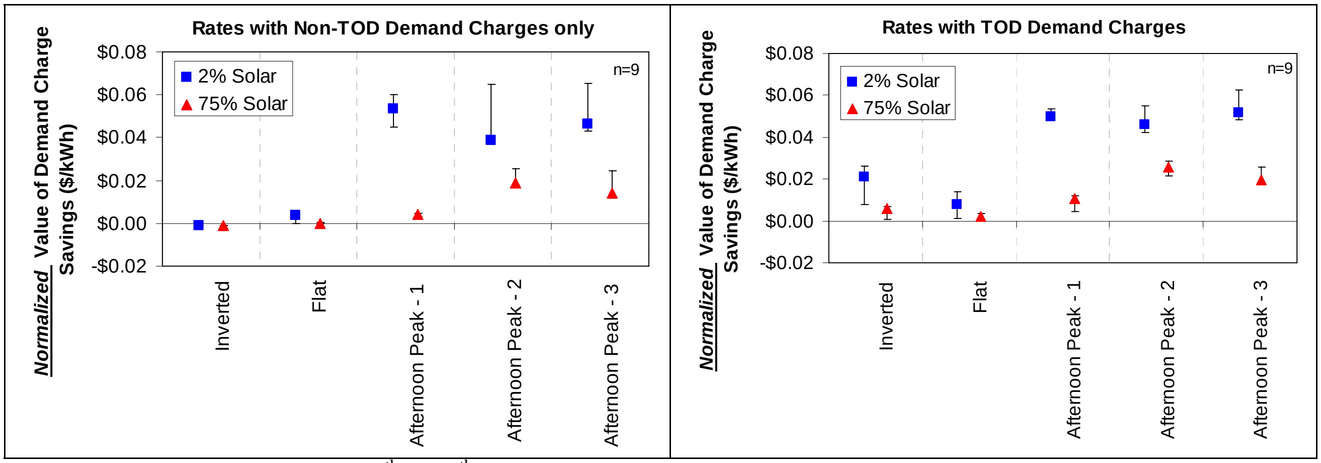
If differences in PV production profiles have a relatively minor impact on demand charge savings, we can infer that variations in demand charge savings for a given rate and PV penetration level are due primarily to differences in customer load shape. Here we examine in greater detail how and why customer load shape affects the value of PV-induced demand charge savings.

The basic reason that customer load shape would affect the value of demand charge savings is relatively straightforward: the value of demand reduction depends, in large part, on the correlation of the time-dependent performance of the PV system to the time-dependent load of the building. Most obviously, customers with peak demands during the evening hours will often earn little or no demand charge reductions from installing PV. However, if customers with high demand in the evening hours are on rates with time-of-day demand charges, a PV system may reduce demand during those on-peak times, thus reducing at least a fraction of the demand charges.

Figure 21 presents the normalized value demand charge savings (median and $10^{th}/90^{th}$ percentiles) for the five representative customers introduced previously, this time across all 18 rates with demand-based charges. To illustrate the interrelationship between customer load shape and demand charge structure, we have segmented the 18 rates into two groups: those that contain TOD demand charges and those that that do not. The figure leads to the following conclusions:

- In general, demand charge savings vary greatly across customer load shapes.
- Customers with afternoon peak loads can earn substantial demand charge savings, regardless of the design of the demand charges, especially at low levels of PV penetration.
- Demand savings for customers with flat or inverted load profiles are generally negligible among rates without TOD-based demand charges, but somewhat greater savings are possible

among rates with TOD-based demand charges (though still notably less than is typically earned by customers with afternoon peaks).



Median value with error bars for 10th to 90th percentile range

Figure 21. Normalized Demand Charge Savings for Different Load Shapes with Rates with and without TOD Demand Charges

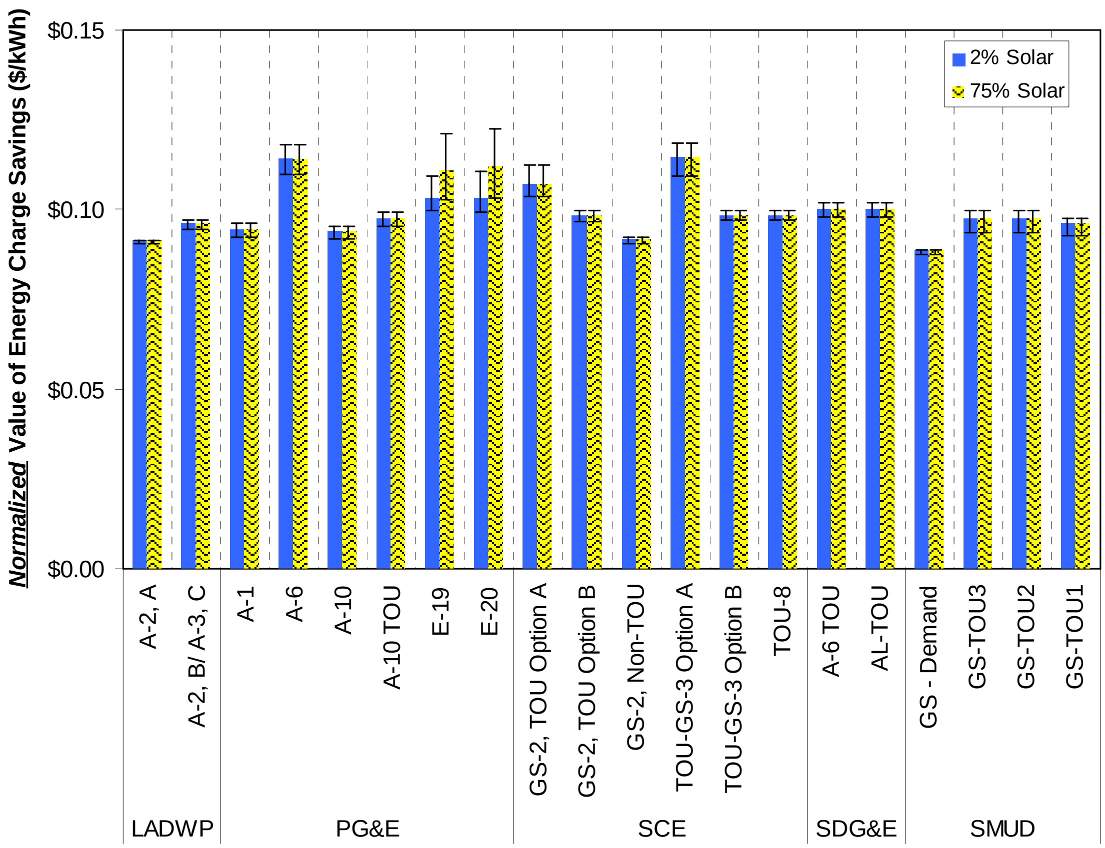
5.5 Determinants of the Value of Energy Charge Savings

Just as the design of demand-based charges affects the rate-reduction value of PV, so to does the design of energy-based charges. Figure 22 presents the distribution of *normalized energy charge savings* for each rate (median and 10th/90th percentiles), calculated analogously to the normalized demand charge savings presented earlier.[42] Three key findings are supported by this figure.

- First, differences in normalized energy charge savings among rates clearly indicate that the specific structure of energy charges can have an impact on PV-induced energy charge savings of as much as $0.02/kWh.
- Second, for most rates, the width between the 10th and 90th percentile bands is quite narrow, indicating that the specific pattern of PV production has a relatively modest impact (less than $0.01/kWh) on the *per kWh* value of energy charge savings in most instances.
- Third, normalized energy charge savings generally do not vary across PV penetration levels, because the energy-based credits (on a $/kWh basis) earned under net metering do not depend on the magnitude of PV production or its coincidence with building load.[43]

[42] The normalized value of energy charge savings is calculated by multiplying the actual value of energy charge savings (for a particular customer on a given rate) by the ratio of the median cost of energy across *all* rates to the median cost of energy on the given rate. This procedure is analogous to that used to calculate the normalized value of PV presented in Section 5.1, and allows us to specifically control for differences in the size of energy charges.

[43] The only exceptions are PG&E's E-19 and E-20 rates, for which the normalized value of energy charge savings actually increases with penetration level. This is due to the fact that both rates have an "Average Rate Limiter" provision, which caps the total cost of demand and energy charges at a fixed $/kWh rate in summer months. Due to the way that this provision is applied, the larger the PV penetration rate, the more likely the rate limiter cap will be reached, and the lower the utility bill will be. The rate impacts of this provision depend on the customer load shape (in addition to the profile of PV production), which is why E-19 and E-20 have relatively wide percentile bands.



Median value with error bars for 10th to 90th percentile range

Figure 22. Normalized Value of Energy Charge Savings

Below, we explore two specific differences in energy charge structure that underlie these observations: the basic type of energy charge and, for TOU-based charges, the spread between peak and off-peak prices. Because, as shown above, the level of PV penetration does not typically impact energy charge savings, we present results based on a 2% PV penetration for the remainder of this section.

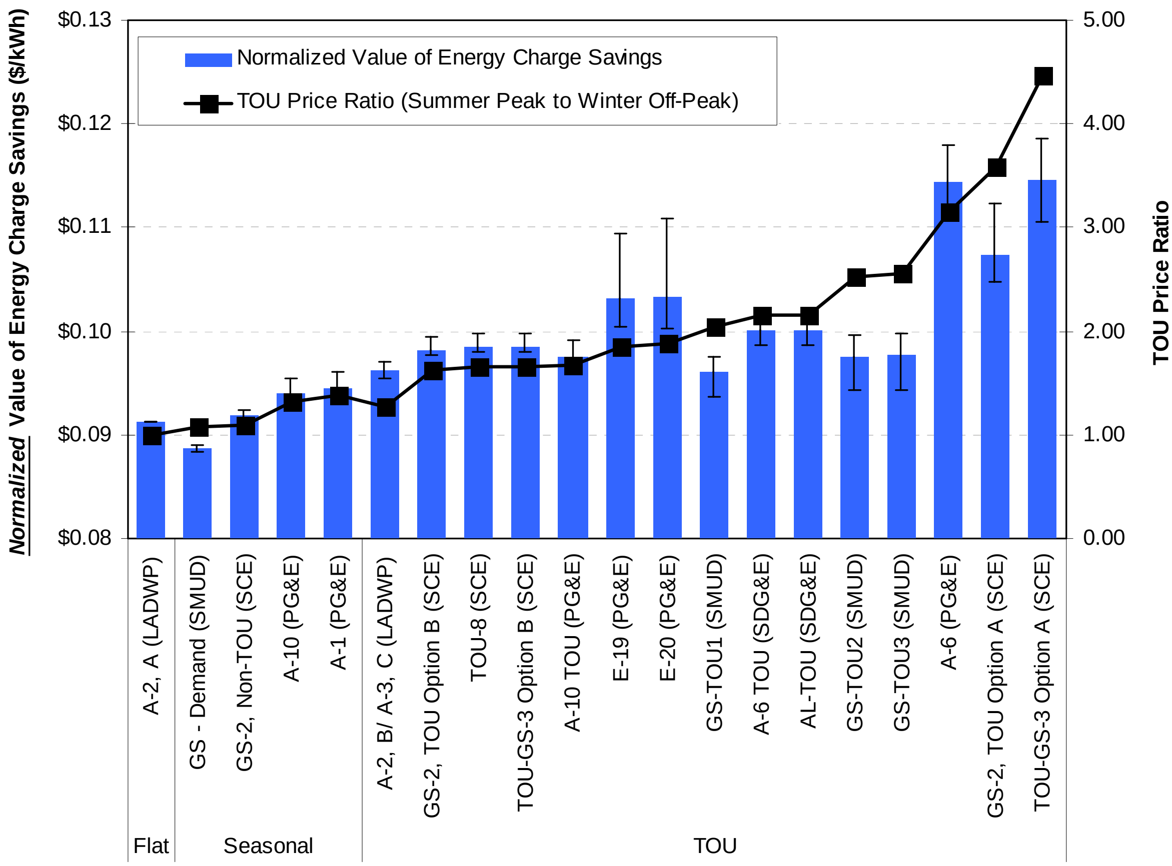
The rates represented among our sample include three basic types of energy charges:

1. flat energy charges, which are constant at all times throughout the year;
2. seasonal energy charges, which vary only by season (winter or summer); and
3. TOU energy charges, which vary by time-of-day and, in some cases, also by season.[44]

Figure 23 summarizes our findings on the impact of energy charge structure on the rate-reduction value of commercial PV systems. The figure presents the normalized value of energy charge savings for each rate (the same information as provided in Figure 22), but groups the rates according to the type of energy charge used and lists the rates in order of increasing summer peak to winter off-peak price ratio. In the case of the seasonal rates, the value of this ratio is

[44] Two other types of energy charge structures, not represented within our analysis, are tiered (inclining or declining) block charges and hourly energy charges (e.g., real time pricing).

simply the summer season rate divided by the winter season energy rate. The flat rate has a ratio of one. Note that the y-axis in the figure begins at $0.08/kWh, rather than $0/kWh, to more clearly highlight differences among the rates.



Median value with error bars for 10th to 90th percentile range

Figure 23. Summary of Rate Structure Impacts on Energy Charge Savings

As the figure shows, the normalized value of energy charge savings is generally greater under TOU-based energy charges than for those with seasonal or flat energy charges, as we would expect, given that TOU rates provide a higher credit for PV production during afternoon periods when PV production tends to be the greatest. In particular, TOU-based energy rates with relatively little spread between peak and off-peak prices offer approximately 5-10% greater (less than roughly $0.01/kWh) energy charge savings than do rates with seasonal or flat energy charges.

The figure also shows that the normalized value of energy charge savings varies more significantly among TOU-based energy charges, than between TOU and non-TOU rates, in part due to differences in the TOU price ratio. For the TOU-based rates with the highest peak to off-peak price ratios, PV-induced energy charge savings are approximately 15% greater ($0.015/kWh) than those with the least differentiation. Also evident in Figure 23 is that the width of the percentile bands tends to increase with the price ratio, suggesting that the impacts of particular PV production profiles on energy charge savings are most significant for TOU rates with a large differential between peak and off-peak prices.

5.6 Summary of PV Value Drivers

As shown throughout this chapter, much of the variation in the value of PV presented in Chapter 4 can be explained by differences in rate levels, rate design, customer load profiles, and PV system size relative to building load. Although the details of the PV production profile have some impact on the per-kWh value of PV-provided rate savings, our results find that that effect is relatively modest, at less than $0.01/kWh in most instances.

To compare the *relative* impact of each of these factors in a more integrated fashion, we fit a linear regression model to the data. Though we previously explored each variable independently, the model allows for a better assessment of the relative effect of each factor. The model includes five independent variables:

- the median cost of electricity for each rate;
- the median amount of demand-based charges for each rate (i.e., demand weight);
- the median portion of demand charges that are summer-peak TOD-based for each rate;
- the peak/off-peak price spread for TOU-based energy charges for each rate (this variable effectively captures peak/off-peak prices for TOU-based energy charges, as well as differences between TOU-based charges and annual or seasonal energy charges); and
- a load shape variable that characterizes the degree to which a customer's load profile is summer-peaking (see Section 3.2 for a definition of this load shape variable).

One limitation of this analysis is that the regression model involves the use of independent variables that are derived from the same set of data used to calculate the dependent variable, the value of PV. To minimize the chance of spurious relationships due to the use of the same data in calculating the dependent and independent variables we use median values calculated from the whole set of customers to characterize some of the general features of the 20 different retail rates. Nonetheless, the results presented below are intended primarily for illustrative purposes, and the exact numerical values and levels of significance should be taken with caution.

The resulting regression model, at both 2% and 75% PV penetration, is presented in Table 2. As shown, the five variables included in the model explain the majority of the variation in the rate-reduction value of PV. The R-squared values show that these five variables account for 90% of the variation in the value of PV at the 75% PV penetration level, and 73% of the variation at the 2% PV penetration level. Additionally, all five of the variables are statistically significant at a greater-than 95% confidence level.

Positive parameter estimates in Table 2 indicate that an increase in the value of the independent variable will increase the value of PV. For example, the positive parameter estimate for the median cost of electricity indicates that the value of PV is greater for rates that have a higher median cost of electricity, at both 2% and 75% PV penetration. In contrast, the negative parameter estimate for the median demand weight indicates that the greater the demand weight for a given rate, the lower the value of PV. All coefficients in the model are of the expected sign, confirming the basic findings relayed earlier in this chapter.

Table 2. Multiple Linear Regression Model of the Rate-Reduction Value of Commercial PV

Multiple Linear Regression with Value of PV ($/kWh) as Dependent Variable, n=480		2% Penetration		75% Penetration	
Coefficient of Determination (R squared) [a]		0.734		0.903	
Term	**Input Range** [c]	**Parameter**	**Significance (%)** [b]	**Parameter**	**Significance (%)**
Median Cost of Electricity ($/kWh)	0.0953 → 0.1616	1.149	>99.99%	1.001	>99.99%
Median Demand Weight	0.0 → 0.504	-0.020	99.20%	-0.104	>99.99%
TOU Price Spread	1.0 → 4.467	0.006	>99.99%	0.006	>99.99%
Median Portion of Demand from Summer Peak TOD Charges	0.0 → 0.465	0.011	98.10%	0.006	>99.99%
Load Shape	0.5871 → 1.9097	0.027	>99.99%	0.014	>99.99%
Intercept ($/kWh)		-0.054	>99.99%	-0.020	>99.99%

[a] The coefficient of determination describes how well the model is able to account for variations in the Value of PV; 1.0 being a perfect model.

[b] The significance indicates the probability that a particular parameter is different than zero

[c] The input range is the distance between the data point that gives the lowest and highest value of PV for each variable

The parameters of the regression model can also be used to determine the expected change in the value of PV based on the range of each of the independent variables from the 20 rates and 24 customers. The results of that calculation are shown in Figure 24.

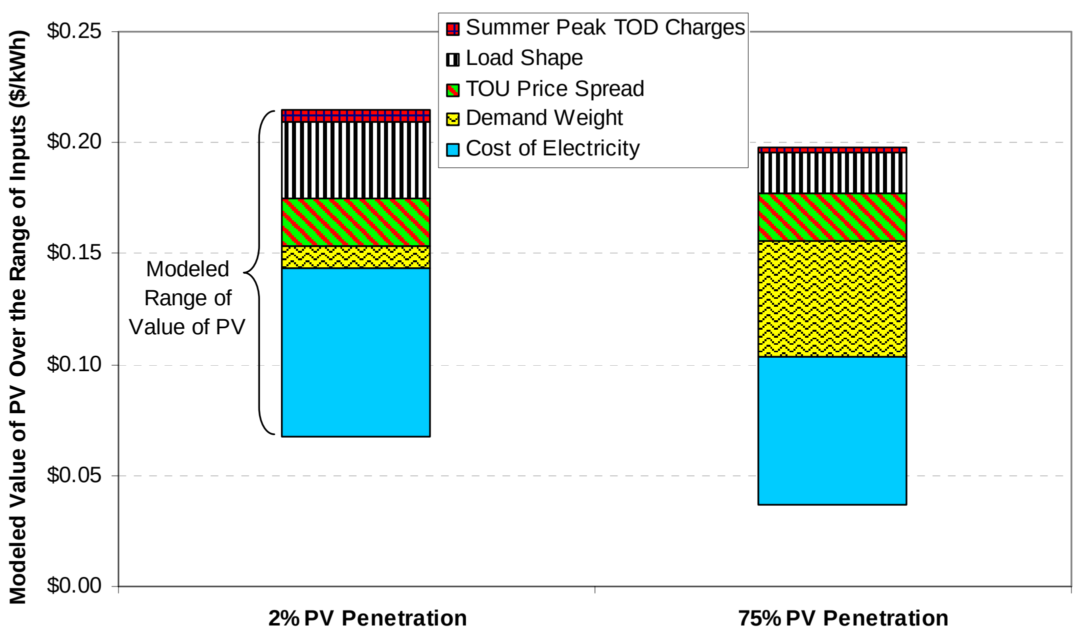


Figure 24. Modeled Change in the Value of PV Based on the Range of Each Factor

The height of each bar-segment in Figure 24 reflects the (modeled) difference in the value of PV between the data point that leads to the lowest and the highest value of PV for each variable, based on the regression model shown in Table 2. The height of the segment therefore reflects the combined effect of the range of input values and the sensitivity of the value of PV to changes in those input values. The bar-segments are stacked beginning with the lowest value of PV calculated using the extremes of each variable. The highest value of PV at the top of the stack is then the value of PV calculated from the opposite extreme of the variables.

At both levels of PV penetration the most important factor is found to be the median cost of electricity on the rate, or the rate level. Rates that generally have a high cost will also have a high value of PV, if the customer remains on the same rate before and after PV installation. The coefficient value of roughly 1 indicates that every $0.01/kWh increase in the median cost of electricity will, on average, yield an increase of the value of PV of a similar magnitude.

The next most important factor, at high levels of PV penetration, is the demand weight. At high levels of PV penetration, the demand weight is nearly as important as the cost of electricity. As we demonstrated earlier, rates with high demand charges almost always lead to lower values of PV, at high PV penetration levels. This reduction in the value of PV is due to the significantly diminished ability of PV to offset demand charges as PV system size, relative to load, increases. Based on the results in Figure 24, a rate with a median demand weight of 50% will value PV at $0.052/kWh *less* than an otherwise similarly structured rate with 0% demand weight, at 75% PV penetration. At low levels of PV penetration, the demand weight has a smaller effect on the value of PV because PV systems are better able to reduce demand-based charges when those systems are small relative to customer load.

The only variable in the model that is unique to each customer is the load shape parameter, which is found to be the second most important variable at low levels of PV penetration. The positive parameter estimate shows that, in general, the more energy a customer consumes during the summer peak period, the greater the value of PV. As discussed earlier, this is because customers with summer-afternoon peaking loads are better able to offset demand charges with PV installations. The load shape parameter has a greater impact on the value of PV at 2% penetration than it does at 75% penetration because, at higher levels of PV penetration, the ability of PV to reduce demand charges is diminished regardless of customer load shape.

The third most important variable, at both levels of PV penetration, is the TOU energy-charge price spread. The parameter estimates for this term indicate that rates with a high ratio of summer peak to winter off-peak energy charges have a similar effect of increasing the value of PV at both 2% and 75% PV penetration. TOU-based energy rates that place particular emphasis on peak prices can clearly benefit PV. The results in Figure 24, for example, indicate that a rate with a TOU price spread of 4.47 will, on average, lead to a $0.021/kWh increase in the value of PV in comparison to a rate with flat energy charges.

The least important variable included in the model is the median portion of demand charges that come from summer-peak-based charges. Earlier analysis in this chapter showed that PV is more likely to offset TOD-based demand charges than monthly or annual demand charges for customers with flat or inverted load shapes. The positive parameter estimate for this variable at both 2% and 75% penetration confirms that demand charges that place more value on reductions in summer peak loads lead to a higher value of PV. The somewhat lower significance level and the small parameter estimate, however, indicate that the relationship between summer peak demand charges and the value of PV is relatively weak, especially at high levels of PV penetration.

To conclude, this analysis shows that the value of PV will generally be greatest for rates with high overall costs of electricity, small or non-existent demand charges, high summer peak to winter off-peak energy price spreads, and demand charges that are based on customer load during the summer peak period. In general, the value of PV will also be greater for those customers that consume a disproportionately high amount of energy during the summer peak period.

6. The Value of Commercial PV with Rate Switching

The analysis in the previous chapters assumed that customers would remain on the same electricity tariff both before and after the installation of their PV system. This chapter relaxes that assumption, given the fact that customers are often able to select from several rates to obtain the lowest bill. Unlike previous chapters, here we assume that customers choose the lowest cost (i.e., optimal) rate both before and after installing their PV system, recognizing that the best rate after the installation of the PV system may differ from the best rate before installation.

In some cases, the value of PV may be overstated if it is assumed that a customer must be on the same rate before and after the installation of their system. This may occur if a particular retail rate is generally unattractive for customers without a PV system (i.e., creates a greater bill than other rates) but more attractive with a PV system. In other cases, allowing for rate switching can increase the value of PV. This would be the case for retail rates that are relatively inexpensive without PV but then become more expensive relative to other rate options once a PV system is installed.

We explore these issues in further detail in this chapter. First we show which of the available rates are the least cost options assuming customers choose among available rates in each customer size class, both with and without PV. We then examine specific cases in which customers would chose to switch between rate structures to determine the characteristics of a "PV-friendly" rate. Next, we compare the value of PV across each customer size class at both 2% and 75% PV penetration. Finally, we compare the value of PV with rate switching to the value of PV without rate switching. Throughout, we continue to assume that net metering is available.

6.1 Optimal Rate Selection

For each of the five utilities covered in this report, the specific set of rate options available to a given customer depends on the customer's peak demand (see Table 3). In total, there are fifteen customer size categories that offer different groups of rates among which a given customer could potentially choose, depending on its utility and the customer's peak demand. Of these fifteen customer size categories, seven only have a single rate that is available, and rate switching is therefore not an option.

In the following analysis, we use all 24 customer load shapes, irrespective of the actual magnitude of customer demand, to determine the optimal rate within each of the eight customer size categories that offer multiple rate options, before and after the installation of the PV system.[45] As noted in Chapter 3, different rates may have different fixed customer charges and, therefore, the value of PV with rate switching accounts for any change in fixed customer charges. The fact that fixed customer charges are a small portion of total electricity bills in California, however, as shown in Figure 10, means that changes in fixed customer charges will have a relatively small impact for all of the 24 load shapes we use in the analysis.

[45] For simplicity, we assume that a customer faces the same set of rate options before and after PV installation. In reality, that may not be the case if the PV installation substantially reduces a customer's peak demand.

Table 3. Rate Options Available, Depending on Customer Size

Rate Options

Utility	Customer Size	Rate Options Available
LADWP	30-100 kW	A-2, A and A-2, B
	>100 kW	A-2,B/ A-3,C
PG&E	<200 kW	A-1; A-6; A-10; A-10 TOU; and E-19
	200-500 kW	A-6; A-10 TOU; and E-19
	500-1000 kW	E-19
	>1000 kW	E-19 and E-20
SCE	20-200 kW	GS-2, TOU Option A; GS-2, TOU Option B; and GS-2, Non-TOU
	200-500 kW	TOU-GS-3 Option A and TOU-GS-3 Option B
	>500 kW	TOU-8
SDG&E	<500 kW	AL-TOU
	>500 kW	AL-TOU and A-6 TOU
SMUD	20-300 kW	GS-Demand and GS-TOU3
	300-500 kW	GS-TOU3
	500-1000 KW	GS-TOU2
	>1000 kW	GS-TOU1

For our sample of 24 customers, Table 4 summarizes the calculated optimal (i.e., "least cost") retail rate both before the PV system is installed, and after the system is installed, within each of the eight customer size categories that offer multiple rates. As before, we consider varying levels of PV penetration: 2% and 75%. The table summarizes the percentage of our 24-customer sample that would choose different retail tariffs before PV installation, with a PV installation at 2% penetration, and with a PV installation at 75% penetration.

The table shows that, at low levels of PV penetration, customer load characteristics largely determine the optimal retail rate, and the existence of the PV system does not lead to widespread rate switching from the before-PV case. At higher levels of PV penetration, however, a substantial proportion of customers are found to be better off switching to a rate with characteristics that favor PV; in other words, the customer's load profile is dominated by the existence of the PV system in optimal rate selection.

Table 4. Optimal Rate Selection Before and After PV Installation

Optimal Rate Selection: % of Customers that Choose Each Rate, n=24

			With PV Penetration	
Utility and Customer Class	**Optimal Rate**	**Before PV**	**2%**	**75%**
LADWP 30 - 100 kW	A-2, A	25%	21%	0%
	A-2, B	75%	79%	100%
PG&E <200 kW	A-1	0%	0%	0%
	A-6	21%	21%	100%
	A-10	25%	25%	0%
	A-10 TOU	29%	29%	0%
	E-19	25%	25%	0%
PG&E 200 - 500 kW	A-6	25%	25%	100%
	A-10 TOU	50%	50%	0%
	E-19	25%	25%	0%
PG&E >1,000 kW	E-19	71%	71%	100%
	E-20	29%	29%	0%
SCE 20 - 200 kW	GS-2, TOU Option A	33%	33%	100%
	GS-2, TOU Option B	38%	42%	0%
	GS-2, Non-TOU	29%	25%	0%
SCE 200 - 500 kW	TOU-GS-3 Option A	38%	42%	100%
	TOU-GS-3 Option B	63%	58%	0%
SDG&E >500 kW	A-6 TOU	38%	38%	96%
	AL-TOU	63%	63%	4%
SMUD 20 - 300 kW	GS-Demand	13%	13%	0%
	GS-TOU3	88%	88%	100%

The text below discusses rate switching results in each of the five utility service territories.

LADWP: LADWP customers with peak demand between 30 kW and 100 kW have three basic rate options: A-2, A; A-2, B; and A-2, D. Customers cannot take service on A-2, D in combination with net metering, however, and we therefore exclude this rate from our analysis (although, in the text box at the end of this section, we show the potential value it could offer to customers with PV if it were available in conjunction with net metering). Both A-2, A and A-2, B have approximately the same demand weight and cost of electricity. Two features of the A-2, B rate, however, lead all customers in our dataset to favor this rate option at high levels of PV penetration: A-2, B has TOU energy rates, and the majority of the demand charges are TOD demand-based. As described in Chapter 5, these two rate features tend to increase the value of PV.

PG&E: When rate switching is considered, we find that customers in PG&E's service territory without PV would (optimally) choose very different rate structures depending on the customer's load shape. Only the A-1 rate, a non-TOU energy-only rate, is unattractive compared to the other rate options for all 24 customers in our sample. Table 1 also shows that none of the customers in our sample would find it attractive to change rates after installing a small PV system (2% penetration). When larger PV systems are installed (75% penetration), however, *all* of the customers in our sample are found to choose PG&E's A-6 rate, a TOU energy-only rate, if it is available.[46] Clearly, at high levels of PV production relative to customer load, PG&E's A-6 rate is the most favorable. At lower levels of penetration, however, this need not be the case. Interestingly, PG&E's A-1 rate, also an energy-only rate, is less attractive than the A-6 rate at high levels of PV penetration. The primary difference between the two rates is that the A-1 rate is not a TOU rate, so does not value the coincidence of PV production and high energy costs.

SCE: SCE offers two commercial rates that are heavily weighted towards energy-based charges. SCE's GS-2, TOU Option A rate is available to customers between 20-200 kW and the TOU-GS-3 Option A rate is available to customers between 200-500 kW. Without PV or with a small PV system neither of these rates are found to be particularly more or less attractive than the other options available in SCE's service territory, with some customers finding these rates to minimize customer bills, and others not so. When the PV system increases to 75% penetration, however, these two rates are chosen by all of the customers in our sample. Again, this demonstrates the benefit of energy-dominated charges for higher levels of PV penetration.

SDG&E: In SDG&E's service territory, the AL-TOU rate is standard for all customers larger than 20 kW, though customers larger than 500 kW can choose either the AL-TOU rate or the A-6 TOU rate. These two rates are similar in many respects, and yet the A-6 TOU rate appears optimal for most – but not all – customers at higher levels of PV penetration. The A-6 TOU rate differs from the AL-TOU rate primarily in that its demand charge is based on demand during the time of SDG&E's system peak rather than a specific TOU period. Based on our analysis here, the ability of PV to reduce customer demand during SDG&E's system peak appears to be better than the ability of PV to reduce demand over the entire TOU period.

SMUD: Customers in SMUD's service territory that are between 20 kW and 300 kW in size are able to choose between the GS-Demand and GS-TOU3 rates. Both of these rates have approximately the same demand weight (it is slightly less in the median case for GS-TOU3) and the same cost of electricity (again it is slightly less for GS-TOU3). The primary difference between the two rates is that demand charges are based on the maximum annual demand under the GS-Demand rate, while a portion of the demand-charge under the GS-TOU3 rate is based on peak customer load during the summer "Super-Peak" period. The results in Table 4 show that most customers prefer the GS-TOU3 rate before PV is installed and when a small PV system is installed, and that all of the customers in our sample switch to the GS-TOU3 rate when PV penetration increases.

[46] PG&E customers greater than 1000 kW in size are limited to the E-19 and E-20 rates, and cannot choose the A-6 rate. Our analysis finds that the E-19 rate is preferable at 75% PV penetration. Since the E-19 rate is also available in smaller customer class sizes, but none of the same customers choose the E-19 rate, customers larger than 500 kW would also choose the A-6 rate if it were available.

6.3 The Impact of Demand Charges on Optimal Rate Selection

As suggested by earlier analysis, the choice of rate structure at higher levels of PV penetration is largely driven by demand charges. Figure 25 shows the interrelationship between PV penetration level and customers' preference for rates that primarily consist of volumetric energy-based charges, with either no demand charge (PG&E A-6) or relatively small demand charges (SCE GS-2, TOU Option A and TOU-GS-3 Option A) compared to other rates offered to the same customer class.

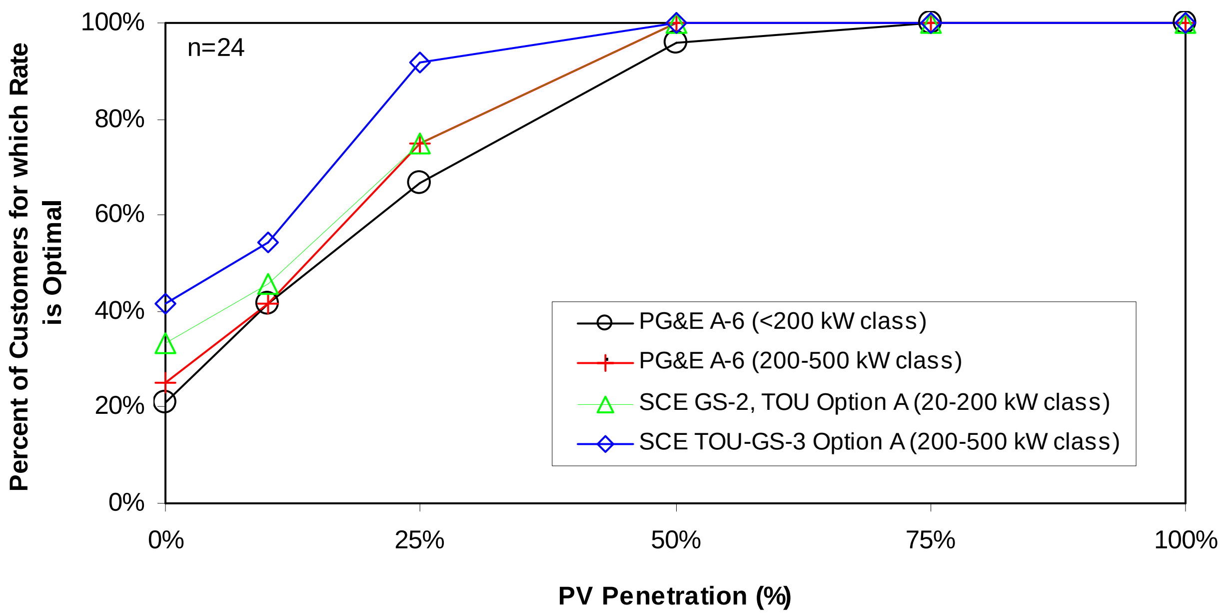


Figure 25. Customer Choice of Energy-Focused Rates at Varying Levels of PV Penetration

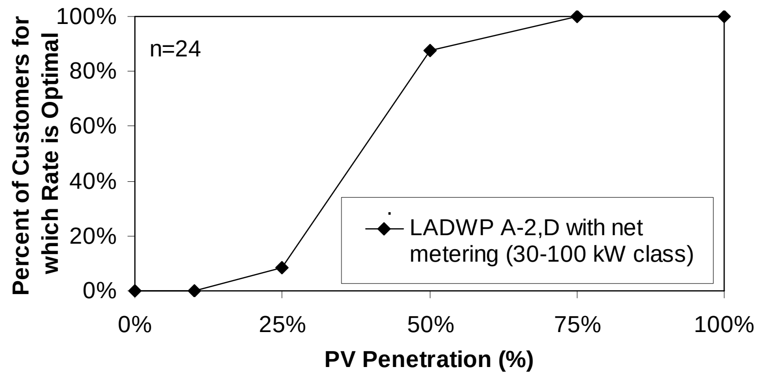
The figure demonstrates that, at low levels of PV supply relative to customer load, these rates are not universally optimal. Many customers that plan on installing a smaller PV system relative to facility load will not find switching to an energy-focused rate to be the best option. At higher levels of PV penetration, however, the energy-focused rates are almost universally most favorable. Of the 24 customers in our sample, over 90% would find the energy-focused rates to be optimal (that is, minimize electric bills) when annual PV supply exceeds 50% of the customer's load. Even at 25% PV penetration, PG&E's and SCE's energy-focused rates are optimal for over 65% of our customer sample.

The development of "PV-friendly," energy-focused rates with limited or no demand charges is therefore of particular importance to those customers interested in installing large PV systems relative to facility load. If such rates were required of *all* commercial PV systems, on the other hand, then many customers wishing to install smaller PV systems (relative to load) would be disadvantaged.

Text Box 1. LADWP's Otherwise "PV-Friendly" Rate

LADWP's A-2, D rate is not included in the primary analysis of this report because it is not offered in conjunction with net metering. Nonetheless, the rate has characteristics that would make it quite "PV-friendly" if it were available in conjunction with net metering. The rate is composed primarily of TOU-based energy charges and has a low median demand weight of only 8% (this compares to the high median demand weight of around 50% for the other two LADWP rates).

We computed customer bills for this rate across PV penetration levels, under the hypothetical assumption that customers on this rate are eligible for net metering. This figure, similar to Figure 25, shows the percentage of customers that would find the A-2, D rate optimal if net metering were offered with this rate.



As shown in the figure, at low levels of PV penetration we find that few customers would select the LADWP A-2, D rate. This is because the average cost of electricity under this rate is relatively high. At higher levels of PV penetration, however, this rate would become the most attractive rate option in LADWP's service territory for PV customers in the 30-100 kW customer class size. We therefore conclude that making net metering available to customers on LADWP's A-2, D would create significant value for LADWP customers in the 30-100 kW class that install PV systems serving a large portion of building load.

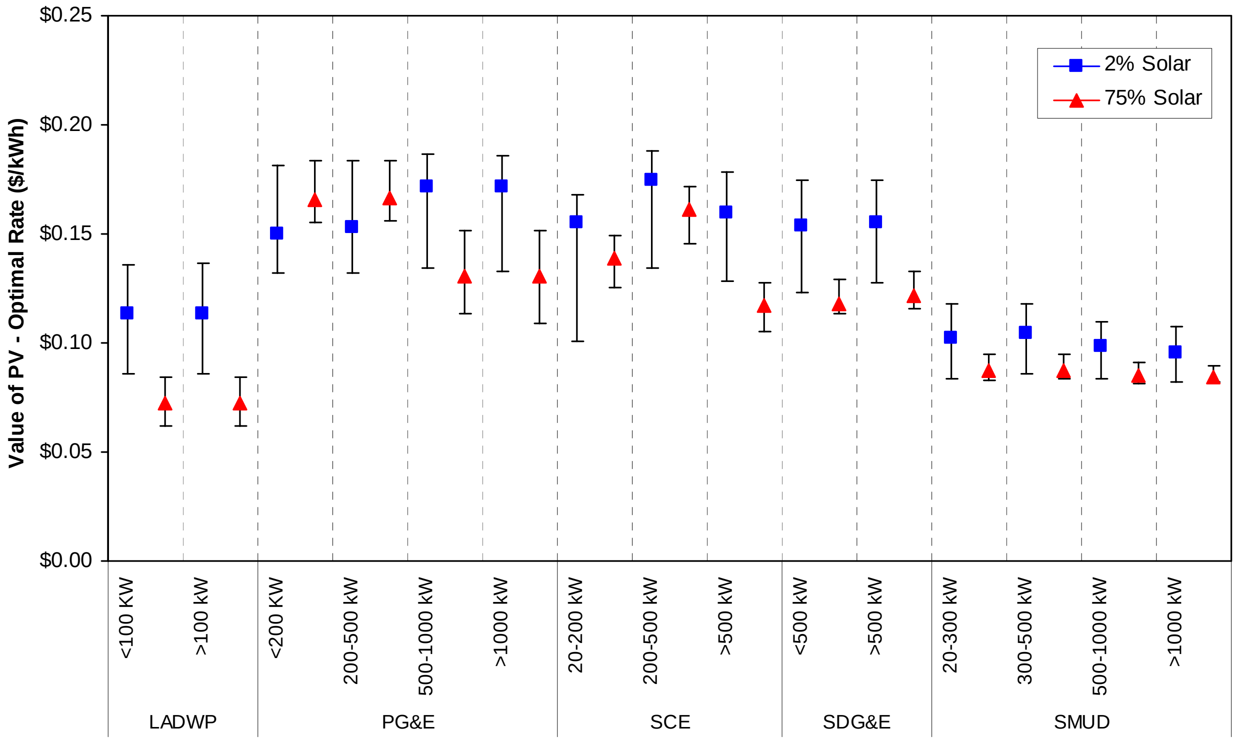
6.4 The Value of PV with Rate Switching

As noted earlier, the value of PV when rate switching is available is different than if it is assumed that a customer must stay on the same rate before and after the installation of PV. The value of PV with rate switching is calculated as the difference between the optimal electricity bill based on gross demand and the optimal electricity bill based on net demand, divided by the amount of energy produced by the PV system.[47] When a rate switch is optimal, the value of PV with rate switching is the combined impact of the installation of the PV system and the impact of the customer switching between rates.

[47] We do not attempt to disaggregate the value of a PV system calculated assuming that rate switching occurs into demand and energy components because different rates assign different weightings to demand- and energy-based charges. It is therefore not easy to distinguish reductions in the demand component due to different rate structures and due to reductions in demand caused by the PV system. As an example, under certain circumstances it may be optimal for a facility that installs PV to switch from a rate that includes demand and energy components, like PG&E's E-20 rate, to a rate based only on energy, like PG&E's A-6 rate. Though installing the PV system and making the rate switch leads to an electricity bill with a zero demand charge, the PV system cannot be credited with this reduction in demand charges.

$$VPV\ with\ Switching = \frac{Optimal\ Bill\ without\ PV - Optimal\ Bill\ with\ PV}{Annual\ PV\ Energy\ Production} \quad (\$/kWh)$$

Figure 26 presents the value of PV for each customer size class, when customers are able to choose the optimal rate available within that class, both before and after PV installation. In essence, the figure presents the most realistic picture of the value of PV in California based on current rates. Note that, as shown in Table 3, only eight of the fifteen customer size categories included in the figure have multiple rate options – the other seven customer size categories must select a single non-optional rate.



Median value with error bars for 10th to 90th percentile range

Figure 26. Value of PV for each Customer Size Class With Optimal Rates

These results show that the highest median value of PV for all customer size classes in the three IOU service territories is between $0.153/kWh and $0.171/kWh. In all but two of the IOU customer size classes, this maximum $/kWh rate-reduction value would be obtained at a 2% PV penetration level. However, for PG&E customers in the two size classes smaller than 500 kW, a greater $/kWh rate-reduction value is obtained at the higher 75% PV penetration level. For these two size classes, in which all customers switch to PG&E's "PV-friendly" A-6 rate at 75% penetration, the value of PV actually increases with penetration if rate switching is accounted for.

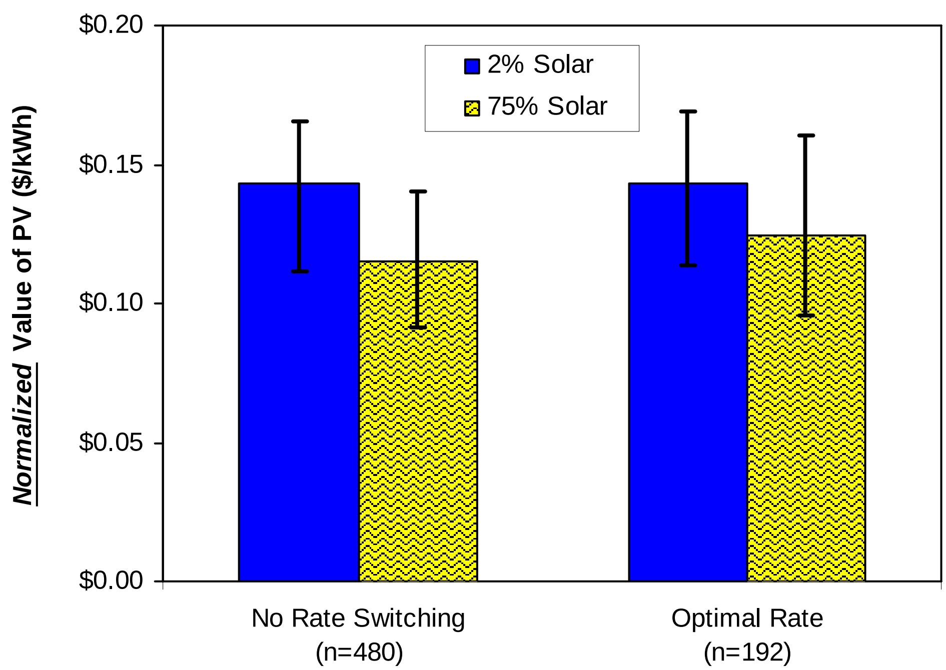
In comparison to the IOUs, the highest median value across all customer classes in LADWP and SMUD is $0.095/ kWh to $0.113/kWh. All customer size classes in these two utilities obtain the highest $/kWh value for smaller PV systems, at 2% PV penetration.

Appendix C provides additional results from this rate switching analysis, focusing specifically on the median value of PV after system installation for each optimal rate.

6.5 Comparing Rate Switching with No Rate Switching

It remains evident that variations in rate design and customer load profiles can have a substantial impact on PV economics, even under the assumption that customers are freely allowed to select among available commercial rates. The overall variation in PV value is somewhat narrower than when rate switching is not allowed (see Chapter 4), however, clustering in the range of $0.08-$0.18/kWh. This narrowing is caused by the ability of customers to optimize their electricity rate both before and after PV system installation.

Figure 27 directly compares the *normalized* value of PV for customer classes with multiple rates with those from the no-switching case presented earlier.[48] The most important difference is that the impact of PV penetration diminishes somewhat when the possibility of rate switching is acknowledged. Specifically, without rate switching, increasing PV system size from 2% to 75% of customer load reduces the median normalized value of solar electricity by a full 20%. With the assumption that customers can choose any commercial rate within each customer size class, however, the reduction in value with higher PV penetrations drops from 20% to 13%.



Median value with error bars for 10th to 90th percentile range

Figure 27. Normalized Value of PV With and Without Rate Switching

[48] There are eight customer size classes that offer multiple rates and 24 datasets, leading to 192 individual data points.

7. The Value of Net Metering for Commercial Customers

Previous chapters of this report have assumed the presence of net metering, based on the policy design currently in place in California.[49] In this chapter, we estimate the value of net metering for the customers and rates in our dataset, by comparing the value of PV in the absence of net metering to our earlier results.[50] We do not evaluate the possible impact of standby or backup rates for customer-sited PV. For this comparison, we assume that customers remain on the same rate before and after PV installation.

The *loss of value for a PV system without net metering* is defined here as the difference in the value of PV with and without net metering divided by the value of PV with net metering. Because net metering does exist in California, our non-net-metering case is simply a proxy for what might happen were net metering not available. As such, the results summarized in this chapter are illustrative, rather than definitive.

$$Loss\ of\ Value\ w/o\ Net\ Metering = \frac{VPV\ with\ Net\ Metering - VPV\ w/o\ Net\ Metering}{VPV\ with\ Net\ Metering} \times 100\ \ (\%)$$

In the absence of net metering, customers could be compensated for their PV production in several possible ways. One approach might be for the utility to purchase 100% of the PV output at a specified non-retail rate (i.e., a feed-in tariff, such as those used to compensate customer-sited PV in some European countries). Provided that the feed-in tariff is based on a flat $/kWh payment applied to all PV production, determining the loss (or gain) in value relative to net metering is quite straightforward: one can directly compare the stipulated feed-in tariff rate to the distributions in the value of PV-induced rate savings with net metering shown in Figure 6 and Figure 7.[51]

A less straightforward situation, and the one that is the subject of analysis in this chapter, is where PV production in excess of customer load during any 15-minute interval is either uncompensated (i.e., "donated" to the utility) or sold to the local electric utility at some pre-specified "sell-back" rate. In this scenario, all PV production up to the customer's load during each 15-minute interval is valued at the prevailing retail rate. The only difference between this approach and net metering comes in the treatment of excess PV production, above the customer's load, in each 15-minute interval. Though one cannot be certain about how a no-net-metering scenario would apply in California, it is certainly possible that PV would be allowed to

[49] Under California's net metering law, any net excess generation in one month can be carried forward to future months, over a one-year period. At the end of the year, if net excess generation remains, it is given for free to the local utility. Over the course of a year, in no instance is a customer's overall electrical bill allowed to be negative; the best a customer can do is to eliminate their annual electrical bill or all charges up to the fixed customer charges depending on the utility.

[50] We ignore some of the other advantages of California's net metering legislation, such as the waiver of standby charges and the requirement that utilities not charge solar customers differently then other similar customers.

[51] For example, Figure 7 indicates that with net metering on PG&E's E-19 rate, the median value of PV across the 24 customers in our dataset is approximately $0.17/kWh at 2% PV penetration. Thus, if net metering were replaced with a flat feed-in tariff rate of $0.10/kWh, half of the customers in our sample would experience a loss of value of at least $0.07/kWh or 41%.

offset retail rates up to 15-minute customer load and would be compensated at a wholesale rate for net excess production during each 15-minute interval.[52]

Using the hypothetical no-net-metering scenario described above, we begin this chapter by exploring the influence of the assumed "sell-back" rate on the estimated value of net metering. We also evaluate the relationship between the value of net metering and the level of PV penetration. Next we show that the value of net metering depends on the specific rate structure on which the customer takes service. Finally, we use the five unique load shapes used in previous chapters to illustrate how the estimated value of net metering depends on customer load shape. Again, in all of these calculations, the posited no-net-metering scenario described above is assumed to apply; results would differ if an alternative structure was assumed.

7.1 Sell-Back Rate

It is unclear at what rate the local utility might be willing to purchase net excess PV production in each 15-minute interval. To reflect this uncertainty, here we analyze the value of PV with a range of wholesale sell-back rates of \$0.05, \$0.07, and \$0.09/kWh.[53] We also analyze a pessimistic scenario in which any net excess generation during each 15-minute interval is uncompensated (i.e., a sell-back rate of \$0.00/kWh). This range reflects plausible sell back rates, but we do not suggest that sell-back rates outside of this range are not possible. For instance, a sell-back rate that accounts for avoided transmission and distribution costs in addition to avoided wholesale energy costs might be even greater than the range that we use here.

Figure 28 shows the potential economic loss for the commercial customers in our dataset under the various sell-back rates analyzed (median and $10^{th}/90^{th}$ percentiles). This loss reflects the percentage difference in PV value with and without net metering. The figure was constructed using all 24 load/production pairs crossed with the 20 retail rates. The percentile ranges therefore reflect differences in both retail rates and load/production data sets. Several key conclusions can be reached from this analysis.

First, when PV production totals less than 25% of annual customer load (PV penetration < 25%), net metering provides little incremental value to the majority of the 24 commercial customers in our dataset. The basis for this observation is that, at low PV penetration levels, little to no net excess PV generation occurs, and therefore all or almost all of the PV production is valued at the full retail rate, even without net metering. At higher PV penetrations, however, the absence of net metering can substantially degrade the economics of commercial solar installations. One implication of these findings is that, were net metering to be eliminated and replaced with the scenario assumed here, one would expect customers to gravitate towards smaller PV systems relative to their load.

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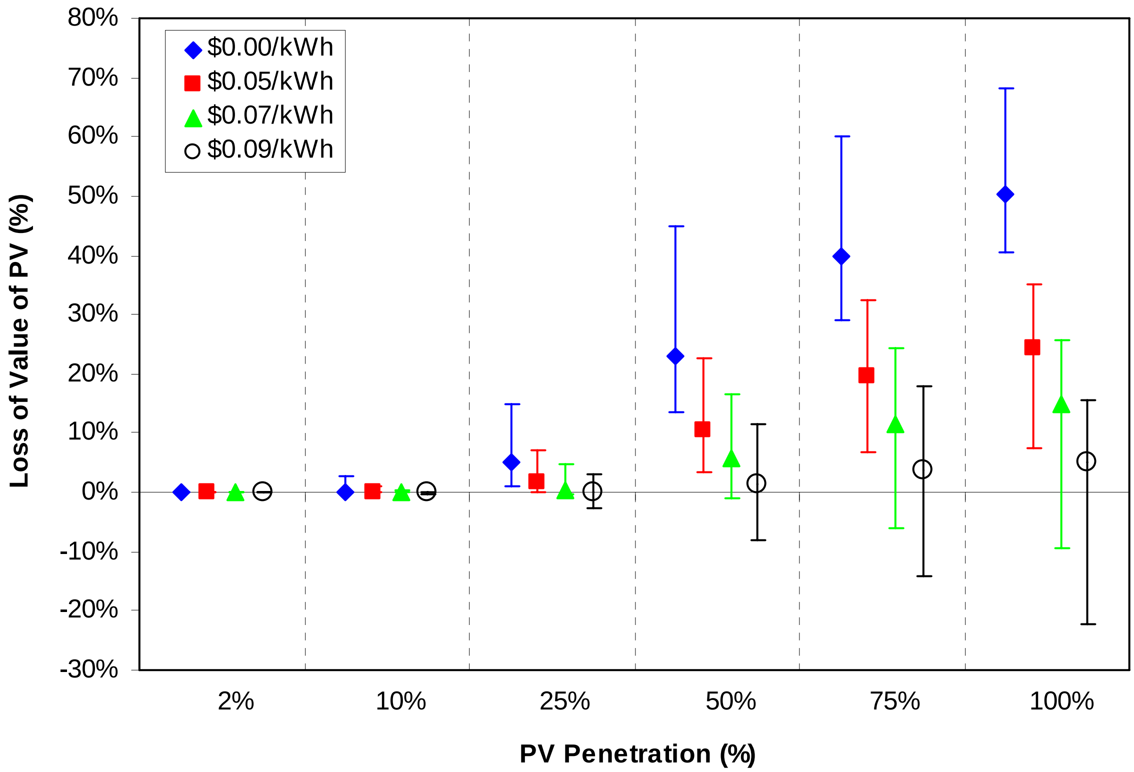
[52] Without net metering, it is assumed that the facility could not only offset its entire electricity bill but also earn income from the utility, given a high enough rate for excess energy sold to the utility.

[53] The price range for wholesale electricity transactions was generally from \$0.05/kWh to \$0.08/kWh at California's SP-15 trading hub from January 2006 to May 2007. The main exception to this range was a heat wave during the 2006 summer that briefly sent prices well over \$0.10/kWh. For more information see: http://www.eia.doe.gov/cneaf/electricity/wholesale/wholesale.html Last accessed: June 20, 2007

Second, for fairly obvious reasons, the loss of value without net metering is highly sensitive to the sell-back rate. For example, at 100% PV penetration, the median loss of value is just 5% if the utility purchases net excess generation for $0.09/kWh, the highest sell-back rate considered.[54] In comparison, the median loss of value is almost five times as large for a sell-back rate of $0.05/kWh and ten times as large if no credit is provided for net excess generation. Thus, in considering the potential loss of value from eliminating net metering, it is important to specify exactly how excess generation will be treated, particularly for systems that provide a large percentage of building load.

Finally, the wide spread between the 10th and 90th percentiles suggests that the value of net metering depends quite significantly on the particular customer and rate. The following two sections address each of these factors in more detail.



Median value with error bars for 10th to 90th percentile range

Figure 28. Value of Net Metering with Varying Sell-Back Rates and PV Penetration Levels

7.2 Rate Structure

The value of net metering depends on the details of the retail rate selected by the customer – in particular, on the structure and size of the energy charges. To illustrate this dependence, Figure 29 shows the loss of value absent net metering under the assumption that net excess generation from PV in each 15-minute interval is sold to the utility at $0.07/kWh, for three distinct retail

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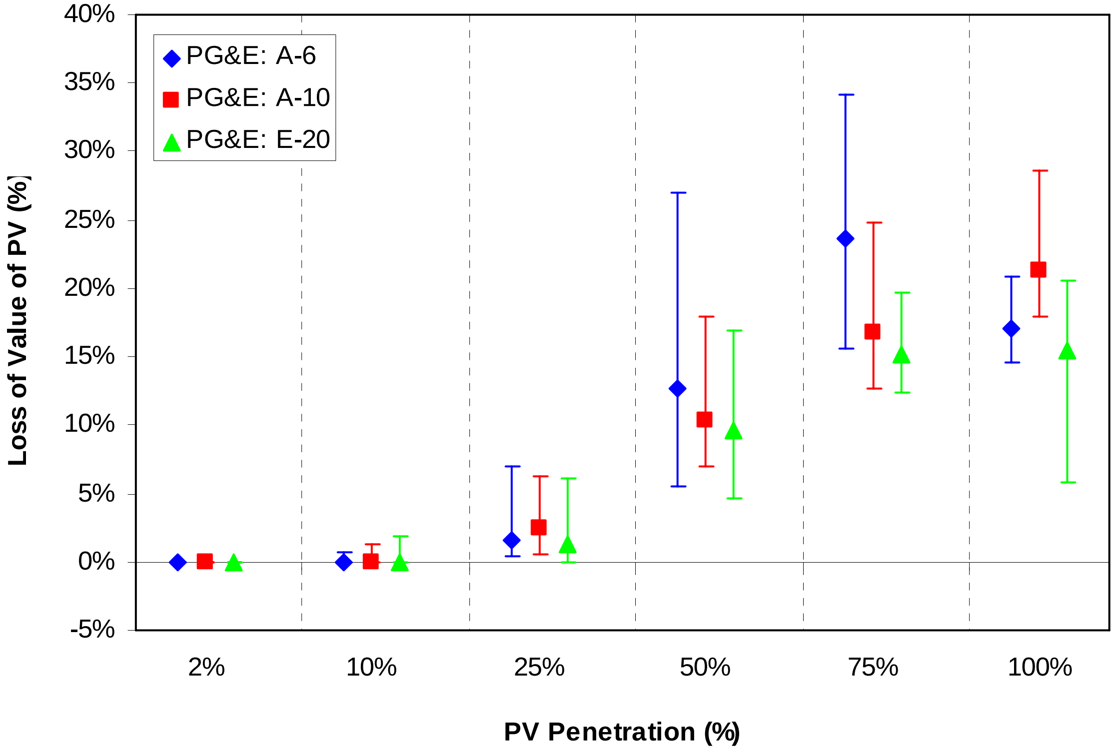
[54] In some cases, selling net excess production at $0.09/kWh appears more attractive than net metering, as indicated by those points in the figure that extend into negative territory. This would occur in the (rather unlikely) scenario where the utility offers a sell-back rate that exceeds its retail energy rate.

rates: PG&E's energy-only TOU rate (A-6), a non-TOU energy and monthly demand charge rate (A-10), and a TOD-based demand and TOU-based energy rate (E-20). Again, these results assume that, without net metering, PV production will be treated as described earlier in this chapter.

Interestingly, the potential economic loss from eliminating net metering is greatest under what might be considered the most "PV-friendly" retail rate, PG&E's A-6, at least up to PV penetration levels of around 75%.[55] This is because net metering only impacts energy charges, and has no impact on demand charges. As such, customers taking service under rates with small demand charges (or, in the extreme, energy-only rates such as A-6) have more to lose from the potential elimination of net metering than do customers on retail rates with larger demand charges.



Median value with error bars for 10th to 90th percentile range

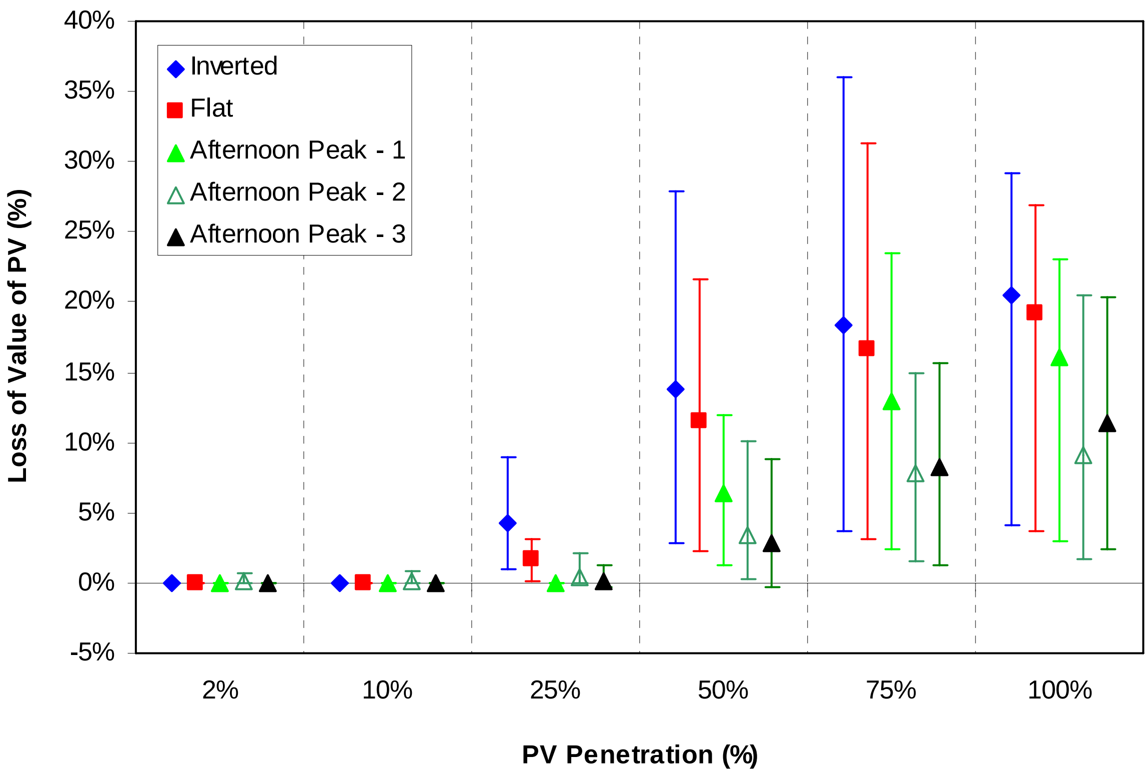
Figure 29. Value of Net Metering by Rate Structure ($0.07/kWh sell back rate)

55 At very high levels of penetration, the loss associated with the A-6 rate begins to decline. This is due to the fact that, with net metering, the customer can at best zero out their bill. At PV penetration rates greater than 75%, the customer begins to zero out their bill when the output is net metered, because each kWh offset by the PV system is valued more highly than the average cost of electricity to the facility. As such, increasing the size of the PV system beyond 75% has marginal to no benefits to a customer on net metering – and thus the percentage reduction in value from eliminating net metering declines.

7.3 Customer Load Shape

Figure 30 shows how the economic value of net metering may also be influenced by customer load shape, using the five representative customer load shapes introduced earlier and again assuming a sell-back rate of $0.07/kWh. To construct the figure, we mixed-and-matched each set of load data with all of the 24 PV production profiles, and determined the loss of value without net metering for the paired datasets across all 20 retail rates. Thus, the percentile bands reflect differences in rates and PV production profiles.

Customers with flat or inverted load shapes clearly have more to lose from the elimination of net metering than do those customers with more typical afternoon peaks, assuming that the treatment of PV production in the absence of net metering is similar to what was posited earlier. The intuition for this finding is straightforward: customers with inverted or flat load shapes have proportionately less load to offset with PV production on summer afternoons, when PV production is typically at its highest, and therefore face a greater amount of net excess PV production. Customers with load shapes that match PV production profiles depend less on net metering, and thus are able to host proportionately larger PV systems without experiencing significant erosion in value if net metering is eliminated.



Median value with error bars for 10th to 90th percentile range

Figure 30. Value of Net Metering by Load Shape ($0.07/kWh sell back rate)

8. Conclusions

The solar power market is booming. Though this growth has been spurred by government policy, the ultimate goal of these policies is often to create a self-sustaining PV industry that is able to succeed with a minimum of government intervention. To do so, solar will likely need to be competitive compared to retail electricity rates.

The importance of retail rate design for the economics of PV is sometimes overlooked, or simplified into a single-minded call for net metering. But, as we have shown in this report, the importance of rate design goes well beyond the availability of net metering. Instead, the specifics of the rate structure, combined with the characteristics of the customer's underlying load and the size of the PV system, can have a substantial impact on the economics of customer-sited commercial PV systems. Though our detailed findings are specific to California, many of them have broader implications for other states as well.

Though regulators must consider a number of sometimes-conflicting objectives when designing and approving retail rates, key conclusions for policymakers that emerge from our analysis include the following:

- **Rate design is fundamental to the economics of commercial PV.** The rate-reduction value of PV to our diverse sample of commercial customers in California, considering all available commercial tariffs, ranges from \$0.05/kWh to \$0.24/kWh, reflecting differences in rate structures, the revenue requirements of the various utilities, the size of the PV system relative to building load, and customer load shapes. When we normalize for differences in the *magnitude* of the rates, we find that differences in rate *structure*, alone, can alter the value of PV by 25% to 75% for the average customer in our sample, depending on the size of the PV system relative to building load. For some customers, the impacts are even larger. The most attractive retail rates in California are found to offer typical PV customers a rate reduction value of over \$0.17/kWh.

- **TOU-based energy-focused rates can provide substantial value to many PV customers.** Retail rates that wrap all or most utility cost recovery needs into TOU-based volumetric energy rates, and which exclude or limit demand-based (and fixed customer) charges, provide the most value to PV systems across a wide variety of circumstances. Almost universally, at higher levels of PV penetration, these energy-focused rates are found to be preferable to PV customers. Under a same-rate analysis, the TOU-based energy-focused rates offered by PG&E (A-6) and SCE (GS-2, TOU Option A; TOU-GS-3 Option A), for example, are found to provide a median PV value in the range of \$0.16-\$0.18/kWh at relatively low PV penetration levels, well above the value offered by most other rates. Additionally, unlike rates that contain significant demand charges, under energy-focused rates the value of PV does not drop substantially as PV penetration increases. Some utilities in California (SMUD and SDG&E) do not currently offer rates with low demand-based charges, and some of the other utilities only offer these energy-focused rates to customers below a certain size threshold (< 500 kW for SCE and PG&E). Expanding the availability of rates with low demand charges will increase the value of many commercial PV systems, especially those systems that are large relative to the building load.

- **Offering customers a variety of rate options would be of value to PV.** Despite the advantages of TOU-based, energy-focused rates for many commercial PV systems, *requiring* the use of these types of tariffs would economically disadvantage some PV installations.[56] In particular, for PV systems that serve less than 25-50% of annual customer load, the characteristics of the customer's underlying load profile often determine the most favorable rate structure, and energy-focused rate structures are not be ideal for many customer load shapes. Clearly, the most favorable retail rates for PV depend not only on the underlying rate structure, but also on the characteristics of the customer, including the size of the PV system relative to facility load and the temporal characteristics of customer load. Regulators that wish to establish rates that are beneficial to a range of PV applications should therefore consider allowing customers to choose from among a number of different rate structures.

- **Eliminating net metering can significantly degrade the economics of PV systems that serve a large percentage of building load.** Under the assumptions provided in Chapter 7, we find that an elimination of net metering could, in some circumstances, result in more than a 25% loss in the rate-reduction value of commercial PV. This represents a sizable loss, and suggests that net metering offers important support for solar in the commercial market. Losses of this magnitude are most prevalent among customers with inverted (or flat) load profiles, customers whose PV systems supply more than 50% of annual facility demand, and when exported net-excess generation receives a relatively low payment rate from the local utility. Those customers taking service under "PV-friendly" energy-focused rates also have more to lose from the potential elimination of net metering than do customers on alternative retail rates that involve larger demand charges. Among our dataset of 24 commercial customers, however, as long as annual solar output is less than roughly 25% of customer load and excess PV production can be sold to the local utility at a rate above $0.05/kWh, an elimination of net metering is found to rarely result in a loss of consumer value that exceeds 5%, assuming that the no-net-metering case is similar to that posited in Chapter 7. This is because, at this level of PV penetration, there is little export of solar production to the grid. Overall, though net metering is found to be valuable, its loss to commercial customers might lead, most tangibly, to PV systems that are sized to serve a smaller proportion of annual customer load.[57]

[56] As one example, California's SB 1 mandates that the CPUC require time-variant pricing for solar customers, and that "The commission shall develop a time-variant tariff that creates the maximum incentive for ratepayers to install solar energy systems so that the system's peak electricity production coincides with California's peak electricity demands and that assures that ratepayers receive due value for their contribution to the purchase of solar energy systems and customers with solar energy systems continue to have an incentive to use electricity efficiently." The results presented in this report show that an energy-focused TOU rate structure, while favorable to PV, will not be attractive to all solar customers. Therefore, a requirement that all PV customers take service under such a tariff would be less valuable for the solar market than would an optional tariff of this nature.

[57] Net metering may be more valuable for residential customers, given the often-poor coincidence between residential electricity demands and PV production. Also note that, for commercial customers, California's net metering legislation provides additional benefits not analyzed in this report, namely a waiver of standby charges and a requirement that utilities not charge solar customers differently than other similar customers.

More detailed conclusions on the rate-reduction value of commercial PV include:

- **Commercial PV systems can sometimes greatly reduce demand charges**. Demand charges can sometimes represent over 50% of the cost of electricity for commercial customers in California. A common misconception is that PV systems can do little to reduce these demand charges. In fact, though energy-focused retail rates often offer the greatest rate reduction value for PV, we find that demand charges can sometimes be substantially reduced by the installation of PV systems. In many instances, at low PV penetration levels, demand charge savings are found to represent 10-50% of total rate savings derived from PV installations. Demand charge reductions can be especially considerable for customers whose PV systems represent a small proportion of annual load, and for customers whose load profiles include strong afternoon peaks that are coincident with typical solar production. In these instances, the existence of demand charges need not substantially degrade the value of PV, and analyses of the value of commercial PV installations should not ignore the possibility of demand charge savings. Unfortunately, because smaller commercial customers often lack detailed facility-load-shape data, and because facility load shapes can change from one year to the next, it may be difficult to accurately estimate demand-charge savings.

- **The value of demand charge reductions declines at higher levels of PV penetration.** Though demand charge savings are possible, those savings are far more modest, and sometimes close to zero (on a $/kWh basis), when PV production as a proportion of customer load is high. At higher levels of PV penetration, the value of that PV production is directly and dramatically impacted by the proportion of a customer's bill that derives from demand charges. Our analysis, for example, shows that the average $/kWh value of PV can be cut in half when one moves from an energy-focused rate to the most demand-weighted rate, at 75% PV penetration. Said differently, we find that the effective capability of PV to offset peak customer demand averages from 35-65% of PV capacity at 2% penetration, but drops to 5-20% at 75% penetration.[58] The result of this effect is that, for rates with significant demand charges, the drop in demand charge savings dramatically reduces the overall rate-reduction value of PV as system size increases relative to customer load. In fact, in our complete sample, the median value of PV plummets from $0.143/kWh to $0.115/kWh when PV penetration increases from 2% to 75%, a drop of 20%. When we account for the ability of customers to choose among multiple optional rates, the loss in value with PV penetration is smaller, but still significant. Commercial retail rates with demand charges therefore encourage smaller PV systems relative to facility demand.

- **The ability of PV to offset demand charges is highly customer-specific.** Energy-focused retail rates provide similar value to all PV customers, regardless of the temporal match between PV production and customer load. In contrast, the ability of PV systems, especially at low levels of penetration, to offset demand charges depends critically on the load characteristics of the customer. This is because the value of demand reduction depends, in large part, on the correlation of the time-dependent performance of the PV system to the time-dependent load of the building. Customers with loads that peak in the afternoon are

[58] These are average values, and many customers will witness effective capacity that is well outside this range.

often able to receive significant demand charge savings across a wide variety of circumstances, at least at lower levels of PV output relative to building load. In contrast, facilities with flat or inverted load profiles will often not earn much demand charge reduction value, regardless of PV system size. Most obviously, customers with peak demands during the evening hours will often gain little demand charge reduction from installing PV. As a result, the ability to offset demand charges is *far more* customer specific than is the ability to reduce energy-based charges, and a customer-specific analysis should therefore be conducted by prospective PV purchasers. Unfortunately, because commercial customers often lack detailed load-shape data, it may be difficult to accurately estimate demand-charge savings.

- **The type of demand charge can impact the ability of PV to offer savings.** Demand charges may be designed in many ways. In general, we find that TOD-based demand charges are more favorable to PV under a broad range of customer load shapes than are those based on monthly or annual peak customer demand. Though customers with afternoon peak loads will benefit the most from the effect of PV in reducing demand-based charges, customers with flat and inverted load shapes may also achieve demand savings under a TOD-based demand-charge structure. This is because PV systems will most likely be generating power during some of the highest-valued TOD periods (summer afternoons). For those customers with traditional afternoon peaking loads, on the other hand, the type of demand charge does not (in general) seem to have as much of an impact on the value of PV.

- **The type and design of energy-charges also has an important impact on PV value.** Unlike for demand charges, the level of PV penetration and the load profile of the customer do not, in general, impact the ability of commercial PV systems to reduce energy-based charges. Just as the design of demand-based charges affects the rate-reduction value of PV, however, so to does the design of energy-based charges. TOU-based energy charges with relatively little spread between peak and off-peak prices, for example, are found to offer approximately 5-10% greater energy charge savings for commercial PV customers than do rates with seasonal or flat energy charges. TOU-based energy charges with a larger price spread between peak and off-peak prices can sometimes offer 20% greater energy charge savings than seasonal or flat energy charges.

- **Differences in temporal PV production profiles have a relatively modest impact on PV value.** The specific orientation of a PV system could conceivably influence the magnitude of bill savings due to its effect on both the overall amount of energy produced and the temporal pattern of that energy production. By examining bill savings in $/kWh terms, we focus only on the latter effect. Interestingly, we find that the specific temporal profile of PV production, at least among the 24 systems in our sample, has a relatively modest impact on the *per kWh* value of both energy charge and demand charge savings, at less than $0.01/kWh in most instances. This suggests that, when one conducts customer-specific analysis, it may not be essential to use a highly-tuned estimate of the site-specific PV production profile for the purpose of deriving the $/kWh rate reduction value.

Ultimately, we conclude that choices made by utility regulators in establishing or revising retail rates can have a profound impact on the future viability of customer-sited solar markets. We hope that the analysis presented in this paper will serve as a useful step in illuminating some of the aspects of rate design that are of particular salience, and will also assist PV retailers and customers better asses the value proposition of commercial PV systems.

Several extensions of this work are recommended. First, it would be useful to assess whether simulated hourly PV production data (which is readily available) can replace real PV production data (which is not readily available) and still accurately estimate demand charge savings. Second, one might broaden the analysis to include other states, where a greater range of rate designs exist, allowing one to evaluate the impact of standby/backup rates and tiered rate structures on the value of commercial PV, as well as the impact of alternative net metering designs. Third, a more thorough analysis of residential rate structures, and the impact of those rate structures on a sample of real projects may be valuable. Finally, more analysis is needed on the specific benefits bestowed by PV to the grid so that rate design can be better informed by the nature and magnitude of these impacts.

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Appendix A. Further Description of Rates Used in Analysis

The commercial rates used in this study were selected from the five largest utilities in California: PG&E, SCE, SDG&E, LADWP, and SMUD. Rate information was obtained from utility tariff books valid as of January 2007.

The rates selected for this study were for commercial and industrial facilities with a maximum demand greater than 100kW, and with power delivered at voltages below the transmission voltage. The specific rates included in our study are listed in Table 5.

Table 5. List of Rates Included in Analysis

Rates Evaluated in Analysis	
Utility	Rate Name
LADWP	A-2, A; A-2, B/ A-3, C
PG&E	A-1; A-6; A-10; A-10 TOU; E-19; E-20
SCE	GS-2, Non-TOU; GS-2, TOU Option A/B; TOU-GS-3 Option A/B; TOU-8
SDG&E	AL-TOU; A-6 TOU
SMUD	GS-Demand; GS-TOU3; GS-TOU2; GS-TOU1

These rates can be loosely categorized by the type of demand charges used. We classify the rates as Energy Only, TOD Demand Charges, and Non-TOD Demand Charges. The category of TOD Demand charges includes any rate that has a TOD demand charge component. It should be noted, however, that nearly all of the rates with TOD demand charges include a non-TOD demand component as well. Note that, below, we do not present data on the fixed, recurring customer charges included in some of the retail rates offered by California's electric utilities. This is because these charges are typically small, in absolute terms, as shown in Chapter 5.

Energy Only, No Demand Charges

PG&E offers two rates, A-1 and A-6, that do not include demand charges. The A-6 rate is a TOU energy rate based wholly on the quantity of energy used by the facility (at specific times) and a fixed monthly customer charge. The rate is characterized by very high energy charges during the summer peak period and low energy charges in the off-peak periods. The energy component of the A-1 rate changes only between the winter and summer season and does not depend on the time of day when energy is consumed.

Table 6. Rates Based Only on Energy Charges

Energy Only			
Utility	Rate Name	Class Size	Energy Rates
LADWP	None	-	-
PG&E	A-1	Demand < 200 kW	Seasonal
PG&E	A-6	Demand < 500 kW	TOU
SCE	None	-	-
SDG&E	None	-	-
SMUD	None	-	-

TOD Demand Charges

Time-of-day (TOD) demand charges are based on maximum facility demand during specific time of use periods each month (this contrasts with monthly demand charges, which are based on the maximum demand that occurs each month irrespective of what time of day it occurs). Each utility includes a rate based on TOU energy charges and TOD demand charges (see Table 7). Note that in each case, in addition to the TOD demand charge, a "facilities charge" is also applied. The design of these facilities charges vary, and are based on both maximum monthly and maximum yearly demand. In effect, these represent additional demand-based charges.

At one end of the spectrum, LADWP applies TOD demand charges to High, Low, and Base periods in both the winter and summer seasons. On the other end, SMUD applies TOD demand charges only in the summer Super-Peak period; TOD demand charges in the remaining periods are zero. The remaining rates are generally somewhere in between demand charges based on each TOD period (the LADWP approach) and demand charges that only apply in one TOD period (the SMUD approach).

SDG&E's A-6 TOU rate is different from the other TOD rates in that the TOD demand charge is based on net facility demand at the time of the month that SDG&E's system reaches its maximum demand, rather than on a fixed period defined up-front. Customers are given a communication device that indicates demand on the overall SDG&E system, allowing customers to change their consumption behavior at the time that the system is peaking each month.

PG&E's E-19 and E-20 rates include an "average rate-limiter" during summer months that sets a limit on the average cost the customer will pay for energy and demand charges. If, according to the customer's usage pattern, a monthly summer bill would be higher than the rate limiter, then the customer's bill will be reduced so that the average cost does not exceed the rate limit of \$0.20614/kWh for E-20 and \$0.20990/kWh for E-19. We included the rate limiter in the analysis provided in this report, and it was found to affect customer bills in a few cases both with and without a PV system installed.

Table 7. Rates Based on Time of Day Demand Charges

Time of Day (TOD) Demand Charges

Utility	Rate Name	Class Size	Energy Rates	Facility Charge	Demand Charge
LADWP	A-2, B/ A-3, C	A-2, B is optional if demand <100 kW and required if 100 kW < demand < 500 kW. A-3, C is required if demand > 500 kW	TOU	Small (<$3/kW-mo), based on maximum annual demand	Based on maximum demand in High, Low, and Base periods each month
PG&E	E-20	Optional if demand > 1000 kW	TOU	Medium (<$9/kW-mo), based on maximum demand each month	Based on maximum demand in Peak and Part-Peak periods each month
PG&E	E-19	Required if 500 kW < demand < 1000 kW, optional for all other sizes	TOU	Same as above	Same as above
SCE	TOU-8	Required if demand > 500 kW	TOU	Medium (<$9/kW-mo), based on maximum demand each month	Based on maximum demand in Summer On-Peak and Mid-Peak periods
SCE	TOU-GS-3 Option B	Optional if 200 kW < demand < 500 kW	TOU	Same as above	Same as above
SDG&E	A-6 TOU	Optional if demand > 500 kW	TOU	High (>$11/kW-mo), based on greater of maximum demand each month or half of maximum annual demand	Based on maximum demand at the time of the SDG&E system peak
SDG&E	AL-TOU	Standard rate if demand > 20 kW	TOU	Same as above	Based on maximum demand during the On-Peak period
SMUD	GS-TOU2	Required if 500 kW < demand < 1000 kW	TOU	Small (<$3/kW-mo), based on maximum annual demand	Based on maximum demand during the Super Peak period for each summer month
SMUD	GS-TOU3	Optional if demand < 300 kW and required if 300 kW < demand < 500 kW	TOU	Same as above	Same as above

Non-TOD Demand Charges

A large number of the rates included in our analysis do not include a TOD-demand component, as shown in Table 8. Instead, demand charges are based on maximum customer demand during the month or maximum customer demand during the past twelve months. The magnitude of the monthly demand charges in some cases varies between summer and winter seasons; in general, summer demand charges are significantly higher than winter demand charges. In other cases, the magnitude of the demand charge does not change with season. Facilities charges also sometimes apply based on maximum monthly or maximum yearly demand; in effect, these represent additional demand-based charges.

Four of the utility rates in our sample include demand charges that are based only on the maximum demand of the facility over the previous twelve months. LADWP's A-2, D rate is primarily an energy-based rate, but it includes a small facilities charge in addition to the TOU based energy charges. SMUD's GS-TOU1 rate similarly places more weight on the energy based components.

Energy-based charges vary among these rates, and include TOU rates, energy rates that change with the season, and energy rates that are fixed.

Table 8. Rates Based on Monthly or Annual Demand Charges

Non - TOD Demand Charges

Utility	Rate Name	Class Size	Energy Rates	Facility Charge	Demand Charge
LADWP	A-2, A	Optional if 30 kW < demand < 100 kW	Flat	Small (<$3/kW-mo), based on maximum annual demand	Based on maximum demand each month
PG&E	A-10	Optional if demand < 200 kW	Seasonal	-	Based on maximum demand each month
PG&E	A-10 TOU	Optional if demand < 500kW	TOU	-	Based on maximum demand each month
SCE	GS-2, Non-TOU	Optional if 20 kW < demand < 200 kW	Seasonal	Medium (<$9/kW-mo), based on maximum demand each month	Based on maximum demand for each summer month
SCE	GS-2, TOU Option A	Optional if 20 kW < demand < 200 kW	TOU	Same as above	-
SCE	GS-2, TOU Option B	Optional if 20 kW < demand < 200 kW	TOU	Same as above	Based on maximum demand for each summer month
SCE	TOU-GS-3 Option A	Optional if 200 kW < demand < 500 kW	TOU	Same as above	-
SDG&E	None	-	-	-	-
SMUD	GS-Demand	Optional if 20 kW < demand < 300 kW	Seasonal	Medium (<$9/kW-mo), based on maximum annual demand	-
SMUD	GS-TOU1	Required if demand > 1000 kW	TOU	Small (<$3/kW-mo), based on maximum annual demand	-

Derived Characteristics of Each Rate

The multiple linear regression analysis presented at the end of Chapter 5 is based on four characteristics of the rates as applied to our 24-customer sample: the median cost of electricity, the median demand weight, the ratio of the price of energy during the summer peak TOU period to the winter off-peak period, and the median portion of demand charges due to summer peak TOD demand charges. These values are shown in tabular form in Table 9.

Table 9. Derived Characteristics of Each Rate

Characteristics of Rates Derived from the Sample of Datasets

	Rate	Median Cost of Electricity ($/kWh)	Median Demand Weight (%)	TOU Price Spread	Median Portion of Demand Charges from Summer Peak TOD Demand (%)
LADWP	A-2, A	$0.1078	50.4%	1.000	0.0%
	A-2, B/ A-3, C	$0.1078	49.7%	1.779	23.3%
PG&E	A-1	$0.1616	0.0%	1.379	N/A
	A-6	$0.1443	0.0%	3.158	N/A
	A-10	$0.1418	18.0%	1.320	0.0%
	A-10 TOU	$0.1404	18.2%	1.668	0.0%
	E-19	$0.1501	37.6%	1.842	46.5%
	E-20	$0.1518	37.3%	1.874	45.5%
SCE	GS-2, TOU Option A	$0.1445	16.2%	3.590	0.0%
	GS-2, TOU Option B	$0.1412	36.2%	1.617	0.0%
	GS-2, Non-TOU	$0.1424	36.2%	1.100	0.0%
	TOU-GS-3 Option A	$0.1584	15.5%	4.467	0.0%
	TOU-GS-3 Option B	$0.1561	35.4%	1.657	39.8%
	TOU-8	$0.1509	36.3%	1.655	36.8%
SDG&E	A-6 TOU	$0.1479	29.7%	2.158	13.1%
	AL-TOU	$0.1474	30.9%	2.158	14.3%
SMUD	GS-Demand	$0.1040	23.0%	1.073	0.0%
	GS-TOU3	$0.1029	20.0%	2.563	37.0%
	GS-TOU2	$0.0971	17.2%	2.519	41.8%
	GS-TOU1	$0.0953	14.5%	2.037	0.0%

Appendix B. Data Sources and Characteristics

Table 10 provides a somewhat more detailed summary of the 24 customer load and PV production datasets used for analysis throughout this report.

Table 10. Customer Load and PV Production Data Characteristics

Data Characteristics					
Site	**Load Factor (%)**	**Energy from Solar (%)**	**Region**	**Duration of Data**	**Data Availability (%)**
1	67.6%	1.3%	5 - Southern, Coastal	1/1/2005 - 12/31/2005	98.4%
2	64.4%	8.3%	1 - Northern, Coastal	1/1/2005 - 12/31/2005	99.7%
3	64.2%	2.0%	2 - Northern, Valley	1/1/2005 - 12/31/2005	96.9%
4	55.7%	2.9%	5 - Southern, Coastal	4/1/2005 - 3/31/2006	99.9%
5	49.0%	40.9%	1 - Northern, Coastal	1/1/2005 - 12/31/2005	98.8%
6	47.3%	26.8%	4 - Central, Valley	6/20/2005 - 6/19/2006	99.4%
7	45.9%	26.2%	2 - Northern, Valley	6/20/2005 - 6/19/2006	99.9%
8	44.4%	20.1%	2 - Northern, Valley	6/20/2005 - 6/19/2006	97.6%
9	38.7%	53.6%	2 - Northern, Valley	5/10/2005 - 5/9/2006	99.4%
10	37.6%	72.8%	2 - Northern, Valley	2/1/2005 - 1/31/2006	99.7%
11	33.3%	35.4%	6 - Southern, Valley	6/20/2005 - 6/19/2006	99.9%
12	32.6%	74.7%	2 - Northern, Valley	1/1/2004 - 12/31/2004	99.7%
13	29.5%	89.9%	2 - Northern, Valley	1/1/2004 - 12/31/2004	99.7%
14	29.4%	68.9%	2 - Northern, Valley	1/1/2005 - 12/31/2005	100.0%
15	28.5%	82.0%	3 - Central, Coastal	6/20/2005 - 6/19/2006	99.8%
16	26.6%	91.4%	2 - Northern, Valley	5/10/2005 - 5/9/2006	99.2%
17	26.3%	32.8%	5 - Southern, Coastal	7/12/2005 - 7/12/2006	98.6%
18	25.9%	40.1%	2 - Northern, Valley	6/20/2005 - 6/19/2006	99.9%
19	25.5%	93.4%	1 - Northern, Coastal	1/1/2005 - 12/31/2005	100.0%
20	22.6%	141.1%	2 - Northern, Valley	6/20/2005 - 6/19/2006	99.4%
21	21.4%	7.2%	1 - Northern, Coastal	6/20/2005 - 6/19/2006	99.4%
22	20.6%	83.8%	2 - Northern, Valley	5/10/2005 - 5/9/2006	99.6%
23	20.3%	89.0%	1 - Northern, Coastal	6/1/2005-5/31/2006	100.0%
24	17.2%	69.5%	1 - Northern, Coastal	1/1/2005 - 12/31/2005	99.8%

Appendix C. Supplemental Analysis Results

Value of PV with Net Metering, No Rate Switching

Chapter 4 presents the value of PV on each rate assuming that customers must remain on the same rate before and after the installation of PV and that net metering was available. Table 11 presents the same results in tabular form. The column labeled “Unscaled Solar” refers to the value of PV using the unscaled, original PV and load dataset.

Table 11. Value of PV on Each Rate at Various Levels of PV Penetration

Value of PV - Same Rate ($/kWh); n=24

		2% Solar		**75% Solar**		**Unscaled Solar**	
	Rate	Median	(10, 90 percentile)	Median	(10, 90 percentile)	Median	(10, 90 percentile)
LADWP	A-2, A	$ 0.111	(0.054, 0.134)	$ 0.061	(0.052, 0.075)	$ 0.066	(0.053, 0.097)
	A-2, B/ A-3, C	$ 0.113	(0.086, 0.136)	$ 0.072	(0.062, 0.085)	$ 0.078	(0.069, 0.104)
PG&E	A-1	$ 0.167	(0.165, 0.17)	$ 0.167	(0.165, 0.17)	$ 0.167	(0.164, 0.17)
	A-6	$ 0.181	(0.175, 0.186)	$ 0.178	(0.173, 0.185)	$ 0.177	(0.162, 0.186)
	A-10	$ 0.144	(0.12, 0.153)	$ 0.120	(0.117, 0.127)	$ 0.123	(0.117, 0.136)
	A-10 TOU	$ 0.149	(0.123, 0.158)	$ 0.125	(0.122, 0.132)	$ 0.128	(0.122, 0.14)
	E-19	$ 0.171	(0.135, 0.187)	$ 0.130	(0.113, 0.152)	$ 0.136	(0.119, 0.155)
	E-20	$ 0.165	(0.13, 0.183)	$ 0.125	(0.107, 0.147)	$ 0.131	(0.113, 0.15)
SCE	GS-2, TOU Option A	$ 0.161	(0.142, 0.173)	$ 0.143	(0.138, 0.151)	$ 0.145	(0.139, 0.156)
	GS-2, TOU Option B	$ 0.152	(0.097, 0.169)	$ 0.103	(0.095, 0.12)	$ 0.110	(0.096, 0.138)
	GS-2, Non-TOU	$ 0.146	(0.091, 0.163)	$ 0.097	(0.089, 0.114)	$ 0.104	(0.089, 0.132)
	TOU-GS-3 Option A	$ 0.181	(0.162, 0.195)	$ 0.162	(0.155, 0.172)	$ 0.164	(0.157, 0.176)
	TOU-GS-3 Option B	$ 0.167	(0.135, 0.185)	$ 0.124	(0.112, 0.135)	$ 0.128	(0.116, 0.153)
	TOU-8	$ 0.160	(0.128, 0.179)	$ 0.117	(0.105, 0.128)	$ 0.121	(0.11, 0.146)
SDG&E	A-6 TOU	$ 0.159	(0.129, 0.179)	$ 0.125	(0.116, 0.136)	$ 0.131	(0.121, 0.151)
	AL-TOU	$ 0.153	(0.123, 0.175)	$ 0.118	(0.113, 0.129)	$ 0.123	(0.116, 0.143)
SMUD	GS-Demand	$ 0.102	(0.076, 0.122)	$ 0.080	(0.076, 0.093)	$ 0.082	(0.076, 0.106)
	GS-TOU3	$ 0.104	(0.086, 0.118)	$ 0.087	(0.083, 0.095)	$ 0.090	(0.083, 0.106)
	GS-TOU2	$ 0.098	(0.084, 0.11)	$ 0.085	(0.081, 0.091)	$ 0.087	(0.081, 0.1)
	GS-TOU1	$ 0.095	(0.082, 0.107)	$ 0.084	(0.082, 0.09)	$ 0.085	(0.081, 0.098)

Value of PV with Net Metering, with Rate Switching

Chapter 6 provided information on the optimal rate switching strategy among our sample of customers, at various PV penetration levels. The tables that follow provide additional results from this analysis, focusing specifically on the median value of PV after system installation for each optimal rate, at various levels of PV penetration.

Table 12. Value of PV After Rate Switching: LADWP

Value of Rate Switching (median, $/kWh)

	LADWP (< 100kW)	Energy from Solar	Optimal Rate with PV System: A-2, A		A-2, B	
Optimal Rate without PV System	A-2, A	2%	$0.1279	(n=5)	$0.0925	(n=1)
		75%	-	-	$0.0763	(n=6)
		Unscaled	$0.1212	(n=2)	$0.0805	(n=4)
	A-2, B	2%	-	-	$0.1114	(n=18)
		75%	-	-	$0.0702	(n=18)
		Unscaled	-	-	$0.0760	(n=18)

Table 13. Value of PV After Rate Switching: PG&E

Value of Rate Switching (median, $/kWh)

	PG&E (< 200kW)	Energy from Solar	Optimal Rate with PV System: A-6		A-10		A-10 TOU		E-19	
Optimal Rate without PV System	A-6	2%	$0.1825	(n=5)	-	-	-	-	-	-
		75%	$0.1825	(n=5)	-	-	-	-	-	-
		Unscaled	$0.1770	(n=5)	-	-	-	-	-	-
	A-10	2%	-	-	$0.1469	(n=6)	-	-	-	-
		75%	$0.1625	(n=6)	-	-	-	-	-	-
		Unscaled	$0.1542	-	$0.1446	(n=1)	-	-	-	-
	A-10 TOU	2%	-	-	-	-	$0.1515	(n=7)	-	-
		75%	$0.1658	(n=7)	-	-	-	-	-	-
		Unscaled	$0.1595	-	-	-	$0.1557	(n=1)	-	-
	E-19	2%	-	-	-	-	-	-	$0.1414	(n=6)
		75%	$0.1629	(n=6)	-	-	-	-	-	-
		Unscaled	$0.1653	(n=3)	-	-	-	-	$0.1507	(n=3)

Value of Rate Switching (median, $/kWh)

	PG&E (200kW - 500KW)	Energy from Solar	Optimal Rate with PV System: A-6		A-10 TOU		E-19	
Optimal Rate without PV System	A-6	2%	$0.1831	(n=6)	-	-	-	-
		75%	$0.1831	(n=6)	-	-	-	-
		Unscaled	$0.1798	(n=6)	-	-	-	-
	A-10 TOU	2%	-	-	$0.1520	(n=12)	-	-
		75%	$0.1658	(n=12)	-	-	-	-
		Unscaled	$0.1579	(n=10)	$0.1523	(n=2)	-	-
	E-19	2%	-	-	-	-	$0.1414	(n=6)
		75%	$0.1629	(n=6)	-	-	-	-
		Unscaled	$0.1653	(n=3)	-	-	$0.1507	(n=3)

Value of Rate Switching (median, $/kWh)

	PG&E (> 1000KW)	Energy from Solar	Optimal Rate with PV System			
			E-19		E-20	
Optimal Rate without PV System	E-19	2%	$0.1723	(n=17)	-	-
		75%	$0.1429	(n=17)	-	-
		Unscaled	$0.1353	(n=17)	-	-
	E-20	2%	-	-	$0.1400	(n=7)
		75%	$0.1140	(n=7)	-	-
		Unscaled	$0.1223	(n=2)	$0.1465	(n=5)

Table 14. Value of PV After Rate Switching: SCE

Value of Rate Switching (median, $/kWh)

	SCE (20kW - 200kW)	Energy from Solar	Optimal Rate with PV System					
			GS-2, Non-TOU		GS-2, TOU Option A		GS-2, TOU Option B	
Optimal Rate without PV System	GS-2, Non-TOU	2%	$0.1572	(n=6)	-	-	$0.1534	(n=1)
		75%	-	-	$0.1354	(n=7)	-	-
		Unscaled	$0.1588	(n=1)	$0.1366	(n=6)	-	-
	GS-2, TOU Option A	2%	-	-	$0.1586	(n=8)	-	-
		75%	-	-	$0.1435	(n=8)	-	-
		Unscaled	-	-	$0.1445	(n=8)	-	-
	GS-2, TOU Option B	2%	-	-	-	-	$0.1194	(n=9)
		75%	-	-	$0.1311	(n=9)	-	-
		Unscaled	-	-	$0.1310	(n=6)	$0.1038	(n=3)

Value of Rate Switching (median, $/kWh)

	SCE (200kW - 500kW)	Energy from Solar	Optimal Rate with PV System			
			TOU-GS-3 Option A		TOU-GS-3 Option B	
Optimal Rate without PV System	TOU-GS-3 Option A	2%	$0.1795	(n=9)	-	-
		75%	$0.1623	(n=9)	-	-
		Unscaled	$0.1670	(n=9)	-	-
	TOU-GS-3 Option B	2%	$0.1818	(n=1)	$0.1668	(n=14)
		75%	$0.1522	(n=15)	-	-
		Unscaled	$0.1530	(n=11)	$0.1479	(n=4)

Table 15. Value of PV After Rate Switching: SDG&E

Value of Rate Switching (median, $/kWh)

	SDG&E (> 500kW)	Energy from Solar	Optimal Rate with PV System: A-6 TOU		Optimal Rate with PV System: AL-TOU	
Optimal Rate without PV System	A-6 TOU	2%	$0.1353	(n=8)	$0.1974	(n=1)
		75%	$0.1188	(n=9)	-	-
		Unscaled	$0.1293	(n=9)	-	-
	AL-TOU	2%	$0.1194	(n=1)	$0.1638	(n=14)
		75%	$0.1216	(n=14)	$0.1238	(n=1)
		Unscaled	$0.1267	(n=13)	$0.1467	(n=2)

Table 16. Value of PV After Rate Switching: SMUD

Value of Rate Switching (median, $/kWh)

	SMUD (20kW - 300kW)	Energy from Solar	Optimal Rate with PV System: GS-Demand		Optimal Rate with PV System: GS-TOU3	
Optimal Rate without PV System	GS-Demand	2%	$0.1005	(n=3)	-	-
		75%	-	-	$0.0868	(n=3)
		Unscaled	-	-	$0.0863	(n=3)
	GS-TOU3	2%	-	-	$0.1042	(n=21)
		75%	-	-	$0.0870	(n=21)
		Unscaled	-	-	$0.0903	(n=21)