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Electricity Rate Structures and the Economics of Solar PV: Could Mandatory Time-of-Use Rates Undermine California's Solar Photovoltaic Subsidies?

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Electricity Rate Structures and the Economics of Solar PV: Could Mandatory Time-of-Use Rates Undermine California's Solar Photovoltaic Subsidies?

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Abstract: In May 2007, a *Los Angeles Times* newspaper article reported that the California Solar Initiative (CSI), commonly called the "million solar roofs" program, was being hobbled by a requirement that recipients of the solar PV subsidies go on time-of-use (TOU) rates. TOU rates charge higher prices for electricity at peak demand times (primarily weekday summer afternoons in California) and lower prices at off-peak times than the more common flat-rate tariff, which imposes the same price for a kilowatt-hour (kWh) of electricity at all times. The *LA Times* story reported that orders for solar installations had dropped 78% since January 1, 2007 when the TOU-mandate went into effect for solar-rebate recipients. By June, California regulators had eliminated the TOU mandate. I examine data from a sample of 274 medium- to high-use residential customers of Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) to see if the TOU mandate makes the solar rebate program less attractive financially. Among PG&E customers, I find that the vast majority would be better off on TOU than on a flat rate tariff. For SCE customers, however, the effect of a switch to TOU is complicated by the fact that SCE's flat rates are tiered (*i.e.,* increasing marginal electricity price with greater total level of monthly consumption), but its TOU rates are not. Thus, even though solar PV production is greatest during TOU peak periods, many customers' value from the system is maximized on a flat-rate tariff. I then examine the overall economics of installing a solar PV system for these customers. The financial return to solar PV depends very much on how retail rates will change over the 20-30 year life of the panels, a very difficult path to predict. If inflation-adjusted rates were to remain at current levels, however, I find that a solar PV installation might generate a positive financial return for up to half of PG&E's medium- and high-consumption residential customers, but not for any of the SCE customers, regardless of whether they are on TOU or flat rates. Together, these results suggest that the TOU mandate is unlikely to have been a significant cause of declining demand for solar PV installations. Finally, returning to the claims in the newspaper article that demand for solar installations declined after January 1, 2007, an examination of California's solar rebate databases indicates that there was a large dropoff in orders early in 2007, but it had already rebounded before public discussion of the repealing the TOU mandate even began.

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I. Introduction

The California Solar Initiative (CSI) was adopted by the California Public Utilities Commission (CPUC) in 2006 to promote the use of solar power. About 90% of the more than $3 billion allocated to the program over 10 years is designated for rebates to customers installing solar photovoltaic panels at their homes or businesses. The rebates, however, came with some other requirements. In particular, customers were required to meet certain energy efficiency standards in their buildings and they were required to be on a time-of-use (TOU) electricity tariff. Most small commercial and nearly all residential customers in California are on flat-rate tariffs that charge the same price for electricity at all times. The TOU tariff charges a higher rate during the periods that are typically highest demand – mainly summer weekday daytime hours – and a lower rate at all other times.

The TOU tariff was thought by many to be a benefit to customers installing solar PV, because the output from the solar systems occurs disproportionately during the times that rates are high under the TOU plan. It is widely recognized that the value of a solar PV system is greater under a typical TOU rate schedule than under revenue-equivalent flat-rate pricing.[2]

In May 2007, however, a *Los Angeles Times* newspaper article set off a political firestorm when it reported that the TOU mandate was deterring most potential customers from installing solar PV.[3] The article quoted a CPUC study as showing that the demand for the systems had declined 78% following the introduction of the TOU mandate. With unusual speed and determination, the legislature, Governor, and CPUC coordinated to take action to eliminate the TOU mandate from the CSI. The CPUC investigation of the issue, however, generated very little hard evidence; opponents of the mandate submitted a few affidavits of customers who said that the requirement made installing PV less attractive. Southern California Edison responded by doing a calculation for several hypothetical customers that showed that their bills, after installing solar, would be lower under TOU than with a flat-rate tariff.[4] Based on the evidentiary record the administrative law judge recommended rescinding the TOU requirement. On June 7, 2007, the CPUC

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[2] See Borenstein (2005) for an example of such a calculation.

[3] Marc Lifsher, "Rebate Rule Chills Sales of Solar; Installers fear collapse as many homeowners choose to avoid associated higher utility costs," *Los Angeles Times*, May 8, 2007, page C1.

[4] Prior to the CPUC investigation, SCE had discovered an error in its determination of TOU rates that had resulted in all TOU rates being 10% to 20% too high. They corrected this error prior to the CPUC investigation, however. All calculations in this paper are based on the corrected rates.

commissioners voted to eliminate the TOU requirement effective immediately.[5]

While the power from a solar PV installation is generally more valuable under a TOU tariff than under a flat rate, the claim that a TOU mandate could make installing solar PV less attractive financially is not implausible for at least some customers. This is because the retail tariff determines not just the benefits from the solar PV production but also the costs of the customer's electricity consumption. Switching from a flat rate to TOU might be expected to raise the benefits the customer gets from the solar PV system, but it also changes the customer's cost of electricity absent the solar system. In particular, if a customer has disproportionately high demand (relative to the overall system demand) during the TOU peak period, then switching from flat rate to TOU (absent solar PV installation) is likely to raise its bills. Flat rate pricing essentially taxes off-peak consumption and subsidizes peak period consumption, so a customer who consumes disproportionately on peak will receive a net subsidy under flat rates. For such a customer, switching to TOU means giving up that subsidy, an effect that can more than offset the benefit from greater valuation of the solar PV electricity production under TOU.

Thus, the net effect of installing solar and switching to a TOU tariff can potentially be higher electricity costs for the customer than if she stayed on flat rates. My primary goal in this paper is to determine whether this potential outcome would actually occur, under real usage patterns and real retail tariffs, among a significant proportion of residential customers in California. I focus on residential customers, because the vast majority of customers affected by the TOU mandate are residential – larger commercial and industrial customers are already on TOU – and because the vast majority of the small solar PV systems installed by customers on flat rate tariffs are on residences. In addition, while there are many commercial tariffs that customers might be on, there is generally just one flat rate tariff structure that applies to nearly all of a utility's residential customers. So, reconstruction of the customer bills engenders less uncertainty about the price the customer faces.

Based on an analysis of 274 medium to large residential customers spread throughout the service territories of Pacific Gas & Electric (PG&E) and Southern California Edison (SCE), which covers the majority of the state's residential customers, I conclude that only about 5% of the PG&E's residential customers in the sample would be made worse off by switching to a TOU tariff after installing even a relatively small solar PV system. For SCE customers, the share is much greater: over half of the customers studied would be worse off on one of SCE's TOU tariffs. But the reason has less to do with the time-varying property

[5] The total time from the *LA Times* article to reversal of the TOU requirement was 30 days.

of the TOU tariff than with the tiered (also known as "increasing block") structure of SCE's flat rate, but not its TOU rate.[6]

Where TOU rates do increase customer bills after installing solar PV, it is relevant to figure out whether they pose a significant economic barrier to the industry. I analyze the economic costs and benefits for these customers, accounting for tax credits and rebates, as well as the timing of expenditures and savings. Estimates of savings depend fundamentally on assumptions about future level and structure of retail electricity prices. On the assumption that rates and rate structures remain at current inflation-adjusted levels, I find that roughly one-quarter to one-half of the PG&E customers in this sample would benefit from installing solar PV. Under the same assumption, however, none of the SCE customers in the sample would benefit. I then discuss the weaknesses in the constant-rate assumption and conclude that the real price of power that solar PV replaces is likely to decline over time, lowering the economic payoff of investing in solar PV today.

Finally, I return to the basic claim in the *LA Times* article that started the policy upheaval. The article reported that the database of rebate requests showed a 78% decline in applications for solar PV rebates in the first quarter of 2007 compared with the first quarter of 2006. Though the dropoff was likely not quite as great as reported in the article, it was quite significant. By April, however, demand seems to have returned to nearly the level seen under the pre-CSI rebate programs. This was before there was any public discussion of repealing the TOU mandate, so the rebound cannot be credited to a change in the TOU policy.

II. Data Sources and Analysis

The analysis of the impact of mandatory TOU pricing relies on hourly consumption data for residential consumers. Regular residential customers do not have meters that record this information, but under a 15-month pilot pricing program that was run in 2003 and 2004, the State installed meters that record consumption by 15 minute intervals in about 2000 houses and small businesses. The purpose of this Statewide Pilot Pricing (SPP) program was to examine the impact of "Critical Peak Pricing," a tariff that includes very high prices on the highest-demand days and lower prices at other times. Fortunately for the present analysis, the program also included a set of randomly chosen control group households. Most of these control group households simply remained on a flat-rate tariff,

[6] Wiser et al (2007) examine the bill savings of commercial customers from installing solar PV and also find that it is very dependent on the details of the rate structure. Hoff and Margolis (2004) study the effect of a switch to TOU rates on a hypothetical customer in Northern California with a typical load profile, but they are not able to apply the analysis to a dataset of actual customer load profiles.

so they had no change other than to have the interval meter installed. About one-third were put on a time-of-use, but not critical peak pricing, tariff.[7] These control group households are the subject of the present analysis. The control group is drawn from all parts of the service territories of the three investor-owned utilities in California, though it somewhat oversampled high-use single-family customers and households in hot climate zones. The SPP also did not include households with self-generation facilities, so none of the participants had solar PV.[8]

I focus on single-family control-group residences in the PG&E and SCE service territories for which there are hourly consumption data for the twelve-month period September 2003 through August 2004.[9] I present the analysis with and without the TOU customers that were in the control group, though the conclusions are unchanged by their exclusion.

Based on their consumption data, a flat-rate and TOU bill is calculated for each customer for each month of the sample period using the relevant tariff of the utility that serves the customer. The purpose of this calculation, before introduction of any solar PV system, is to see how much the customer's bill would change with a shift from flat rate to TOU. That is, compared to the time-varying TOU tariff, how much is the customer gaining or losing by being on a flat-rate tariff. Because the ultimate point is to look at the effect of TOU with a solar installation, the TOU bills are calculated using the tariff that is designated for use by customers with solar PV systems.

It is important to point out that the bills are calculated taking the household consumption as independent of the tariff. To the extent that customers change their consumption in response to switching from a flat to a TOU tariff, this approach would somewhat overstate the bill increase, or understate the bill decrease, of a switch to TOU. With the typical estimated elasticities this effect is likely to be small and would not change the basic conclusions, but future work could incorporate a non-zero demand elasticity assumption.[10]

After calculating the customers' bills without a solar PV system, I then recalculate their bills under each tariff with a hypothetical solar installation. The concern that led

[7] These control households were also paid to participate, so the acceptance rate was very high.

[8] For more details on the SPP, see Charles River Associates (2005) and Letzler (2007).

[9] I drop the first 3 months of the study, when data collection was less consistent. I exclude all apartment dwellings and low-use single-family residences, as detailed below.

[10] Conversely, if the observed customer is actually already on a TOU tariff and consumption has been optimized for that tariff, then the calculation would somewhat understate the bill increase from a flat-to-TOU switch.

to repeal of the TOU mandate was that customers who installed small systems that do not generate sufficient power to cover the household's peak period consumption would be made worse off by the TOU switch. So, I consider a relatively small 2kW (DC) system for these households. Using simulated production from three locations in California, each household is assigned a PV production for each hour from the location that most closely matches theirs in climate and geography. The customer bills under TOU and flat rate service are then recalculated for the net consumption the household still purchases from the utility.

The simulated solar PV production data are from the TRNSYS (A Transient System Simulation Program) program developed at University of Wisconsin and based in Madison.[11] I obtained TRNSYS simulated production for solar PV systems installed in San Francisco, Sacramento, and Los Angeles.[12] For each location, the runs were done assuming the panels were mounted at a 30 degree angle facing, in different runs, South, Southwest, and West. I use the data for South-facing panels, because most installations attempt to direct the panels south to maximize output and because this maximizes the customer's value from the panels. On average, this assumption probably overstates the value of the solar system somewhat.

Weather data for TRNSYS come from the U.S. National Renewable Energy Laboratory (NREL). The weather dataset is TMY2, which is described by NREL as, "[t]he TMY2s are data sets of hourly values of solar radiation and meteorological elements for a 1-year period. Their intended use is for computer simulations of solar energy conversion systems and building systems to facilitate performance comparisons of different system types, configurations, and locations in the United States and its territories. Because they represent typical rather than extreme conditions, they are not suited for designing systems to meet the worst-case conditions occurring at a location."[13]

The TRNSYS model produces hourly simulated production data for one year. I match the days of the TRNSYS year with the same days of the period September 2003-August 2004. The TRNSYS solar PV production data have substantial day-to-day variation,

[11] See http://www.trnsys.com/ .

[12] I'm grateful to Duncan Callaway for doing the TRNSYS runs that produced the simulated PV production. The three locations are not exhaustive coverage, but they suggest that more detailed location data would not substantially change the results. The average DC capacity factors over the year are 19%, 19% and 20% for San Francisco, Sacramento, and Los Angeles, respectively, and the correlation of hourly production is 0.87 to 0.90 across the three locations.

[13] See description on NREL website http://rredc.nrel.gov/solar/old_data/nsrdb/tmy2/ .

reflecting weather variation.

Appendix A presents the details of how monthly bills were calculated by combining the electricity consumption (or net electricity consumption after solar PV production) with the utilities' retail residential flat-rate and TOU tariffs. Issues that arise include assignment of baseline quantities based on customer locations, allocation of baseline between peak and off-peak periods under TOU, baseline credit rebates, method of net metering credit calculation for excess solar PV production, assignment of simulated solar PV production based on customer location, and selection of TOU tariff among those available to the customer. In all cases, I have attempted to make reasonable assumptions that would not bias the analysis in one direction or another. Still, further analysis of this kind using a larger dataset and more customer details than I have access to, would certainly be appropriate. Nonetheless, the results of this analysis yields valuable information that seems to have been rather scarce during the May/June 2007 policy upheaval.

For each customer, the analysis produces annual electricity bills under flat and TOU tariffs with and without an assumed 2kW (DC) solar PV installation. The next section compares these bills for various subsets of the data to examine the economic incentives that the now-repealed TOU mandate could have produced.

III. The Effect of TOU tariffs on the Residential Incentive to Install Solar PV

Table 1 presents a basecase analysis of bills under alternative tariffs. The basecase includes all customers in the SPP control groups who had total annual consumption of at least 6000 kWh, an average of at least 500 kWh per month. This approximately corresponds to 130% of baseline consumption for the average customer, the level below which tariffs have been designed to protect customers from rate increases since the 2000-01 electricity crisis. I limit the analysis to customers above this level for two reasons: (1) the complaints about TOU in May/June focused on larger-consumption households who did not install enough PV to cover their peak consumption and (2) solar PV is extremely unlikely to be economic for low-consumption households because they face relatively low per-kWh marginal prices for electricity, due to the tiered (*i.e.,* increasing block) residential rate structures.

The top panel of Table 1 examine the data for 163 PG&E customers, comparing their bills under the standard flat-rate residential tariff and PG&E's TOU tariff intended for use by solar PV owners. It it immediately evident from the "Bill Levels" section of the table that, with or without the solar installation, the TOU tariff offers lower total bills for most of these customers than the flat-rate tariff.[14] The third line of the "Bill Changes" section confirms this. For a customer with no solar PV installation, the mean annual savings from being on a TOU tariff is $124 among these customers, and the median savings is $112. Only 10 of the 163 customers in this sample would be better off on the flat-rate tariff. Table 1A shows that results are consistent for the group of larger customers, those consuming at least 10000 kWh in the year (833 kWh per month). Table 1B shows that the results are very similar if one examines only the control group customers who were on a flat-rate tariff, excluding those on TOU. Thus, among at least this sample of PG&E customers, there are very few customers who would be made worse off by a switch to TOU, even without a solar PV installation.

While the third line of the "Bill Changes" section presents the flat versus TOU comparison for a customer assuming no PV installation, the fourth line presents results accounting for the simulated production from a 2 kW(DC) PV system that the customer is assumed to have installed. As expected, the relative advantage of the TOU tariff compared to flat rate is on average larger for customers if they have solar PV installations. The mean and median benefit of the TOU tariff both increase by about $20 per year, and the number of customers who would pay less under a flat-rate tariff declines to 6 out of 163. Again, Tables 1A and 1B show that limiting the sample to higher-consumption customers or to just those actually on a flat-rate tariff does not substantially change these findings.

Though the small sample suggest some caution in interpreting these results, it seems very likely that PG&E's TOU rates benefit nearly all customers installing solar PV systems compared to the flat-rate tariff that these PG&E customers would otherwise face. These results suggests that the TOU mandate reduces the benefits of solar PV installation for only a small fraction of PG&E's residential customers.

The results for PG&E, however, do not carry over to Southern California Edison customers. Analysis of incentives for SCE customers is somewhat more complicated, because SCE offers two different TOU rates from which a residential customer with solar PV can choose. One is targeted towards medium-sized customers (4800-7200 kWh per year) and the other towards large customers (over 7200 kWh per year). Ideally, every customer would choose the tariff that results in the lowest bill, but realistically that won't happen in every case. I use two cases to bound the effect of TOU: the "TOU-min" bills are based on the assumption that each customer picks the TOU tariff that gives him/her the lowest bill while "TOU-avg" assumes that a customer chooses randomly between the two TOU tariffs and in expectation receives the average of the bills that the two different rates would generate.

[14] To preserve confidentiality of outlier observations minimum and maximum bill levels are not shown.

In reality, customers won't be so well informed that they all achieve TOU-min, but won't be so uninformed that they do no better than choosing randomly between the two available tariffs. Given the simple rule available for choosing the preferred tariff, based on the customer's annual consumption, TOU-min is probably a better guide to actual outcomes. Luckily, the difference between these approaches is actually fairly small, with TOU-min bills averaging about 2% lower than TOU-avg bills. As a result, I base subsequent analysis on TOU-min, which is referred to as simply TOU in subsequent tables and discussion.

The first three lines of the "Bill Levels" section of the lower panel in Table 1 present flat and TOU bills without a solar installation. While the mean bills are quite close, the variation across customers is markedly different. In particular, the largest users benefit from TOU and the smaller users are harmed. This outcome is the direct result of the fact that SCE's TOU rates do not have the tiered (increasing-block) price structure that the flat-rate tariff does. The TOU tariff has peak and off-peak rates that, unlike PGE's TOU tariff, are not affected by how much electricity the customer consumes. Thus, an SCE customer who switches from a flat rate tariff that has five rate tiers – increasing with the customer's total consumption – to a TOU tariff with no rate tiering is likely to see a bill decrease if she had a high consumption level that caused much of her electricity to be billed at very high retail rates.

The effect of this curious structure – under which the flat-rate tariff, but not TOU, incorporates increasing-block tiers in the rates – is a narrowing of bill variation across customers due to the TOU switch. High-consumption customers are very likely to benefit from a switch to TOU and low-consumption customers are very likely to lose. Comparison of the first line of "Bill Levels" in Table 1 with the second and third line illustrates the magnitude of this effect. The impact of this structure is that the largest customers in this sample (a sample already limited to customers averaging at least 500 kWh per month) benefit quite significantly from a switch to TOU while the smallest customers in the sample are significantly harmed. Overall, just over 60% of these customers (71 or 72 out of 111) would be harmed by a switch to TOU in the absence of a solar PV system.[15]

The complex effect of tying the flat/TOU choice to a tiered/non-tiered structure is even more surprising when we add a simulated 2 kW solar PV system to these customers. TOU rates are supposed to be favorable to solar, but an even larger proportion of these customers would receive lower bills with flat rates *after* installing solar than *before* installing solar. The result may seem puzzling, but it follows from the tiered rates associated with

[15] In none of the households in the SCE or PG&E dataset would installation of solar PV and switch to a TOU tariff actually increase electricity bills, as some news reports have suggested.

the flat-rate tariff, but not the TOU. Tiering of only the flat rate tariff can cause it to result in lower *overall* bills, due to low prices from the first tranche of consumption, and still have higher *marginal* power rates for consumption. Since the value of solar PV is in the consumption it eliminates on the margin, adding solar can actually make the tiered, flat-rate tariff even more attractive compared to the untiered, TOU tariff. Put somewhat more broadly, the TOU rate places a high value on the solar production at peak times that replace peak consumption from the grid, but a tiered rate can put a high value on all of the solar PV substitution from grid consumption for a high-consumption household.

This points out a real concern with retail rate design, particularly the perverse effect of rate tiering when applied to some, but not all, tariffs from which a customer can choose. It would not be appropriate, however, to interpret these results as suggesting that TOU rates in themselves harm customers who install solar PV. The PG&E rate structure doesn't conflate the TOU/flat distinction with the tiered/non-tiered distinction and avoids the consequences of the SCE structure.

IV: Calculating the Customer's Net Financial Benefit from Solar PV

Many rules of thumb have been suggested for calculating whether installing solar PV will make a customer financially better off. Some rules are reasonable approximations while others are clearly misleading.[16] In this section, I start from the basic economic calculation and isolate the important factors that will affect the customer's net benefit from installing solar PV.

Central to an evaluation of solar PV is recognition of the time value of money, which causes costs or benefits that occur in the future to be less valuable than ones that occur today. This is true of all cost/benefit analyses, but particularly salient for solar PV because it is a long-lived investment with high capital costs paid up front and very low operating costs once the panels are installed. Thus, the interest rate used to discount future costs and benefits will be particularly important in driving the results.

One can start by calculating the lifetime (inflation-adjusted) levelized cost per kWh of power the panels will produce. There are data on the cost of installing solar PV systems because the rebates that the State offers require the customer to report the installation cost. For illustration, recent data suggest for a 2kW (DC) system an installation cost of $8.50/watt DC or $17,000 total is a reasonable – possibly somewhat optimistic – estimate.

[16] Unfortunately, one of the most common approaches, calculating the payback period for the investment and comparing it to the life of the panels, nearly always suggests the investment is worthwhile even when it is not.

Actual cost will vary by location and over time, but this is a reasonable starting point for this illustration.

The customer, however, receives two substantial government incentives that reduce the final cost. First, the California Solar Initiative offers a rebate of \$2.50/watt AC, or about \$2.25/watt DC.[17] Second, the federal government offers a \$2000 tax credit.[18] So, in this illustration, the cost after the state rebate of \$4500 and the federal tax credit of \$2000 would be \$10,500.

After installation, the largest cost that the owner of a solar PV system is expected to face is for replacing the inverter. Median time-to-failure estimates for inverters range from 5-10 years, so I assume 8 years, which implies that the inverter will have to be replaced twice over the assumed 25-year life of the panels, assumed to occur in years 8 and 16. Current inverter cost for a 2kW system is in the range of \$1600, but that is likely to decline over time. Inverter costs are assumed to decline by 2% per year in real terms, consistent with a study by Navigant consulting (2006) for National Renewable Energy Laboratory.[19]

Putting these costs together and discounting the cost to the present yields a net present cost of the system, which is then amortized over the lifetime of power produced. The net present cost and the amortization depend on the real interest rate assumed. The appropriate interest rate is the after-tax real cost of funds because it will then be compared with the savings from reduced electricity bills, savings that are recovered from after-tax payments. Depending on the customer's source of funds – savings or debt – and his/her tax bracket, the appropriate rate could easily be as low as 3% and as high as 7%. Table 2 presents cases for 3%, 5% and 7% after-tax real interest rate.

The net present cost of a solar PV system can then be amortized over the lifetime of production to arrive at a lifetime real cost per kWh produced. Studies of solar PV production over a panel's lifetime suggest two adjustments from the TRNSYS simulation figures used in the previous sections. The first is the aging effect: PV cell production declines over time, with the best estimates in the range of 1% of original capacity per year. The second is the "soiling" effect: dirty solar panels absorb less solar radiation

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[17] The California Energy Commission estimates the power lost in the DC-to-AC conversion based on the model of inverter. A 10% loss is about typical in the CEC estimates.

[18] The credit is 30% up to \$2000, but for any normal size system the \$2000 limit is binding.

[19] I assume that otherwise the panels perform flawlessly over their 25 year life. To the extent that there is more maintenance required, that obviously increases the total cost.

and generate less electricity. There is a whole literature on the impact of soiling, which concludes that it depends on idiosyncratic factors, like amount and density of rainfall, and on endogenous factors like maintenance effort.[20] Table 2 adjusts for the aging effect, but not for soiling.

The cost per kWh is then calculated by finding the constant real cost per kWh in every year that sets the net present value of the power produced equal to the net present cost of the installation and inverter replacement cost. The results for a 5% real interest rate can be interpreted as saying that installing solar PV in 2007 is equivalent to buying the flow of delivered AC power it will produce over the following 25 years at a constant real price of 32.2¢ per kWh.[21] Using a nominal interest rate of 0% (a real interest rate of about -2%), which is the unfortunately common practice of ignoring the time value of money, yields a cost of about 17.1¢ per kWh and makes solar PV *appear* much more economical.

So, assuming that the panels last for 25 years, stay clean and operate smoothly with only the need for two inverter replacements, the amortized real cost of the power they produce to the customer, after rebates and tax credits, is likely to be between 27¢ and 37¢ per kWh depending on the buyer's cost of financing.

This cost of PV power should then be compared with the present value of the bill savings that the customer will receive as a result of his or her reduced demand from the grid. Unfortunately, that requires a prediction of the tariffs that the customer will face over the life of the panels and the customer's demand over that period. Speculating over the future of California electricity rate levels and rate design is not likely to be very reliable.

Purely as a starting point, we can compare the amortized cost per kWh of the PV power to the price per kWh that the customer would have paid on that power if it were purchased from the utility under the current tariffs. Table 3 presents the distribution of savings per kWh that customers in the PG&E and SCE samples would receive from having solar installed under the current tariffs.

As with Table 1, Table 3 shows that nearly all PG&E customers get greater benefit from solar PV if they combine it with a switch to the utility's solar TOU rate, a TOU rate that is currently only available to customers with solar and other on-site generation.[22]

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[20] See, for instance, Hammond et al (1997) and Kimber et al (2006).

[21] An assumption of no degradation of production over time, rather than 1% per year, lowers the cost to about 28.9¢ per kWh.

[22] PG&E does offer another TOU rate (E-6) for other customers, but it is not particularly attractive.

With that switch, the mean and median savings are close to the middle of the distribution of possible solar PV costs, so for about half of this sample the amortized cost of the solar PV power is likely to be greater than the bill savings under the current tariff. For about a quarter of these customers, the savings are greater than the high end of the cost distribution, suggesting that under the current tariff these customers would very likely see savings greater than the amortized cost of the solar PV power. To put this in perspective, if a customer can consistently save ten cents per kWh with the solar PV power – the difference between the amortized cost of the PV power and price per kWh that would have been paid to the utility for that power – that will amount to about $300/year for a typical customer in this sample.

For SCE customers, Table 3 indicates a much less favorable picture for solar PV. The cost of installing solar is not substantially different in SCE than PG&E territory (and is assumed to be the same for this calculation), but the savings are likely to be lower for SCE customers. The main driver of this is that both SCE's current tiered flat-rate structure and its untiered TOU rate do not charge as high rates for even the heaviest users as does PG&E. SCE's flat-rate tariff tops out at about 30¢ per kWh for the highest tier, while PG&E's tariff goes up to over 36¢ per kWh. Thus, SCE customers on the current flat-rate tariff are displacing less expensive retail power than are PG&E customers when their solar PV generation replaces top-tier consumption. As a result, only about a quarter of the SCE customers studied would have savings that are in the possible range for a net savings from solar PV, even if they stayed on flat-rate tariffs.

Even that, however, overstates the economic attractiveness of solar PV for SCE customers. All of the SCE customers for whom solar PV appears potentially attractive under a flat-rate tariff shouldn't be on a flat-rate tariff even if they don't install solar. These are all high-consumption households that would be better off choosing a TOU tariff. In fact, if one looks at the savings of these customers if they are on TOU before and after installing solar PV, the 90th percentile savings is $0.228 and the maximum is $0.229, well below the range of plausible costs of the solar PV power. More generally, if one assumes that the customer chooses the best (*i.e.,* cost-minimizing) tariff for his/her consumption both before and after installing solar, the last line of Table 3 shows that the maximum savings is $0.264 per kWh under the current tariff, below the range of solar PV costs.[23]

Of the 163 customers in this sample, only 4 would have lower bills on the E-6 tariff than on the flat-rate tariff.

[23] These calculations have all been carried out for a relatively small 2 kW system. The per kWh savings from a larger system would be lower because the additional power generated would be replacing retail purchased power from a lower rate tier, on average.

The phrase "under the current tariff" appears repeatedly in the previous paragraphs because the analysis is comparing the amortized cost of a sunk 25-year solar PV investment to a retail electricity tariff that will surely change many times over that period. The analysis in the previous paragraph is sufficient only if power prices will retain their current tariff structure and will rise at the rate of inflation over the 25 years. Two factors make it unlikely that will be a reasonable approximation.

First, the extremely high *marginal* electricity prices that PG&E's larger residential users face are well out of the norm both nationwide and historically in California. The same is true for SCE's customers on the flat-rate tariff. The marginal rate paid by the largest residential customers is more than twice the average rate paid by all of the customers in the control group. If that over 2-to-1 ratio were to return to historical norms of 1.2-to-1 or 1-to-1, while overall real average power prices remained at current levels, the chances are that none of the customers in this sample would benefit from installing solar PV.

Second, the real *average* retail power price is likely to change over the next 25 years. Two factors will pull in opposite directions. On the one hand, California's current prices are well above the wholesale price of power because they include expensive power that was purchased under long-term contract, and other commitments made, during the electricity crisis. On the other hand, the cost of fossil-fuel based power is likely to rise as the greenhouse gases associated with the power becomes more expensive to emit (either explicitly through a tax or implicitly through a cap-and-trade system or other emissions restriction). While the cost of fossil-fuel generation is likely to rise over time, other alternative energy sources – many of which are already significantly less expensive than solar PV – are likely to decline in cost, as is solar PV itself.

Thus, the customer economics on solar PV in California today, with state subsidies and federal tax credits, still rely on a fairly aggressive prediction of future marginal electricity prices. Assuming that the non-energy component of retail prices – including transmission, distribution, public goods charges, and other costs – continues in real terms at the current level of around seven cents per kWh, the economics of PV remain favorable only if either

1. wholesale electricity prices rise to around 20¢/kWh ($200 per MWh) in 2007 dollars, or
2. the retail tariff continues to have a very steep increasing block structure so the heaviest power users are paying marginal prices that are well above the average price.

Actually, if solar installations put in place today turn out to generate a positive return for the customer it will probably be a result of some combination of these two factors.

Realistically, wholesale electricity prices are unlikely to get close to the 20¢/kWh level from their recent level around 5¢/kWh. That would require not only a price on greenhouse gasses of more than $150/ton – a level that few think economically or politically feasible – but also the failure of other less expensive forms of renewable energy to make significant penetration in the market, including other solar electricity technologies. If wholesale prices get up to averaging 10¢/kWh ($100 per MWh), the marginal electricity rate would still have to be more than 50% above the average rate for the investment in solar PV today to possibly pay off. That is, a steep increasing block rate structure would have to remain in place.

V: Did TOU Rates Actually Undermine the California Solar Initiative?

The claim in the May 8, 2007 *LA Times* article that launched the policy scramble and resulted in repeal of the TOU rate mandate on June 7, 2007 was that the solar PV industry had collapsed after January 1, 2007 due to the TOU mandate. On a pure economic basis the claim that TOU reduced the incentive to install PV does not seem to be well founded. Factors other than pure economics affect demand for PV, however. For instance, some in the industry argued that the TOU requirement discouraged buyers because it created more uncertainty about future electric bills. Thus, sorting out the actual data on new orders is still important. Unfortunately, it is not at all easy to do.

The databases that were the source of the *LA Times* article suffer from many flaws and inconsistencies. The databases reflect applications for rebates under California's old and new (CSI) solar rebate programs. Timely administration and updating of these databases does not seem to have been a top priority. That may be a completely reasonable policy decision given the budget constraints of the oversight agencies, but it is still important to recognize in interpreting the data.

For the period prior to 2007, it appears that data were often added after long lags and the "approved" dates may be long after actual submission of the rebate application, so the demand calculations for specific periods of previous years that are based on these data are not really reflective of the reported periods.[24] For instance, "new" rebate approvals for the programs that ended December 31, 2006 continue to show up in the database for those programs at least into July 2007 even though new applications were not accepted in 2007. In fact, the database indicates more than twice as much capacity was approved in the first quarter of 2007 (when the program had been discontinued) than in the fourth quarter of

[24] Publicly available data for the pre-2007 rebate program do not include a "date received" field for the applications, just a "date approved" and "date complete."

2006 (the last quarter in which it was operational). Thus, the apparent comparison of first quarter 2007 orders under the new CSI program to first quarter of previous years under the old rebate programs is a rough estimate at best.

Nonetheless, there does seem to have been a very noticeable dropoff in orders right after the CSI program began on January 1, 2007. If one takes all installations 10kW and smaller (to proxy for residential and small commercial installations that might be affected by the TOU mandate) that were approved under the pre-2007 programs from April 2005 to July 2007 and assume that represents all applications submitted in calendar years 2005 and 2006, the average is 2109 kW of capacity per month.[25]

In contrast, under the new CSI program, rebate applications for systems of 10 kW or less totaled 84 kW capacity in January 2007, 416 kW in February, and 1351 kW in March.[26] These are much lower than the average over the previous two years, but the trend is clearly upward even in the first quarter. Discussions with staff from the utilities and organizations managing the program, representatives of the solar PV industry and analysts at the oversight agencies suggest that this was likely due to many factors other than the TOU mandate, including (1) customer and installer unfamiliarity with the new program requirements, (2) greater paperwork and other application requirements, and (3) a big push in late 2006 to close deals under the old program, which offered richer rebates and fewer eligibility requirements. This last factor led to the large backlog in processing rebate applications from the pre-2007 program, which lasted until at least July 2007. It also very likely cannibalized sales in early 2007.

The argument that TOU pricing caused the early 2007 dropoff also appears to be undermined by data for the second quarter of 2007, most of which were released after the *LA Times* article was published. The most recent dataset, released July 17, 2007, is

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[25] The calculation is based on the California Energy Commission's Emerging Renewables database (http://www.energy.ca.gov/renewables/emerging_renewables/index.html) using the spreadsheet "Data Showing Approved and Completed Systems After January 1, 2005 (updated: July 6, 2007)" available at
http://www.energy.ca.gov/renewables/emerging_renewables/COMPLETED_SYSTEMS.XLS.
The calculation includes all "Photovoltaic" systems 10 kW and smaller systems with approved date after 4/1/05 and with status "Reservation Approved" (3140 systems), "Payment Request Received" (795), "Payment Claim Processed" (12,989) or "Extension was granted" (4). The April 2005 start date for this summation is meant to proxy for an average 3-month approval lag. If one assumes a 6-month lag in 2005, the figure would be 2018 kW per month, while if one assumes no lag at the beginning of 2005 (but still recognize the many projects processed in 2007 that were 2006 orders), the figure would be 2313 kW per month.

[26] These and all calculations for the CSI program are based on the CSI trigger tracker spreadsheet at http://www.sgip-ca.com/CSI_Statewide_Data_17JULY07.xls. Totals for time periods are based on the "Date Received" field and exclude all projects listed as "Canceled," "Rejected," or "Withdrawn."

somewhat less informative for second quarter 2007, because it includes some applications still "under review," for that period: a small share for April, but an increasing share in later months. It is unclear what share of the "under review" are eventually approved, but comparison of a May 2007 dataset with the July 2007 dataset suggests that the great majority of those "under review" at the time of the May data release were approved by the time of the July data release.

In the July 17, 2007 dataset, the data for April 2007 indicate that new rebate applications reached between 1866 kW and 1907 kW, where the lower number excludes all "under review" and the higher number includes them all. Thus, before there was any public suggestion of repealing the TOU mandate, it appears that orders were nearly up to the average level of the previous two years. In May 2007, rebate applications were between 1258 kW and 2909 kW. The much larger range is because a much greater share of these more recent applications were still "under review" as of July, when the data were released. Nonetheless, if even half of these "under review" are eventually approved, the numbers for May are about equal to the average in the prior two calendar years. One might argue that the building political pressure to repeal the TOU mandate boosted demand in the last part of May, but the data don't indicate a strong surge in the last half of May compared to the first half. In fact, including the under review applications (to avoid bias *against* the more recent period), applications were nearly the same in the two halves of May.[27] Data for June applications are even more preliminary, but the range of rebate applications is 540 kW, excluding "under review", to 2809 including them. Final numbers for June look likely to be in the same range as May, though possibly somewhat lower, which would not be consistent with the argument that lifting the TOU mandate would boost solar PV demand.[28]

Finally, in the *LA Times* article, complaints about the TOU requirement and the dropoff in demand focused on Southern California Edison. If the problem were especially significant in SCE territory, one would expect applications there would have been hit the hardest at the beginning of 2007 and not return to pre-2007 level until at least June, after the TOU mandate was removed. In fact, SCE's share of total rebate-eligible capacity for systems 10 kW and smaller was 24% for orders under the previous program that were approved in second quarter 2005 and beyond (continuing into 2007). Its share of rebates

[27] The difference changes signs depending on whether the small number of applications received on May 16, the middle day of the month, are assigned to the first half or second half of the month.

[28] Discussions with utility staff maintaining the database suggest that the "date received" field in the CSI database is accurate. There may still be lags in processing, but this date accurately reflects when the application for rebate was received.

under the CSI was 19% in the first quarter of 2007. This decline might very well be related to the miscalculated SCE TOU rates that were 10%-20% too high at the beginning of 2007, but were corrected by April. Using the data that include "under review" rebates, SCE's share was 24% in April 2007, 23% in May, and 25% in June.[29] It appears that sales in SCE territory did drop off somewhat more than in the other two utility territories, but by April – before any public discussion of repealing the TOU mandate – the share of solar PV rebate applications in SCE territory had returned to its average level prior to the start of the CSI.

VI: Conclusion

The rapid shift of policy on requiring time-of-use pricing for CSI rebate recipients was founded on the belief that the TOU requirement was undermining demand for solar PV. On an economic basis, there seems to be little reason to think a TOU mandate would discourage solar PV investments. PG&E's TOU tariffs reward nearly all customers who would consider installing solar PV. Overall, some PG&E customers might save money by installing solar PV – if rates stay at least as high as they currently are – but they will save more on the TOU tariff than on the flat-rate tariff. SCE's TOU tariff presents some design issues that make it much less attractive for smaller-use households, but gives large windfalls for high-use households. Under either SCE's TOU or flat-rate tariff, however, the currently available solar PV technology at the currently available prices is not likely to save money for any residential customers. SCE's prices just are not high enough to make solar PV an economically viable substitute. The actual data on demand for solar PV installations in California also does not appear to support the conclusion that the CSI's TOU mandate significantly harmed demand. Demand for solar PV did drop substantially at the beginning of 2007, concurrent with the launch of the CSI, but it seems to have rebounded by April, before there was serious discussion of repealing the TOU mandate. The early-2007 decline was likely a result of unfamiliarity with the new program, other applicant requirements, and a push to increase sales at the end of 2006 that probably shifted some sales forward in time.

[29] Excluding "under review" applications, the share was 24% in April 2007, 41% in May, and 58% in June. The latter two figures probably reflect faster rebate reviewing by SCE than in the other territories, not an explosion of orders in SCE territory or collapse elsewhere, leading to an SCE share much higher than even under prior programs.

Appendix A: Calculation of Residential Bills

Calculation of customer bills followed the filed tariffs of each of the utilities. For PG&E, the relevant tariffs and their locations are:
flat-rate tariff: http://www.pge.com/tariffs/pdf/E-1.pdf
and TOU rate: http://www.pge.com/tariffs/pdf/E-7.pdf .
For SCE,the relevant tariffs are:
flat-rate tariff: http://www.sce.com/NR/sc3/tm2/pdf/ce12-12.pdf
and two TOU tariffs:
http://www.sce.com/NR/sc3/tm2/pdf/ce84-12.pdf and
http://www.sce.com/NR/sc3/tm2/pdf/ce55-12.pdf .
These have been preserved as of the time of this research in case they change or become unavailable. They are collected in one document and are available from the author.

For each utility, the customer baseline depends on the customer's location. The SPP data do not include addresses, only weather regions. Each of the 16 weather regions of PG&E customers and 23 weather regions of SCE customers in the SPP dataset was assigned to a customer baseline region of the relevant utility. The customer baseline region determines the customer's baseline consumption quantity, which also varies between winter and summer time periods.

In all cases, minimum daily bills were exceeded by actual bills, so minimum daily bills were not used. Daily meter charges were added to the bills where they existed. Bills were calculated on a calendar-month basis. In the case of PG&E, the filed tariff is sufficient for exact calculation of the residential bill. In the case of SCE, the exact calculation varies slightly according to the mix of power coming from utility-retained generation (URG) and contracts assigned from the Department of Water Resources (DWR). SCE bills were based on an assumption of a mix of 75% URG and 25% DWR, which is approximately accurate, though actual shares vary daily (see
http://www.sce.com/AboutSCE/Regulatory/tariffbooks/ratespricing/dailydwr/).

Solar PV power production was based on the TRNSYS simulations of PV production for San Francisco, Sacramento, and Los Angeles, as described in Borenstein (2005). Production was scaled down proportionally to reflect a 2kW system, rather than the 10kW system that was simulated. All SCE customers were assigned the PV production of the simulated Los Angeles installation. Among PG&E customers, those in hotter areas (defined as summer baseline above 10 kWh per day) were assigned the PV production of the Sacramento installation, while those in other areas were assigned the PV production of the San Francisco installation.

Despite the small scale of the assumed PV installation, some customers did exhibit negative monthly consumption so the "net energy metering" protocols were relevant. Customer credits were calculated based on the lowest-tier retail rate for those on tiered rates. For customers on TOU rates, the net energy and associated credit was calculated separately for peak and off-peak periods. None of the customers analyzed in this study (minimum total annual consumption of 6000 kWh) had a net negative bill – which would cause forfeiture of the excess credit – when summed over the entire year.

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TABLE 1: Bill Levels and Changes Under Alternate Tariffs and Solar PV Installations
(includes all single-family households in SPP control groups with annual consumption above 6000 kWh)

PG&E	*BILL LEVELS*										
	Solar PV	Number of				PERCENTILES					
Tariff	size (DC)	Customers	Mean Bill		10th	25th	50th	75th	90th		
Flat	0 kW	163	$2,095		$1,038	$1,288	$1,800	$2,628	$3,610		
TOU	0 kW	163	$1,971		$932	$1,213	$1,662	$2,494	$3,479		
Flat	2 kW	163	$1,397		$518	$737	$1,069	$1,781	$2,734		
TOU	2 kW	163	$1,254		$402	$590	$920	$1,572	$2,532		
PG&E	*BILL CHANGES*										
From	To		Mean Change	Min	10th	25th	50th	75th	90th	Max	# > 0
Flat-0 kW	Flat-2 kW	163	-$697	-$1,010	-$945	-$843	-$681	-$563	-$455	-$344	0
TOU-0 kW	TOU-2 kW	163	-$717	-$1,029	-$970	-$867	-$703	-$583	-$474	-$363	0
Flat-0 kW	TOU-0 kW	163	-$124	-$493	-$253	-$174	-$112	-$57	-$16	$108	10
Flat-2 kW	TOU-2 kW	163	-$144	-$512	-$272	-$195	-$133	-$74	-$34	$89	6
Flat-0 kW	TOU-2 kW	163	-$841	-$1,464	-$1,165	-$1,030	-$822	-$679	-$536	-$405	0
SCE	*BILL LEVELS*										
	Solar PV	Number of				PERCENTILES					
Tariff	size (DC)	Customers	Mean Bill		10th	25th	50th	75th	90th		
Flat	0 kW	111	$2,305		$1,095	$1,373	$1,809	$2,882	$3,998		
TOU-min	0 kW	111	$2,253		$1,407	$1,574	$2,005	$2,686	$3,377		
TOU-avg	0 kW	111	$2,305		$1,430	$1,592	$2,034	$2,717	$3,507		
Flat	2 kW	111	$1,626		$571	$757	$1,137	$2,101	$3,136		
TOU-min	2 kW	111	$1,644		$771	$923	$1,369	$2,100	$2,812		
TOU-avg	2 kW	111	$1,698		$843	$979	$1,430	$2,107	$2,893		
SCE	*BILL CHANGES*										
From	To		Mean Change	Min	10th	25th	50th	75th	90th	Max	# > 0
Flat-0 kW	Flat-2 kW	111	-$698	-$862	-$844	-$795	-$674	-$582	-$514	-$388	0
TOUmin-0 kW	TOUmin-2 kW	111	-$609	-$662	-$657	-$645	-$614	-$565	-$565	-$560	0
TOUavg-0 kW	TOUavg-2 kW	111	-$607	-$614	-$614	-$614	-$613	-$604	-$591	-$557	0
Flat-0 kW	TOUmin-0 kW	111	-$52	-$2,580	-$782	-$259	$126	$277	$340	$636	71
Flat-0 kW	TOUavg-0 kW	111	-$1	-$2,190	-$632	-$174	$146	$300	$367	$652	72
Flat-2 kW	TOUmin-2 kW	111	$18	-$2,322	-$490	-$30	$132	$239	$298	$581	81
Flat-2 kW	TOUavg-2 kW	111	$73	-$1,980	-$423	-$1	$175	$303	$347	$637	83
Flat-0 kW	TOUmin-2 kW	111	-$661	-$3,145	-$1,347	-$830	-$515	-$356	-$286	-$10	0
Flat-0 kW	TOUavg-2 kW	111	-$607	-$2,804	-$1,245	-$788	-$457	-$296	-$226	$46	1

Table 1A: Bill Levels and Changes Under Alternate Tariffs and Solar PV Installations
(includes all single-family households in SPP control groups with annual consumption above 10000 kWh)

PG&E	*BILL LEVELS*										
	Solar PV	Number of					PERCENTILES				
Tariff	size (DC)	Customers	Mean Bill		10th	25th	50th	75th	90th		
Flat	0 kW	79	$2,932		$1,829	$2,065	$2,648	$3,521	$4,391		
TOU	0 kW	79	$2,779		$1,685	$1,894	$2,509	$3,267	$4,187		
Flat	2 kW	79	$2,108		$1,150	$1,259	$1,781	$2,569	$3,400		
TOU	2 kW	79	$1,935		$1,004	$1,143	$1,576	$2,362	$3,198		
PG&E	*BILL CHANGES*										
From	To		Mean Change	Min	10th	25th	50th	75th	90th	Max	# > 0
Flat-0 kW	Flat-2 kW	79	-$825	-$1,010	-$980	-$929	-$835	-$729	-$661	-$570	0
TOU-0 kW	TOU-2 kW	79	-$844	-$1,029	-$1,002	-$946	-$852	-$746	-$680	-$589	0
Flat-0 kW	TOU-0 kW	79	-$153	-$493	-$317	-$235	-$164	-$56	-$19	$108	5
Flat-2 kW	TOU-2 kW	79	-$173	-$512	-$336	-$256	-$184	-$74	-$39	$89	3
Flat-0 kW	TOU-2 kW	79	-$998	-$1,464	-$1,293	-$1,147	-$951	-$849	-$742	-$669	0
SCE	*BILL LEVELS*										
	Solar PV	Number of					PERCENTILES				
Tariff	size (DC)	Customers	Mean Bill		10th	25th	50th	75th	90th		
Flat	0 kW	61	$3,151		$1,817	$2,229	$2,663	$3,561	$4,690		
TOU-min	0 kW	61	$2,860		$2,022	$2,216	$2,645	$3,085	$3,687		
TOU-avg	0 kW	61	$2,931		$2,044	$2,255	$2,683	$3,176	$3,745		
Flat	2 kW	61	$2,381		$1,147	$1,472	$1,891	$2,713	$3,827		
TOU-min	2 kW	61	$2,273		$1,389	$1,632	$2,049	$2,520	$3,122		
TOU-avg	2 kW	61	$2,319		$1,434	$1,641	$2,082	$2,562	$3,132		
SCE	*BILL CHANGES*										
From	To		Mean Change	Min	10th	25th	50th	75th	90th	Max	# > 0
Flat-0 kW	Flat-2 kW	61	-$770	-$862	-$857	-$821	-$786	-$745	-$667	-$546	0
TOUmin-0 kW	TOUmin-2 kW	61	-$587	-$662	-$640	-$610	-$565	-$565	-$565	-$560	0
TOUavg-0 kW	TOUavg-2 kW	61	-$612	-$614	-$614	-$614	-$614	-$614	-$607	-$588	0
Flat-0 kW	TOUmin-0 kW	61	-$291	-$2,580	-$984	-$630	-$145	$90	$290	$636	21
Flat-0 kW	TOUavg-0 kW	61	-$220	-$2,190	-$855	-$564	-$129	$139	$296	$652	22
Flat-2 kW	TOUmin-2 kW	61	-$108	-$2,322	-$687	-$379	$4	$199	$335	$581	31
Flat-2 kW	TOUavg-2 kW	61	-$62	-$1,980	-$606	-$339	$36	$207	$359	$637	33
Flat-0 kW	TOUmin-2 kW	61	-$878	-$3,145	-$1,550	-$1,195	-$758	-$520	-$340	-$10	0
Flat-0 kW	TOUavg-2 kW	61	-$832	-$2,804	-$1,469	-$1,178	-$742	-$475	-$313	$46	1

Table 1B: Bill Levels and Changes Under Alternate Tariffs and Solar PV Installations
(includes all single-family households in SPP flat-rate tariff control group with annual consumption above 6000 kWh)

PG&E	*BILL LEVELS*										
	Solar PV	Number of					PERCENTILES				
Tariff	size (DC)	Customers	Mean Bill		10th	25th	50th	75th	90th		
Flat	0 kW	100	$2,087		$1,044	$1,288	$1,731	$2,468	$3,798		
TOU	0 kW	100	$1,974		$973	$1,199	$1,613	$2,293	$3,630		
Flat	2 kW	100	$1,396		$528	$725	$1,052	$1,661	$2,884		
TOU	2 kW	100	$1,262		$403	$590	$884	$1,457	$2,714		
PG&E	*BILL CHANGES*										
From	To		Mean Change	Min	10th	25th	50th	75th	90th	Max	# > 0
Flat-0 kW	Flat-2 kW	100	-$692	-$1,002	-$938	-$834	-$681	-$560	-$459	-$344	0
TOU-0 kW	TOU-2 kW	100	-$711	-$1,021	-$958	-$854	-$703	-$578	-$477	-$363	0
Flat-0 kW	TOU-0 kW	100	-$114	-$493	-$225	-$170	-$102	-$50	-$5	$83	8
Flat-2 kW	TOU-2 kW	100	-$133	-$512	-$242	-$189	-$124	-$69	-$25	$64	4
Flat-0 kW	TOU-2 kW	100	-$825	-$1,464	-$1,142	-$946	-$818	-$680	-$537	-$405	0
SCE	*BILL LEVELS*										
	Solar PV	Number of					PERCENTILES				
Tariff	size (DC)	Customers	Mean Bill		10th	25th	50th	75th	90th		
Flat	0 kW	69	$2,283		$1,100	$1,381	$1,841	$2,663	$3,678		
TOU-min	0 kW	69	$2,250		$1,423	$1,587	$2,044	$2,665	$3,106		
TOU-avg	0 kW	69	$2,298		$1,453	$1,618	$2,048	$2,712	$3,198		
Flat	2 kW	69	$1,602		$594	$765	$1,161	$1,901	$2,877		
TOU-min	2 kW	69	$1,639		$788	$944	$1,389	$2,080	$2,541		
TOU-avg	2 kW	69	$1,691		$852	$1,005	$1,446	$2,102	$2,584		
SCE	*BILL CHANGES*										
From	To		Mean Change	Min	10th	25th	50th	75th	90th	Max	# > 0
Flat-0 kW	Flat-2 kW	69	-$682	-$862	-$831	-$787	-$676	-$587	-$515	-$388	0
TOUmin-0 kW	TOUmin-2 kW	69	-$611	-$662	-$658	-$646	-$614	-$565	-$565	-$565	0
TOUavg-0 kW	TOUavg-2 kW	69	-$607	-$614	-$614	-$614	-$614	-$604	-$590	-$557	0
Flat-0 kW	TOUmin-0 kW	69	-$34	-$2,580	-$676	-$145	$126	$275	$342	$636	44
Flat-0 kW	TOUavg-0 kW	69	$15	-$2,190	-$567	-$129	$156	$300	$375	$652	45
Flat-2 kW	TOUmin-2 kW	69	$37	-$2,322	-$415	$4	$132	$239	$313	$581	52
Flat-2 kW	TOUavg-2 kW	69	$89	-$1,980	-$361	$36	$175	$303	$349	$637	53
Flat-0 kW	TOUmin-2 kW	69	-$644	-$3,145	-$1,241	-$758	-$496	-$359	-$269	-$10	0
Flat-0 kW	TOUavg-2 kW	69	-$593	-$2,804	-$1,181	-$742	-$457	-$309	-$223	$46	1

TABLE 2: Representative Calculations of Levelized Real Cost Per kWh for 2 kW (DC) System
(cost calculator spreadsheet available from author)

Avg AC kWh/hr (new)	Annual decline in output	Installation Cost	Current Inverter Cost	Annual Real Inveter Cost Decline	Real Interest Rate	Levelized Cost per kWh
0.324	1%	$10,500	$1,600	2%	-2%	$0.171
0.324	1%	$10,500	$1,600	2%	0%	$0.208
0.324	1%	$10,500	$1,600	2%	3%	$0.274
0.324	1%	$10,500	$1,600	2%	5%	$0.322
0.324	1%	$10,500	$1,600	2%	7%	$0.374

Table 3: Savings per kWh of Power Produced by Solar PV
(includes all customers in SPP control groups)

PG&E		Number of	Mean			PERCENTILES				
From	To	Customers	Savings/kWh	Min	10th	25th	50th	75th	90th	Max
Flat-0 kW	Flat-2 kW	163	$0.252	$0.124	$0.165	$0.206	$0.248	$0.305	$0.335	$0.363
TOU-0 kW	TOU-2 kW	163	$0.259	$0.130	$0.172	$0.214	$0.254	$0.311	$0.344	$0.370
Flat-0 kW	TOU-2 kW	163	$0.304	$0.146	$0.193	$0.244	$0.299	$0.364	$0.412	$0.526
Flat-0 kW	BEST-2kW	163	$0.304	$0.146	$0.193	$0.244	$0.299	$0.364	$0.419	$0.526
SCE		Number of	Mean			PERCENTILES				
From	To	Customers	Savings/kWh	Min	10th	25th	50th	75th	90th	Max
Flat-0 kW	Flat-2 kW	111	$0.234	$0.134	$0.179	$0.202	$0.235	$0.275	$0.292	$0.299
TOU-0 kW	TOU-2 kW	111	$0.211	$0.195	$0.196	$0.196	$0.213	$0.223	$0.228	$0.229
Flat-0 kW	TOU-2 kW	111	$0.229	$0.003	$0.099	$0.123	$0.178	$0.287	$0.466	$1.089
BEST-0kW	BEST-2kW	111	$0.208	$0.134	$0.179	$0.196	$0.202	$0.231	$0.247	$0.264