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SolaROI:

Estimating Returns to Residential Solar Panels from Underlying Tariff Structures and Compensation Mechanisms

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Introduction

This report explores how the return on investment for solar panel installations at the household level can be fundamentally affected by the underlying tariff structures for residential electricity consumption and compensation mechanisms for renewable distributed electricity generation. Distributed generation (DG) technologies such as rooftop solar photovoltaics (PV) have the ability to help reduce the amount of greenhouse gases (GHGs) produced from conventional, centralized, fossil-based electricity generation while also benefitting the solar panel owner through lower electricity bills. While solar DG in addition also can provide health benefits and contribute to job growth, it raises some challenges for the current utility business model and regulators. As greater numbers of electricity consumers adopt solar panels and generate their own electricity onsite, public utilities perceive the advancing DG deployment as a threat to their financial health. Thus, state regulators are beginning to reassess the very policies that were put in place to jumpstart nascent markets for DG systems. As a result, rate designs, feed-in tariffs, and policies such as net energy metering are being revisited or repealed across the country in an effort to better reflect the costs and benefits for all industry stakeholders –load serving entities, electric distribution companies, PV owners, and non-solar customers. As the debate around the true value of DG and the future of utility business models unfolds, it is crucial to not only recognize the range of costs and benefits of DG, both social and private, but also – and more pertinent to this paper – to fully understand how tariff structures and DG-related policies and incentives directly affect investment potential for distributed PV, the fastest-growing distributed energy resource.

The magnitude of the challenge presented by the advancing penetration of solar DG has become evident with the recent boom in rooftop PV investment across the country, especially in the state of California. Several factors have contributed to this boom. Among them are a steep decline in capital costs of solar PV, availability of creative financing options, as well as federal, state, and local policies and incentives designed to promote solar PV and other distributed energy sources – such as the 30% Residential Renewable Energy Federal Tax Credit and most notably the widely available credit arrangement referred to as Net Energy Metering (NEM). Figure 1 shows the past growth in NEM capacity in California, which ranks first in the country in installed solar capacity. Figure 2 shows the share of installed NEM capacity in coincident aggregate demand and illustrates that NEM is covering an increasing share of system peak demand – in California close to 5% in both Pacific Gas & Electric's (PG&E) and San Diego Gas & Electric's (SDG&E) service territories in 2013.

[1] Energy and Environmental Economics, Inc. (E3), California Net Energy Metering Ratepayer Impacts Evaluation, CPUC, Oct 28, 2013, p. 27

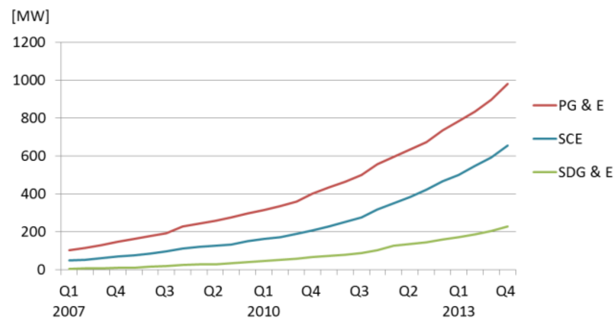

FIGURE 1: Cumulative NEM Capacity in California investor-owned utility service territories.
Source: CSI 2013 Progress report. California Public Utilities Commission.

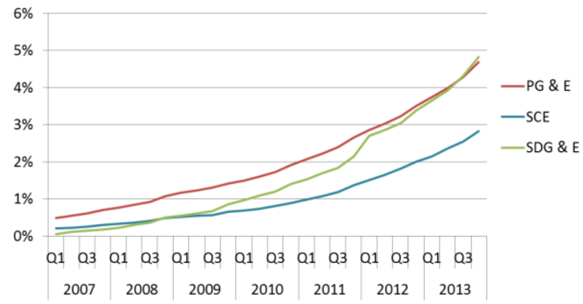

FIGURE 2: NEM Capacity as % of Coincident Aggregate Customer Demand.
Source: CSI 2013 Progress report. California Public Utilities Commission.

Since 2010 alone, net-metered solar PV capacity has grown at an annual rate of about 1,100 MW. Though NEM policies vary across the country, NEM generally allows the utility customer to receive credit at retail value for any electricity that she exports to the grid from the on-site solar PV system. This allows the customer's meter to, in effect, spin backwards and offset the electricity costs for the year by building up credit on a month-by-month basis with the utility. Most of the NEM rules further require the host utility company to compensate customers for any electricity generated in excess of onsite load over a 12-month period. This compensation for excess generation is generally about 3-4 cents per kWh, which is much lower than the retail rate[2].

Given how critical NEM has been to the growth of solar PV development it may not be surprising that this policy has been at the forefront of a growing and contentious debate pitting utilities against solar advocates across the country. This tension is particularly palpable in California, where the state's three investor-owned utilities (IOUs) are challenging the current NEM structure. But even in states where solar penetration is relatively minimal, such as Oklahoma and South Carolina, some utilities are pushing back against the policy. At large, NEM critics argue that owners of solar PV systems that remain connected to the grid do not pay for all the electric services they use. Grid integration provides solar PV customers with constant, reliable grid support despite their reduced use and payments for grid electricity, thereby burdening non-solar customers with an unfair share of grid-costs through higher rates.[3] This is particularly true for those customers who offset almost all of their consumption with solar generation. Because their yearly bill approaches zero, these customers do not contribute fully to the utility's transmission and distribution costs which generally are recovered through variable rates charged on electricity consumption. The failure of volumetric charges to fully recover the utility's costs in the context of NEM has caused utilities to consider higher fixed monthly bill

[2] The level of this payment is based on the utility's avoided cost and approximately corresponds to the wholesale price of electricity.
[3] Decreased demand caused by the integration of distributed energy resources (in a rate of return regulatory environment) leads to declining revenues for the utility, which in turn requires utilities to raise rates so they can recoup fixed costs. The so-called utility death spiral unfolds further as increasing rates drive more customers away from the system.

charges that cannot be avoided by NEM customers. A higher fixed charge would decrease the incentive to both conserve as well as install solar panels, and has therefore faced resistance. Solar advocates on the other hand demand that utilities pay DG owners for avoided transmission and generation costs, especially at peak times, and for the value that solar panels provide to all ratepayers.

Regulators have responded with various proceedings in response to the debate. In 2012 California enacted Assembly Bill 2514 (AB 2514), which directed the California Public Utilities Commission (CPUC) to undertake a study that examines the benefits and costs of NEM to all ratepayers. Moreover, as per California's Assembly Bill 327, the CPUC is currently in the process of determining new NEM rules to take effect in 2017. Meanwhile, in the neighboring and also strong solar state of Arizona, the Arizona Corporation Commission (ACC) in November 2013 authorized the state utility Arizona Public Service (APS) to impose an unprecedented grid-connection fee consisting of $0.70 per kW for solar NEM customers.[4] The state of Oklahoma, which ranked 37th with 300 kW of cumulative installed solar PV capacity in 2012[5], followed suit this April by creating a new customer class for grid-connected solar DG customers that will include a yet to be determined monthly surcharge. Finally, Minnesota's Public Utilities Commission recently approved the nation's first state-wide formula for calculating the value of customer-generated solar power - a framework first pioneered by the Texan utility Austin Energy - which will essentially replace NEM by introducing a separate price on PV generated electricity and fundamentally change the relationship between utilities and self-generating customers.[6]

Net Energy Metering & Underlying Tariff Structures

While NEM is the focal point of the debate on how to value rooftop solar, any discussion of NEM is inherently linked to the underlying rate design structures, as these directly impact the economics of NEM and consequently those of the PV system. Rate structures can encourage and discourage consumption, affect usage patterns, such as the time of energy consumption, and they also have the ability to influence the above mentioned shift of grid-related costs from NEM customers to non-NEM utility ratepayers. In this regard it is important to point out that California's Public Utilities Commission is not only investigating the future of NEM in the state but is also set to approve new residential rate designs by 2015 which will have significant impacts on solar investments in the state. Under consideration are fixed customer charges, reduction of the number of residential rate tiers, and time-of-use rates as an alternative to inclining block rates. Other policies considered that could have a significant impact on NEM customers and the economics of customer-sited solar PV are rules pertaining to customer sited storage, electric vehicles, and compensation for demand-response services.

The rates currently faced by the large majority of ratepayers in California are inclining block rates (IBR) whereby each increasing tranche of electricity consumption faces a higher marginal

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[4] Utility Drive (11.18.2013): Who won the Arizona solar showdown?
[5] U.S Solar Market Trends 2012. Interstate Renewable Council (2013).
[6] Utility Dive (4.1.2014). Can Minnesota's Value of Solar end the net metering debate?

rate. Prices increase steeply over two, three, or four tiers of rates as usage increases. While this could theoretically disincentivize higher usage of electricity overall[7], NEM when combined with IBR effectively encourages usage as it allows high-usage customers to avoid higher tiers with correspondingly higher rates.[8] As such, the NEM-IBR combination presents a strong incentive for large electricity consumers to invest in solar panels. However, because the NEM-IBR pairing does not create an incentive to shift the time of consumption – for instance from a high peak time, when electricity is the most expensive on the grid, to a time window when the grid is confronted with less electricity demand and congestion – it does not realize the vast array of benefits associated with solar DG, such as peak demand reduction and lower system costs.[9]

By contrast, more refined tariff structures have the ability to send price signals that can alter the time of electricity consumption in a way that provides benefits to the grid at large. Time varying rates under NEM, for instance, benefit the solar panel owner the most when self-generation occurs during high-cost peak periods. However, as installed solar PV capacity increases over time, the traditional peak demand in the middle of the day could shift towards later in the evening, when solar generation ramps down and NEM customers resume pulling electricity from the grid. When the peak window shifts to later in the day, the majority of the solar generation (which occurs during mid-day when the sun is high) will no longer occur during high priced times. This means that the NEM customer is no longer able to net PV generation off high-priced mid-day electricity consumption; hence, the benefits of the solar PV investment to the homeowner decrease. This example illustrates the range of potential effects that different rate design structures (such as the relative peak and off-peak prices faced by the consumer or the timing of the peak window) can have on solar DG investment decisions.

As California and other states across the U.S. embark on substantial changes to NEM and rate design structures, utilities, ratepayers, and solar developers alike will be confronted with many unknowns. Thus, it is both timely and crucial to analyze how these impending changes can impact investment in solar DG and consequently the long-term viability of residential solar.

Purpose and Results Overview

In this paper, we explore the value proposition of solar PV from the perspective of the residential customer by answering the following question: what is the residential customer's return on investment from installing a rooftop PV given alternative tariff structures and solar compensation mechanisms?

We calculate returns on investment (ROI) to homeowners with a solar PV system given four different tariff structures. Specifically, we look at returns under the current four-tiered inclining block rates and compare them to returns under two new rate structures proposed by PG&E in

[7] Although they may retain a conservation signal, IBR are problematic in the sense that they go against cost-causation: serving 1MW to a customer is much cheaper to the utility than serving 1kW to 1000 different customers. Therefore, the problems associated with NEM are enhanced by the problematic underlying IBR.
[8] R. Thomas Beach and P. McGuire. Evaluating the Benefits and Costs of Net Energy Metering in California. Crossborder Energy. January 2013.
[9] http://www.edf.org/sites/default/files/R.12-06-013%20Residential%20Rate%20Proposal%20of%20EDF.pdf

the ongoing rate proceedings: a new two-tiered inclining block rate and a voluntary time of use rate. We additionally analyze time-of-use rates with an evening instead of a mid-day peak window to reflect the effect that zero-marginal cost renewable generation – both solar PV and utility-scale solar and wind – is having on grid economics. Furthermore, we estimate the price on PV generated electricity (similar to Austin Energy's Value of Solar tariff) that would cause the customer to break even on their PV investment. Essentially, this break-even Value of Solar (VOS) indicates the minimum feed-in tariff that would be required to still stimulate further investment in residential solar PVs if a VOS tariff were to replace NEM as the compensation mechanism for residential solar electricity generation.

We look at investments in PV systems of the size that covers all of the household's cumulative yearly electricity use. We find that for high load customers (i.e., those with monthly consumption levels 50%-100% higher than the average), returns are lower with the new two-tiered tariff structure compared to the current four-tiered tariff structure, due to the fact that they no longer are able to net off of the highest tier prices. The opposite holds for average load customers – as their consumption is concentrated in the bottom tiers, the flatter rate structure proposed by PG&E increases their average retail rate, thereby providing higher payback from NEM. This result for the average load customers is however sensitive to the choice of starting values for two-tiered rates.

For PG&E's proposed time-of-use (TOU) rates, we find that returns are lower than under the current four-tiered tariff structure. However, high load customers that are initially on the two-tiered tariff structure can incur additional savings from switching to time of use rates, making the total savings from both the rate change and PV investment larger. We also find that TOU rates with an evening peak window still provide a positive net present value under a conservative set of assumptions.

We further find that a value of solar tariff utilized as a compensation mechanism would have to be 22 cents - much larger than the 13 cents currently offered by Austin Energy - to provide a positive NPV for a solar panel investor in PG&E's service territory. Finally, we find that as long as fixed charges levied on PV owners are less than 10 dollars per month under the proposed future two-tiered inclining block rates, returns to PV investment remain positive for average and above average electricity users in almost all of PG&E's service territory.

Methods and Data

We have developed an Excel model (SolaROI) that estimates the return on PV investment (expressed in terms of net present value, payback period and internal rate of return) for PG&E's residential customers. The model calculates returns on investment (ROI) to homeowners with a solar PV system given a variety of tariff structures (4 tier IBR, 2 tier IBR, TOU rates with midday peaks, and TOU rates with evening peaks) against a variety of compensation mechanisms (NEM, different levels of excess generation payments, and feed-in tariffs). The model further allows for consideration of other issues that may affect the ROI such as grid-connection fees specific to PV owners. SolaROI is flexible and can be used by utility staff or policy makers to identify the impact of different proposed pricing mechanisms. A detailed description of all the data, model and methods can be found in the Appendix. Here, we provide a brief summary.

Model Overview

SolaROI estimates net present value, payback period and internal rate of return as measures of ROI. We utilize aggregate data in the PG&E service territory on residential hourly and monthly load across different regions and PVWatts generation data to create monthly load and solar PV generation for ten representative consumers across PG&E's territory. These consumers correspond to each of PG&E's climate zones, as shown in Figure 3. Each climate zone faces a different pricing structure, different levels of demand and different solar generation potentials.

FIGURE 3: Climate Zone Map for PG&E

SolaROI first calculates the estimated bill per household based on observed average demand throughout the year and the day. The tool next calculates how the bill changes when generation is considered. We gather and extrapolate data on solar generation for a 1 kW system from the National Renewable Energy Laboratory's (NREL) PVWatts calculator in regions that represent each climate zone – for example, we use San Francisco generation as representative of climate zone T and Fresno as representative of climate zone R. The PVWatts data are separated out for each hour within an entire year, allowing us to model how much of the solar electricity in each month is generated during the proposed peak and off-peak hours.

Figure 4 shows how the average household's annual demand and solar PV generation capabilities vary across climate zones. This figure shows that for an average load home in

Fresno, a 1 kW PV system will provide only 17% of household load, while an average load home in San Francisco will satisfy 31% of household load with a 1 kW system. Generally, when investing in rooftop PV, the household chooses how much of the existing load is to be covered with a rooftop solar panel- the percentage of the maximum load covered by onsite generation ranges between 25% and 100% of average yearly load. Existing regulations limit the size of the PV system that a household can install and requires that the panel does not generate more than the household's historic average yearly load. For a representative home choosing to cover 100% of average yearly load, our model calculates the required PV system size for a Fresno home to be 6.0 kW, but only 3.2 kW in San Francisco. Figure 4 illustrates how the system size required to fully offset household load changes by zone.

Once the maximum share of the household's onsite load to be covered by the PV system has been chosen, the model calculates the required system size and scales up the generation data as provided by NREL's PVWatts tool to calculate how much electricity is generated throughout the month and across the hours of the day for the relevant PV system size.

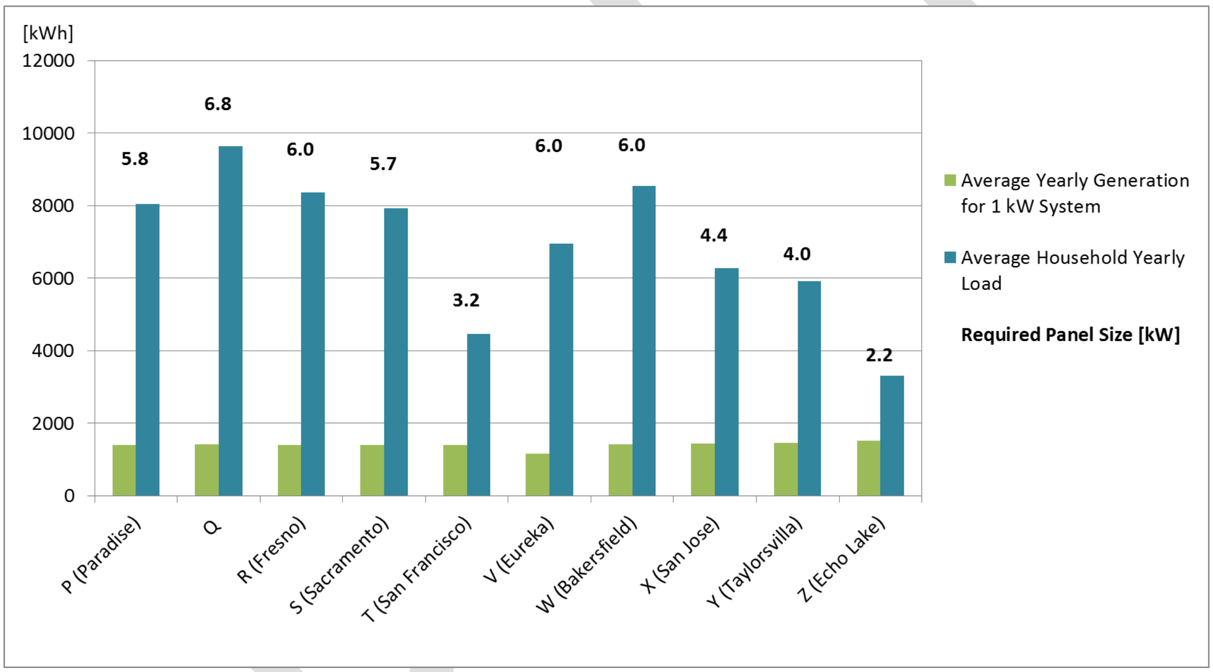

FIGURE 4: Average household loads, generation per installed kW and the PV system size required to cover 100% of household load by climate zone

Given the system size, SolaROI utilizes data on solar PV costs to calculate the monthly payments (either upfront or through a loan) that the household would incur to purchase this PV system. It further measures the savings from the PV system by calculating the monthly electricity bill with and without the PV system for the lifetime of the solar panel. Based on these costs and bill savings, the returns to investment in terms of net present values, internal rate of return and payback period are calculated.

Electricity Bill calculations
We assume that the data on electricity consumption (both total consumption and load shape across the hours) reflect the underlying tariff structures at the time of data collection- thus, areas with higher rates would likely have lower consumption amounts given normal elasticities of demand. Because our consumption data are aggregated at the climate zone level, it allows us to identify the underlying IBR rate across the different climate zones. Of course, households with TOU rates would likely also have different consumption patterns, particularly throughout the day. However, given the very low penetration of voluntary TOU adoption, we assume that average consumption is not affected by this low rate of adoption. Hence, we assume that the load curves across climate zones correspond to the IBR rate in place during the time when the data were collected (2011-2012). Because the tier levels differ across zones, the IBRs are effectively different for the 10 representative consumers in each climate zone.

When the tariff changes for a NEM customer, it has two distinct effects. First, customers may change the timing and magnitude of their demand in response to the new prices- if the average price increases, consumption will decrease given normal elasticities of demand. Second, the value of the generated electricity netted off the bill will also change given the new tier prices. Therefore, we first calculate how load will change when a household moves to a different tariff structure (using the 2011-2012 4 tier IBRs as the baseline scenario), and then calculate the financial implications in terms of electricity bills with and without a PV system.

Research suggests that under IBRs the customer responds to average rather than marginal prices.[10] With a shift to another set of IBRs, the average price would change and we would therefore, according to economic theory, also expect electricity consumption to change. If the average rate the consumer faces under the new IBR is higher than the average rate she faced in 2011-2012, the consumer will respond by decreasing her electricity consumption, and vice versa.

When a household changes its tariff from IBR to TOU, economic theory and a large body of experience with utility studies indicate two distinct changes in electricity demand. The first is a shift from peak to off-peak times of day; as peak time electricity becomes relatively more expensive, the household will consume less peak energy and more off-peak energy (although displacement need not be 100%, resulting in some conservation overall). The second change in behavior is due to the overall change in prices, just as with the shift to another set of IBRs. If the average rate the consumer faces under TOU is lower than the average rate faced under IBRs, the consumer will respond by increasing consumption overall under TOU, and vice versa.

We calculate these load changes using price elasticities[11] estimated from the 2004 California Statewide Pricing Pilot[12]. These elasticities allow us to generate a baseline demand for an average household without a PV system given the change in prices from a tariff structure

[10] Ito, K. (2014). Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing. *American Economic Review*,104(2), 537-563.
[11] The price elasticity of demand is defined as the percentage change in demand from a percentage change in the price.
[12] https://www.smartgrid.gov/sites/default/files/doc/files/Impact_Evaluation_California_Statewide_Pricing_Pilot_200501.pdf

change, or from an exogenous change in prices over time. We allow the SolaROI user to specify the size of the elasticities (zero, low, medium, or high) based on these estimated values. Given the shift in electricity demand from the new tariff structure, we calculate the monthly bill for a household without a PV system.

Our next step is to calculate the monthly bill statement after the solar panel is installed. We estimate the bill under two different compensation mechanisms: NEM and a value of solar feed-in tariff.

For NEM compensation, the household subtracts generation from consumption at the monthly level, and in essence receives a retail rate on the generation within the month. This means that the household will receive a credit for generation exceeding consumption within the month, and a debit when generation is less than consumption within the month. Following the description of PG&E's NEM program, we apply a yearly, rather than a monthly, true-up which sums all monthly credits and debits at the end of the year. The household will then receive a positive or negative year-end bill. If the year-end bill is negative, the household will not pay anything for electricity in that year (other than the fixed charges which cannot be netted against). In this case, if, additionally, the household's yearly total electricity generation is greater than its yearly total electricity consumption, then the utility will pay the homeowner the avoided generation rate for each kWh generated in excess of consumption.

In the NEM and IBR scenario, the statement is calculated by first netting generation from consumption, then the debit or credit is calculated given the net electricity consumption. This results in a reduction of the highest tier payments first. Under the NEM and TOU scenario, peak generation is subtracted from peak consumption, and off-peak generation is subtracted from off-peak consumption, then the remainders are multiplied by their relative prices. The formulas below show how the true-up works, first for NEM and IBR and then for NEM and TOU rates, where AGC refers the avoided generation cost (3-4 cents/kWh) and FC refers to all fixed charges summed at the yearly level (including those levied on all consumers and those specific to PV owners).

<u>Yearly True-up with NEM and IBR</u>

$$Monthly\ Statement_i = (Consumption_i - Generation_i) * avg\_price_i \qquad i = 1,\ldots,12$$

$$Yearly\ Bill = \begin{cases} \sum_{i=1}^{12} Monthly\ Statement_i & if \quad \sum_{i=1}^{12} Monthly\ Statement_i > 0 \\ -\left[\sum_{i=1}^{12} (Generation_i - Consumption_i)\right] * AGC & if \quad \sum_{i=1}^{12} Monthly\ Statement_i < 0 \end{cases}$$

Yearly True-up with NEM and TOU:

$$Monthly\ Statement_i = \left(Consumption_{peak,i} - Generation_{peak,i}\right) * price_{peak,i} + \left(Consumption_{off-peak,i} - Generation_{off-peak,i}\right) * price_{off-peak,i} \qquad i = 1,\ldots,12$$

$$Yearly\ Bill = \begin{cases} \sum_{i=1}^{12} Monthly\ Statement_i & \text{if} \quad \sum_{i=1}^{12} Monthly\ Statement_i > 0 \\ -\left[\sum_{i=1}^{12}\left(Generation_i - Consumption_i\right)\right] * AGC & \text{if} \quad \sum_{i=1}^{12} Monthly\ Statement_i < 0 \end{cases}$$

With both rate structures, in the case of a negative year-end bill, any excess generation is rewarded at the same rate regardless of when the electricity was generated, even though peak generation is more valuable to the utility than off-peak generation.

For the feed-in-tariff, the household pays the full bill and then receives a check or credit for the value of total generation.

Analyzed Tariff Structures

In the current rate proceedings under California's Public Utilities Commission (with proceeding number R1206013), PG&E has filed a rate proposal for inclining block rates that entails a gradual shift over the period 2015-2018 from four to two tiers and a move towards a smaller difference between the top and bottom tier rates. PG&E is also proposing simplified voluntary time-of-use rates that are not overlaid with a tiered structure, as is the case with PG&E's current voluntary TOU rates. Another essential feature of the proposal is a monthly surcharge for all customers starting at $5 in 2015 and increasing to $10.42 in 2018.

Table 1 presents the rates proposed by PG&E for 2018 when the two tier structure has been phased in and compares them to the rates in place during the period 2011-2012 – the period during which the baseline load data was generated. Table 2 presents the TOU rates proposed by PG&E for 2015.

TABLE 1. PG&E's Inclining Block Rate. The first set of rates are the average rates for the period 2011-2012 which corresponds to the electricity consumption baseline data. The second set is the two-tiered rates proposed by PG&E for the year 2018.

	Tier 1	Tier 2	Tier 3	Tier 4
Price [$/kWh], average 2011-2012	0.126	0.144	0.299	0.339
Price [$/kWh], rate proposal for 2018	0.177	0.212	0.212	0.212
Summer Upper limit [kWh/month]				
Climate zone R (incl. Fresno)	523	680	1047	
Climate zone T (incl. San Francisco)	230	298	459	
Winter Upper limit [kWh/month]				
Climate zone R (incl. Fresno)	356	463	712	
Climate zone T (incl. San Francisco)	277	360	554	

TABLE 2. Time-of-use rates proposed by PG&E for 2015.

	Peak	Off-peak	Peak Window
Summer price [$/kWh]	0.319	0.182	1pm-7pm
Winter price [$/kWh]	0.183	0.169	5pm-8pm

In this report, we compare ROI under four different tariff structures:

- Inclining block rates with four tiers and first year rates as in 2011-2012 (henceforth four-tiered IBRs)
- Inclining block rates with two tiers and first year rates as in the PG&E proposal for 2018 (henceforth two-tiered IBRs)
- Time-of-use rates that correspond to PG&E's proposal for simplified time-of-use rates in 2015 with a peak window between 1 and 7 pm in the summer and 5 and 8 pm in the winter (henceforth TOU rates with mid-day peak)
- Time-of-use rates that correspond to PG&E's proposal for simplified time-of-use rates in 2015 but with a peak window between 5 and 8 pm in both summer and winter (henceforth TOU rates with evening peak)

We use the nominal values for the proposed two-tiered and TOU rates for the first year after investment. After the first year, all rates increase proportionally and nominally by 3% per year.

We calculate returns for all ten climate zones in PG&E's service territory. Because returns differ depending on the household load we also calculate returns for three levels of load - average load (as defined by the average consumption for each household across each climate zone), 150% of average load and 200% of average load in each zone. We assume that the household installs a PV system that covers at most their yearly load and looks at the case with zero loan financing.

Findings

To illustrate the results, we focus mainly in this section on the ROI for high usage customers[13] (150% of average load) in two of the climate zone areas: R, the zone that includes Fresno and surrounding areas, and T, the climate zone that includes San Francisco and other coastal areas. The zones are shown in Figure 3. Results are presented in 2012 dollars.

Determinants of Bill Savings under Net Energy Metering

Tier Structure

With inclining block rates, the bill savings from PV investment are determined by how consumption and PV generation are distributed across the months. On the left, Figure 5 illustrates monthly household load and PV generated electricity for the winter and summer months across the two selected climate zones (Fresno and San Francisco areas) in 2011-2012. The bars show the tier allocations with the four-tiered IBRs and illustrate that a large share of these customers' electricity usage is charged the top tier rate. The high load customer in Fresno is on average consuming 200 kWh per month above the third tier quantity and therefore paying the maximum rate for this load without a PV system installed. In comparison, in San Francisco, the high load customer is only paying the maximum rate for 60 kWh per month. By netting off the top tier, a high load customer in Fresno should therefore have higher bill savings to make from investing in a PV system under the current tariff structure.

On the right, Figure 5 shows instead the tier allocation for the proposed two-tier IBRs. In this graph, we have adjusted electricity consumption given the change in the average rate that this new tariff structure implies, using the approach outlined in the Methods section (i.e., lower average rates lead to higher consumption levels). Although more consumption is going into the top second tier with the collapse of four tiers into two, bill savings from investment in a PV system should be lower for the high load household under this new tariff structure because the top tier rate is lower than the current third and fourth tier rates.

We also assume that the household load is affected by generation in the IBR setting. Because netting generation off of consumption results in a decreased quantity of kWh in the top tiers, this effectively reduces the household's average rate. Given the household's elasticity of demand (as specified by SolaROI's user), we subsequently increase consumption to reflect the lower average rate.

[13] We choose to focus mainly on high load customers because these are the households most likely to make the investment. However, we also look at average households; see Figure 8.

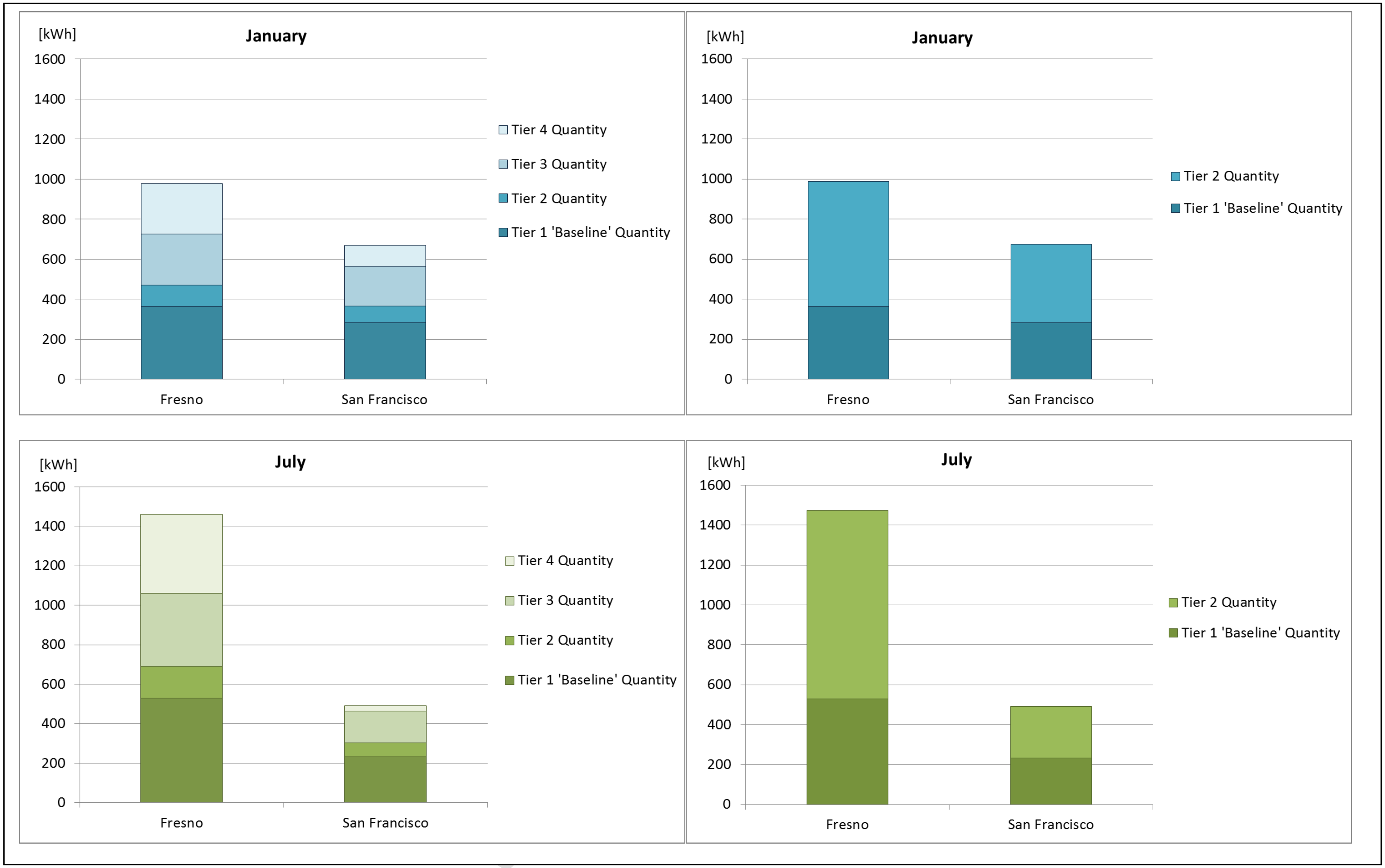

FIGURE 5: Winter (January) and summer (July) load for a high load household in Fresno and San Francisco, respectively, in relation to the four-tier and proposed two-tier allocation in each climate zone.

Load Shape

Under TOU rates, bill savings from PV investments depend greatly on how PV generation is distributed across the months and throughout the day. Figure 6 shows how both load and generation are distributed across the day for an average January and an average July day for zone R (Fresno) and zone T (San Francisco), respectively. The value of the electricity generated by the PV system depends on how it aligns in time with the peak and off-peak rates.

Since, under NEM, the excess electricity that the household produces is credited at the TOU rate that corresponds to the time at which it is generated, the value of the generated electricity is the same no matter if it is consumed by the household or exported to the grid. We therefore assume that there is no change in the household load from investment in the PV system under TOU rates since the marginal prices of electricity throughout the day are not affected by how much electricity that is generated by the PV system.[14,15] Therefore, because the peak PV generating capacity is during mid-day, the savings from PV investment should be larger under TOU rates with a mid-day peak window than under the same TOU rates with an evening peak window.

In addition, households that originally were on IBR may incur further savings from switching to TOU rates that are additional to the savings from the PV investment. Whether there are additional savings depends on how the average rate per kWh is affected by the change in tariff structures. For a high load household that has a higher share of its electricity consumption in the top tiers and therefore faces a higher average electricity rate, savings from switching to the proposed TOU rates are larger than for an average load household. The savings from switching to TOU rates from IBRs are the same irrespective of whether the household on TOU rates has a PV system installed or not because, as previously discussed, under TOU rates there is no change in the household load from investment in a PV system.

[14] This is different than for households under IBR. PV generation can change the marginal price the household faces for consumption (by moving the household into a different tier) and also changes the average price for all consumption. Given Ito (2014)'s findings that IBR lead to average rather than marginal price responses, we assume the household under IBRs adjusts consumption based on changes in average rates. In contrast, Ito (2014) finds that TOU rates lead to marginal price responses rather than average price responses (see footnote 7 for Ito (2014)).

[15] Note that this is an assumption consistent with economic theory for optimizing behavior but that in practice it may be that households respond differently. If they do not correctly value the excess electricity at the market rate, it is possible that their consumption around the time of peak generation would increase after an investment in a PV system.

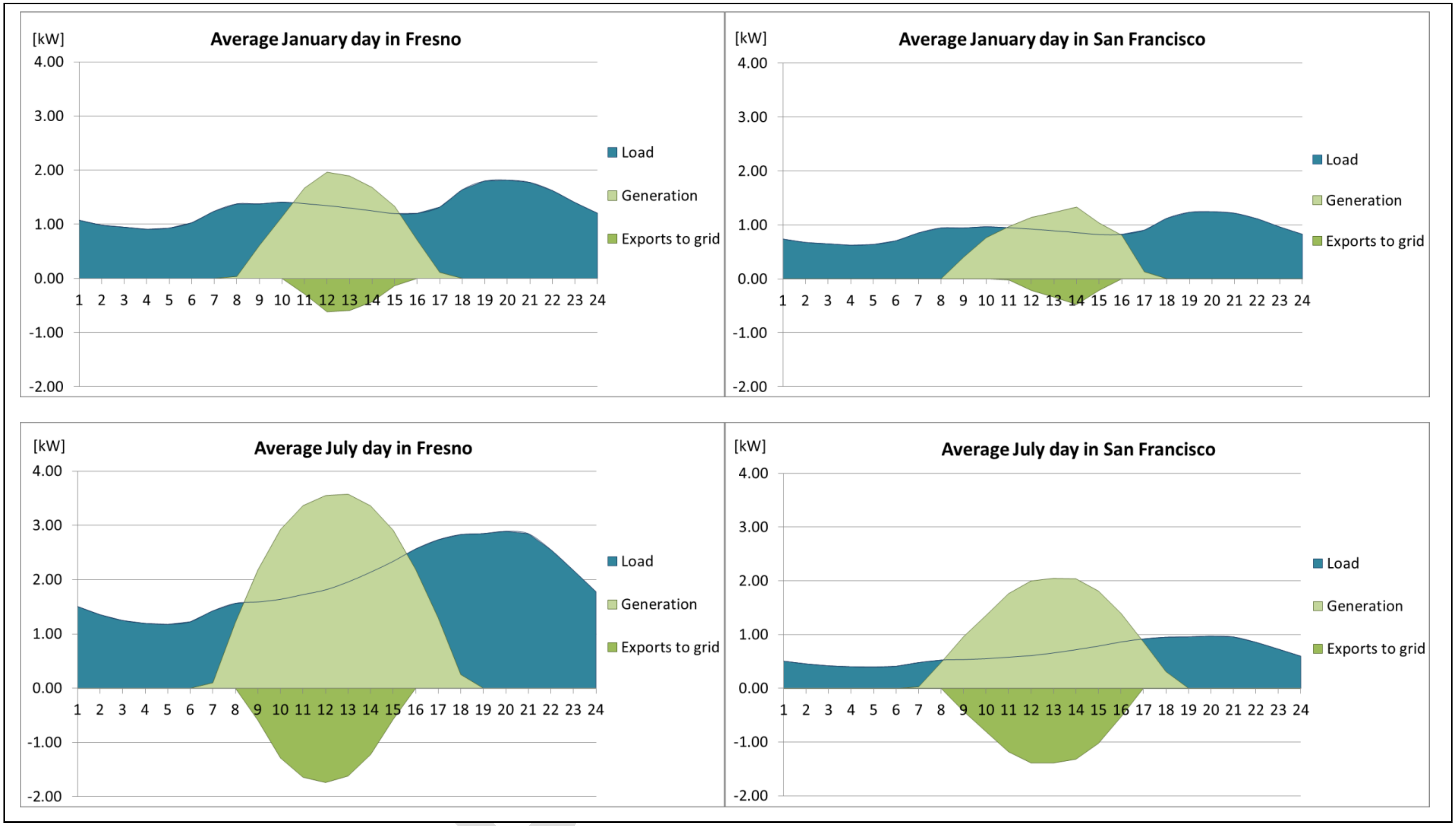

FIGURE 6: Load, PV generation and exports to the grid on an average January and July day, respectively, for a high load household in Fresno and San Francisco.

Returns under Four Different Tariff Structures

Figure 7 presents the net present value (NPV) of investment in a PV system for high load households in Fresno and San Francisco under the four different tariff structures given a 5% discount rate. Overall, we find positive NPV for all tariff structures using conservative assumptions about solar PV installation costs and forecasted growth in retail rates. Regardless of tariff structure, returns are generally much higher in Fresno than in San Francisco. This is partly driven by returns being scaled by the size of the PV system: given the higher load in Fresno, these customers will have installed almost twice the PV capacity as a representative household in San Francisco. Hence, total investment costs and generation capacity are not the same across locations. However, even when comparing NPV per kW installed, returns are still greater in the Fresno area; this is driven by the larger consumption in the top tier and greater generation capacity (more sun hours) in the Central Valley relative to the coast.

Four-tiered IBR vs Two-tiered IBR

For high load customers, comparing across tariff structures, returns are significantly lower under the proposed two-tiered IBRs than under the current four-tiered IBRs. The reason, as previously discussed, is that high load customers are paying the top tier rate for much of their load and under the proposed two-tiered IBR the top tier rate is significantly lower than under the four-tiered IBR. Thus, the average electricity rate for high load users is lower under the two-tiered IBRs than under the four-tiered IBRs, leading to decreased savings from PV investments under the proposed two-tiered IBRs.

As can be seen from Figure 8, the opposite is true for a household with average load: savings from PV investment are higher under the two-tiered IBRs than under the current four-tiered IBRs. Because the proposed new bottom tier rate is higher than the current bottom tier rate, average load households (who consume little to no electricity in the top 3 or 4 tiers) face higher average rates under the proposed two-tiered IBRs than under the current four-tiered IBRs. Thus, the proposed IBRs provide a greater return for these average load households, as they are able to net generation off of higher prices. This result, however, is not very robust to changes in the assumptions about the starting values of the two-tiered rates.

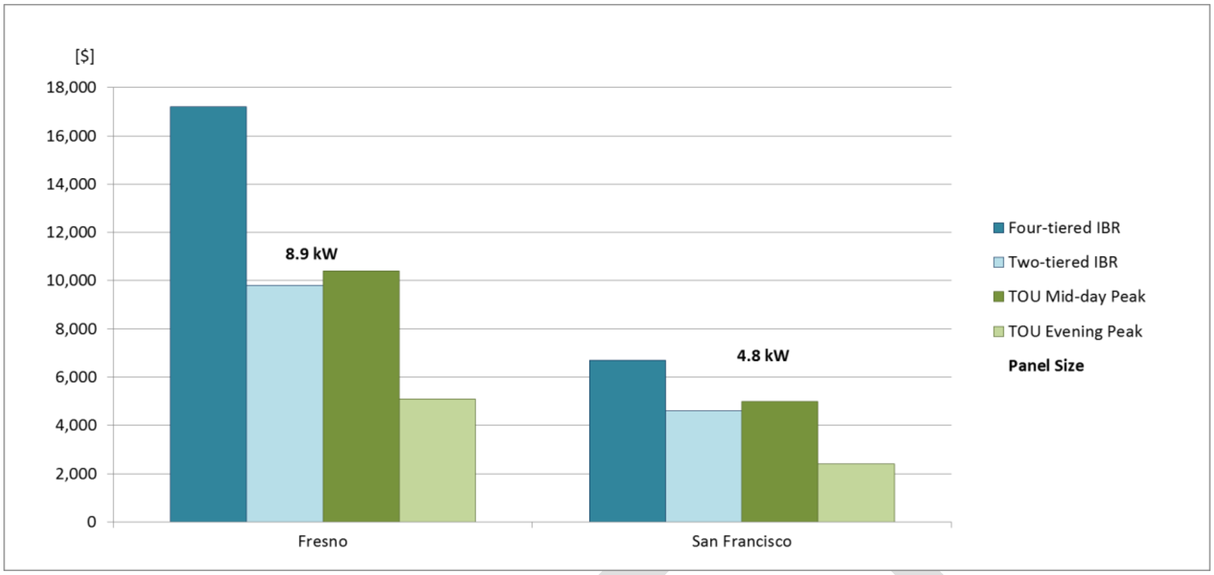

FIGURE 7: Net present values of PV investment for a high load customer in the Fresno and San Francisco area under four-tiered and two-tiered inclining block rates, as well as time-of-use rates with a mid-day peak window and an evening peak window, respectively.

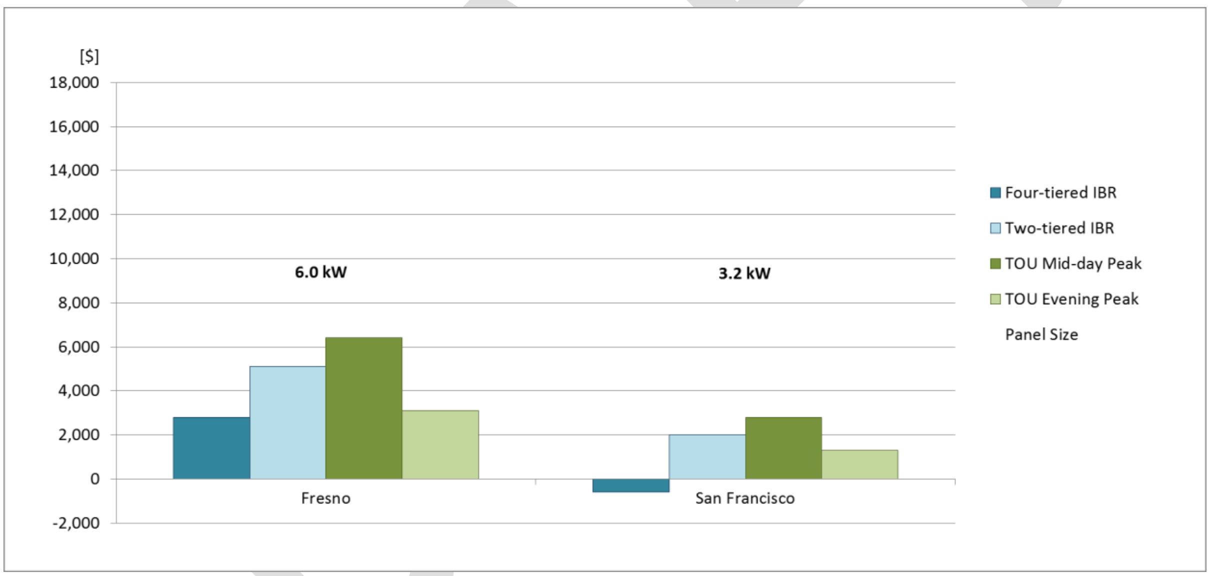

FIGURE 8: Net present values of PV investment for an average load customer in the Fresno and San Francisco area under four-tiered and two-tiered inclining block rates, as well as time-of-use rates with a mid-day peak window and an evening peak window, respectively.

NOTE ON FIGURES 7 AND 8: Mid-day peak refers to a peak between 1 and 7 pm in the summer and 5 and 8 pm in the winter and the evening peak to a window between 5 pm am and 8 pm in both seasons. Numbers in kW refers to the size of the PV system which is scaled to cover the yearly load. The discount rate is 5%.

TOU Rates

For TOU rates with a mid-day peak window, returns for both average and high load households are generally higher than with the two-tiered IBRs. Returns are larger because in the TOU setting, households are generating most electricity during the peak time, when the price is high (32 cents in the summer), while in the two-tiered IBR, the household nets off of the top tier rate (21 cents).

As expected, returns are significantly lower with TOU rates with an evening peak window since the high rate no longer applies at mid-day when most of the electricity is generated by the PV system. Hence, the total value of the electricity generated by the PV system is lower with an evening peak window, although this rate still generates positive NPV.

Additionally, as discussed in the previous section, a household that is currently on IBR can incur additional savings just from switching to TOU rates with a mid-day peak window (without investing in solar panels). While these savings are independent of whether the household invests in a PV system or not, they do depend on the size of the household load. Under IBRs, a high load household will face higher average rates than an average load household, thereby accruing greater savings from switching to TOU rates. Results on the NPV of the bill savings from the switch from four and two-tiered IBRs to TOU rates are presented in table B4 in Appendix B. Generally, savings are positive for high load households. In contrast, savings for average load households in most climate zones are small or negative. Even so, the NPV of investing in a PV system and switching to TOU rates is still higher than investing in a PV system and staying on the two-tiered IBRs for an average load household.

Smaller Panels and Inclining Block Rates

We have so far looked at ROI for the maximum size panels which cover 100% of household load. However, with IBR it is clear that savings per kWh will be the highest by having a PV system that covers the top and most expensive tiers. Figures 9 and 10 illustrate this by comparing the NPV per installed kW for a PV system that covers 50% of household load with returns from a PV system that covers 100% of load.

Figure 9 shows that for a high load household it is more profitable both in the Fresno and San Francisco areas to install a system that only covers 50% of household load under the current four-tiered IBRs. Under the proposed two-tiered IBRs, however, this relative profitability of a smaller system is not as pronounced as under the current four-tiered IBRs, due to the smaller difference between the top and bottom tier rates.

Figure 10 illustrates the comparable results for the average load households. In both regions under the current four-tiered IBRs , it is more profitable (in both absolute terms as well as in dollars per kW installed) to install a system that covers only 50% of household load rather than double the cost by investing in a system twice as large. Especially in San Francisco, where an average household has very little consumption in the top 4^{th} tier, the returns from purchasing a large system are negative. Under the proposed two-tiered IBRs, this relationship no longer holds in absolute $ amounts; however, in terms of returns per kW installed, it is more profitable to install a system that only covers 50% of household load. These results demonstrate that until the upfront costs of PV installation drop substantially, smaller PV systems will be more profitable for most types of households.

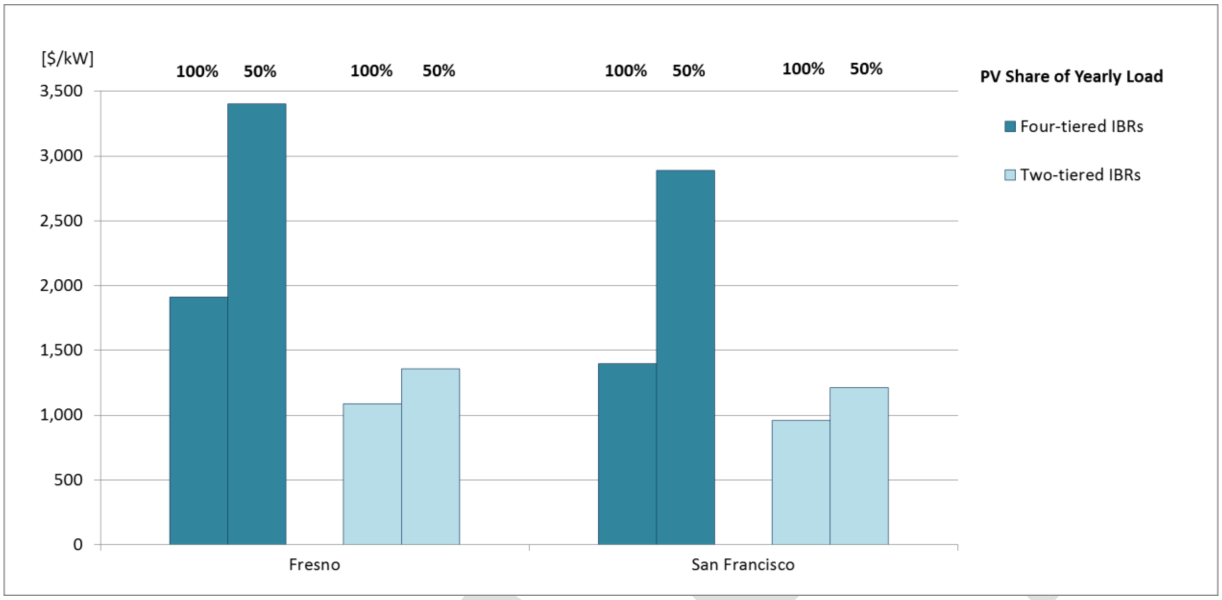

FIGURE 9: Returns in NPV per installed kW for a high load household with a panel with 50% versus 100% load coverage under four-tiered and two-tiered IBRs, respectively.

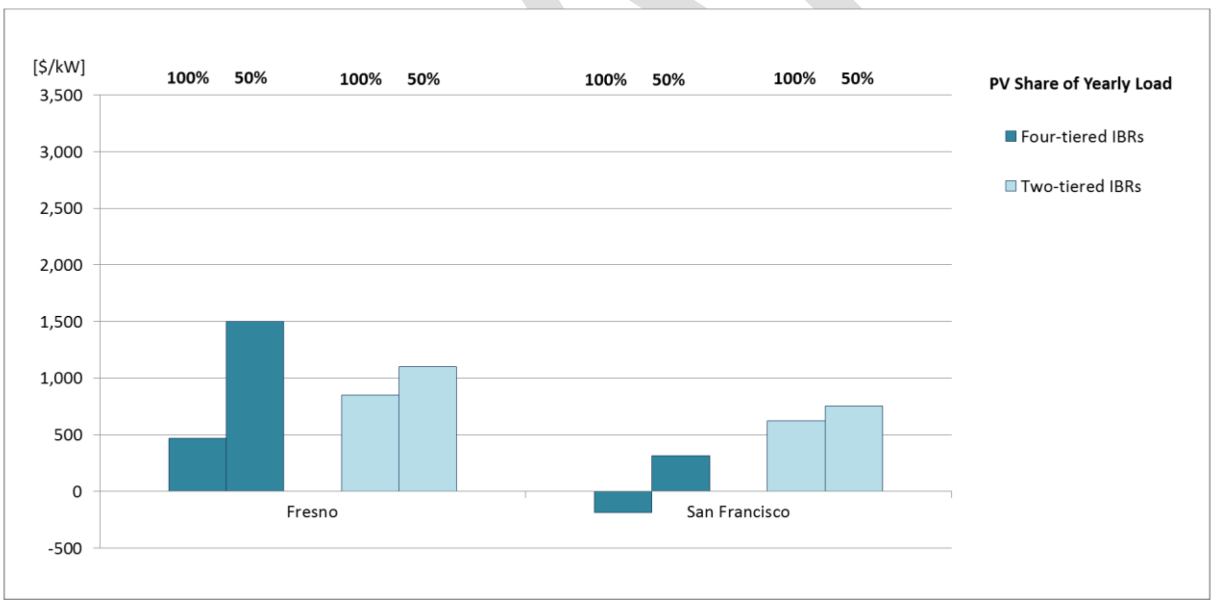

FIGURE 10: Returns in NPV per installed kW for an average load household with a panel with 50% versus 100% load coverage under four-tiered and two-tiered IBRs, respectively.

The Break-Even Value of Solar Tariff

We also asked what the Value of Solar feed-in tariff would have to be to generate positive returns to PV investments. Another way of interpreting this value is the nominal dollar cost of the PV system monetized in kWh over the lifetime of the system. VOS tariffs are generally held fixed over the course of the system lifetime; thus, we do not change the value of the tariff as we otherwise would with the underlying tariffs.

The break-even tariff is approximately 22 cents per kWh in most climate zones, which is significantly higher than Austin Energy's Value of Solar tariff of 13 cents. Hence, a VOS tariff at the level of Austin Energy's would not be high enough to generate positive returns on residential PV investment in northern California. Comparing the break-even VOS to the average rate under the current four-tiered IBRs, we find that in San Francisco the first year average rate without a PV system (21 cents) is actually lower than the cost of PV generated electricity (22 cents). However, because we assume that the average rate faced by the households increases over time (whereas the cost remains fixed over time), so do the savings from PV generated electricity. We therefore find positive returns from PV investment as presented in the previous section.

While Austin Energy's VOS tariff is not high enough to spur investment in the PG&E territory, another concern with this style of feed-in tariff is that the value is fixed throughout the day and the year, although the true value of solar varies hour by hour and day by day. If the utility were to truly value DG, it should price peak time generation higher than off-peak generation, which could potentially change this result.[16]

The Break-Even PV-Specific Grid-Connection Fee

With reference to the monthly surcharges for PV owners introduced in Oklahoma and Arizona, here we estimate what level of a monthly grid connection fee would cause PV owners to break-even on their investment. Given unchanged electricity rates, this charge will only affect the ROI if the monthly surcharge is specific to PV owners.[17] The break-even PV-specific monthly surcharge depends on the household load as well as the underlying tariff structure and is a reflection of the NPVs presented in the previous section. All results on break-even connection fees can be found in table B6 in Appendix B.

In Fresno, a monthly surcharge of $60 under the proposed two-tiered IBRs or the proposed TOU rates would still allow for positive returns on investment for high load households. In San Francisco, the break-even amount for high load households is $30 per month under the same tariff structures. Under TOU rates with an evening peak window, the monthly surcharge in both locations would need to be much smaller (about half the size) to still allow for positive returns on investment.

In contrast, average load households must face much smaller surcharges than high load households: a $30 surcharge in Fresno and a $10 surcharge in San Francisco would allow for positive returns under the proposed two-tiered IBRs or the proposed TOU rates.

[16] This style of analysis is outside the scope of this paper.
[17] It might be the case however that the introduction of monthly surcharges for all customers brings down the electricity rates that the utilities have to charge to fulfill their revenue requirements. This would then indirectly reduce the returns to PV investment under net energy metering since the savings from having PV generated electricity instead of buying electricity from the grid are lower with lower volumetric rates.

Discussion

Model Limitations and Uncertainty

Like most forward-looking analytical exercises, we have forged forward in the face of significant uncertainty. We list here three principle components to uncertainty in our model.

1. Uncertainty about values used for model inputs. We have developed scenarios for electricity rates over the lifetime of a solar panel but future rates and compensation mechanisms are subject to considerable uncertainty. We further make assumptions about future electricity consumption, price responsiveness and the lifetime of the panel. We analyze the significance of these assumptions in the sensitivity analysis found in Appendix C.

2. Uncertainty about scope and scale of the model. We consider solar PV investment in isolation, but other potentially significant investments, such as storage batteries, electric vehicles or appliance upgrades that provide financial returns, are not represented in our study.

3. Uncertainty about factors behind investment decisions. SolaROI represents cash flows for customers but it cannot, for example, represent other factors that may drive investment. For example, households may choose to install a solar panel because of environmental awareness or other idiosyncratic reasons. Our model does not model the decision to purchase a system; instead, it compares outcomes across different pricing structures given that the household has already chosen to make the investment.

Household Uncertainty

It is important to note that while our model is deterministic, owning a solar panel is far from that. There are many uncertainties and risks that the homeowner faces when choosing to install a solar panel.

The first uncertainty is related to the solar panel itself. Similar to other purchases of large and expensive appliances, the lifetime of the solar panel is not perfectly known apriori. Currently, solar panel manufacturers often provide a standard 10-year warranty for panel damage and a 25-year warranty that the system's generation efficiency will not fall below 80%. However, the panel could be damaged after the warranty expires, resulting in a total failure of the panel or required, potentially costly, maintenance. Thus, the homeowner faces financial risk that is similar to purchasing other large appliances such as vehicles.

The second type of uncertainty has to do with the change in prices over time. We assume a growth rate of electricity prices, however, the change in prices is not deterministic over time. Changes in rates are generally done in a discrete fashion, as utilities undergo rate cases every few years, resulting in large and periodic rate changes rather than slowly increasing year by year. Of course, PV investments provide consumers risk security from potential electricity price surges. Solar PV direct generation alternatives, once installed, have virtually zero risk of price fluctuation per kWh of generation. Hence, even if the ROI is uncertain because of the uncertainty surrounding the future price of grid electricity, investment in a PV system can be seen as way for consumers to hedge against the risk of high future price increases on electricity.

A third type of uncertainty deals with changes in demand. Homeowners choose a PV system size that will cover some amount of their load. Unforeseen changes in demand after the solar panel has been installed will result in a sub-optimal system size given the new demand (whether it is larger or smaller), changing the NPV over the course of the panel lifetime.

A fourth important risk factor for the homeowner that is not able to be modeled in SolaROI is the probability of moving. The majority of solar panel manufacturers only provide a warranty if the solar panel remains in its original location, and moving the solar panel may not be feasible for a number of other reasons. In moving, the homeowner loses the future stream of benefits from their investment, and therefore may require a higher price for the sale of the home to compensate for future solar benefits. Dastrup et al (2012)[18] demonstrate that a solar panel adds to the resale value of the home, and the increase in the price may be substantial given non-monetary perceived benefits associated with solar (such as demonstrating "greenness"). However, the homeowner does still face a risk that moving will not allow them to recover their entire investment, especially if she lives in an area where little importance is placed on the perception of environmental friendliness.

Finally, household attitudes towards uncertainty and risk and capital constraints are also important determinants. To some extent, risk attitudes can be represented through the choice of discount rate or the adjustment of future costs and benefits to their certainty equivalents. However, we do not know enough about underlying preferences or the uncertainties involved to adjust the discount rate or future costs and benefits accordingly. We therefore use a standard level of a household's cost of capital and recognize that the influence of uncertainty may make the expected ROI as perceived by the household different from our estimates.

Conclusions and Next Steps

Our analysis has evaluated how PG&E's future rate proposal for northern California impacts the returns from residential PV systems. PG&E's proposal can be seen as part of a general trend across the country in which utilities and regulators are proposing higher fixed monthly surcharges and lower volumetric rates – a trend that will have large implications for PV customers compensated through net energy metering. Our results show that the returns on investment would significantly go down with a change from PG&E's current four-tiered inclining block rates to the proposed two-tiered inclining block rates. This conclusion, however, only applies to high load households. For a household with average load, returns to PV investment actually increase with a change from the current four-tiered to the proposed two-tiered IBR. The latter result, however, is sensitive to the choice of first year values for the two-tiered IBRs.

[18] Dastrup, S.R., J.G. Zivin, D.L. Costa, M.E. Kahn (2012). Understanding the Solar Home price premium: Electricity generation and "Green" social status. *European Economic Review*, 56:pp. 961–973.

Under the simplified voluntary TOU rates proposed by PG&E, the returns on PV investment are generally on par with returns under the proposed two-tiered IBR for high load households. For average load households, returns are instead somewhat higher under TOU rates than under the two-tiered IBR. Furthermore, for households that are not already on TOU rates, those with high loads can generally incur additional savings from switching from IBR to TOU rates. For lower load households, a switch to TOU rates without PV investment may instead actually lead to higher electricity bills. However, the returns to PV investment are still high enough to make combining a PV investment with a switch to TOU profitable also for lower load households.

The price on PV generated electricity - similar to Austin Energy's Value of Solar tariff - that would cause the PV owner to break even on their PV investment is approximately 22 cents per kWh in most of PG&E's service territory. This break-even Value of Solar is the minimum tariff amount that would be required to still stimulate further investment in residential solar PVs if a Value of Solar tariff were to replace NEM as the compensation mechanism for residential solar electricity generation. The break-even value of 22 cents is significantly higher than Austin Energy's Value of Solar tariff of 13 cents. Hence, if a non-time varying Value of Solar tariff at the level of Austin Energy's would replace NEM as the compensation mechanism for residential PV, it would risk quenching continued expansion in residential solar installations in northern California.

The ROI for solar PV systems also depends significantly on the way distribution level costs will be allocated in future. While the grid service provider may assert fixed charges specific to PV owners to cover part of these costs, those charges cannot exceed the point where customers would choose to break their grid tie. Our results show that this break-even surcharge varies significantly with household load, location and tariff structure but under the proposed two-tiered inclining block rates we find that as long as the surcharge is less than 10 dollars per month, returns to PV investment remain positive for both average and above average electricity users in all climate zones but one (zone Z).

A possible emerging trend is the introduction of minimum bill instead of fixed charges for solar customers. Such a compromise has been agreed upon by solar advocates and the electric utilities in Massachusetts.[19] While a minimum charge would increase savings compared to a PV-specific fixed charge for the same size panel, it is conceivable that a minimum charge could have the effect of inducing investments in smaller panels to avoid making the minimum charge binding. This is an issue we will explore in future work.

Future work will also analyze the impacts of relaxing the regulations that require customers to size solar PV systems at or below their on-site load. Relaxing such regulations would be critical to be able to exploit the full potential of the distributed clean electricity generation. However, returns for larger size systems of this kind will be determined by how excess generation is compensated. Current levels of compensation based on the utilities avoided cost of generation is likely not sufficient to stimulate investments in panels covering more than the household yearly load. A removal of the existing load constraint would therefore likely have to be combined with a

[19] GreenTechMedia (July 24, 2014). Why a Minimum Bill May Be a Solution to Net Metering Battles.

change in how excess generation is compensated or with a switch to a different compensation mechanism than NEM.

In our calculations we assumed 100% down payment by the homeowner. However, many solar panels in California are actually leased by the home owner from a third party under so called power purchase agreements. This is an important market trend, and we will in future analyses look at how these leases need to be designed to allow for positive returns on residential PV investments.

Future extensions to SolaROI will also cover other service territories and states than PG&E's. Other possible extensions of the model include representation of a super-off peak time and a critical peak price component in the TOU tariff. More long term extensions may also include representation of combined technologies, such as storage capabilities and enhanced energy efficiency.

Appendix A: Overview of Method and Data

Our tool, SolaROI, calculates returns on investment (net present value, internal rate of return and payback period) on a residential solar PV installation for electricity consumers in PG&E's service territory in northern California. Electricity bill savings from PV installation under net energy metering is determined by the underlying tariff structure. Our tool allows the user to analyze returns under two types of tariff structure: inclining block rates with a maximum of four tiers and time-of-use rates with one contiguous peak window.

Method

Climate Zones

PG&E is separated out into 10 different climate zones, as shown in Figure 3. PG&E's inclining block rate differs across climate zones given the varying needs for energy in different parts of the state - for example, hotter zones receive larger lower tiers in order to allow for a more equitable outcome across the state. This is very clear in the difference between the climate zones that encompass Fresno and San Francisco. As can be seen in Table 1, foggy San Francisco has much smaller allowances in the bottom tiers than in the sunny, hot Fresno area, leading to overall higher average prices for a customer living on the coast relative to a consumer in the Central Valley. This implies certain differences across areas - while households in the Central Valley have a higher need for electricity than someone on the coast, it disincentivizes solar investments in this area relative to the coast through two mechanisms. First, a lower average price means a lower bill with the same level of utilization, leading to less incentive for energy efficiency measures. Second, with NEM, households in the Central Valley will see a smaller return from their solar generation than households on the coast. This large amount of heterogeneity throughout the state makes it very difficult to generalize how returns on investment are affected by pricing structures and highlights the importance of allowing for a flexible model that looks at different consumer groups. Our model adapts to individual heterogeneity by allowing estimation of ROI by different climate groups, different levels of electricity needs (low-high), and different elasticity levels (both in terms of overall price sensitivity as well as ability to substitute between peak and off-peak hours).

Electricity Consumption

Data on aggregate kWh demanded each month for each climate zone for 2011-2012 were collected from PG&E. While these data tell us overall load, we unfortunately do not have access to data describing the load shape (i.e., which percentage of the total load is consumed at each hour of the day) differentiated by the climate zone. In lieu of this, we assume that the load shape does not vary by climate zone and utilize data on average load shape for the residential sector throughout the PG&E territory. We impose this load curve onto the total monthly demand, essentially shifting each climate zone's particular curve up or down.

Imposing the load curve onto the average household electricity usage per month provides us with electricity consumption of a representative average home in each climate zone. Since we only have the consumption of an average consumer, we also generate load shapes for two other types of consumers: one with electricity consumption 50% higher than the average, and one with electricity consumption 100% higher than the average. Since solar panels are generally installed in households with higher than average load, we believe that it is even more important to model ROI for households that do not represent the average. Our model therefore allows the user to specify the size of the load for a representative household within each climate zone.

We begin with one year's worth of data on household electricity consumption and use this as the baseline demand quantities. For each subsequent year, we assume that there is an exogenous demand shift which may be positive or negative. A positive exogenous demand shift would be from an increase in electricity utilization, such as from purchasing more appliances, moving to larger homes, etc. A negative exogenous demand shift could be due to increasing energy efficiency policies being enacted. Our default value (0.7%) is taken from the EIA 2013 Annual Energy Outlook's projection for demand growth between 2011 and 2040. We therefore impose a yearly exogenous 0.7% increase on top of the baseline demand for the first year.[20] However, we allow the user to specify a negative value if she believes the opposite assumption is more likely.

Elasticities

Prices affect demand for electricity at the household level through elasticities - if a household is very responsive to prices (and therefore elasticities are high), an increase in average price per kWh will have a larger effect on demand. The tariffs a consumer faces changes over time due to the projected growth in electricity prices (specified by the user) and they also change when a consumer switches to TOU from inclining block rates. In the former situation, we model the change in consumption across months throughout the lifetime of the solar panel (25 years) as prices increase over time.

When it comes to estimating the change in consumption from the adoption of TOU prices, we need to take into account two different elasticities. The first is the own-price elasticity: the average price faced by the consumer may increase or decrease depending on the relative prices across the different pricing mechanisms. In the case of the TOU option described in Table 2 with an 8 hour peak window, the average price will depend on the number of kWh consumed during the peak and off-peak periods, whereas the default tiered pricing option only depends on total kWh consumed in the month. If the household has less consumption during the peak window than in the off-peak window, the average price may very well decrease with a shift to TOU.

The second elasticity that needs to be taken into account is the substitution elasticity. This defines how much of the total load a household is able to shift or substitute from the peak period to the off-peak period. The more potential shifting behavior, the lower the average price faced by the household.

We utilize estimated elasticities from the 2004 California Statewide Pricing Pilot (CSPP), a pilot run by CA's three investor-owned utilities to test the impact of TOU and dynamic pricing. CSPP estimated own price and substitution elasticities from a residential TOU treatment in four

[20] We impose this exogenous shift in demand prior to estimating what would happen to demand from the increase in prices over time.

different seasons throughout the year. We apply these elasticities for individuals in order to model changes in behavior as prices increase from year to year along with any changes in prices from adoption of TOU pricing. The elasticity of substitution estimated in the CSPP is defined in the following way:

$$\varepsilon_{sub} = \frac{\left[\Delta\left(Q^{peak} / Q^{off-peak}\right)\right] / \left(Q_{tier}^{peak} / Q_{tier}^{off-peak}\right)}{\left[\Delta\left(P^{peak} / P^{off-peak}\right)\right] / \left(P_{tier}^{peak} / P_{tier}^{off-peak}\right)}$$

where Q is the quantity of electricity demanded (in peak or off-peak times), P is the price, and Δ describes the change in the quantity demanded or the price when shifting from tiered prices to TOU. This allows us to estimate the shift in demand from peak to off-peak times when a household switches to a proposed TOU schedule by using data on current quantities and prices.

For estimating how overall consumption is affected by a change in average prices (either from a shift to TOU or a different IBR schedule or from imposing the price trend year to year), we use the formula as defined in the CSPP:

$$\varepsilon_{daily} = \frac{\left[\Delta\left(Q^{daily}\right)\right] / \left(Q_{tier}^{daily}\right)}{\left[\Delta\left(P^{avg}\right)\right] / \left(P_{tier}^{avg}\right)}$$

where Q_{daily} describes the total daily electricity consumption, P_{avg} describes the average price given the consumption across tiers or peak and off peak times, and Δ describes the change in quantity demanded or average prices when shifting from tiered prices to TOU or when facing a higher IBRs. Using data on elasticities and observed quantities and prices, we can estimate how overall consumption changes with a change in price.

CSPP estimates elasticities for outer winter (November, March, April), inner winter (December-February), outer summer (May, June and October), and inner summer (July-September). We use the elasticities estimated in CSPP as our baseline numbers (Table 3). However, the daily price elasticities (also known as own-price elasticity) estimated are significantly higher than other elasticities estimated in similar papers such as Ito (2014) who finds elasticities less than -0.09. Due to this, we set the CSPP elasticity as the high estimate, and allow the user to assume medium elasticities that are ½ the CSPP estimates and low elasticities that are ¼ the CSPP estimates. With regard to the substitution elasticities, there is little evidence of how large or small these actually are, and so we use the CSPP values as the default low value and allow the user to choose substitution elasticities that are higher by either 50% or 100%. This allows us to model how TOU pricing can impact ROI if substitution capabilities increase. As Faruqui and Sergici (2010) demonstrate, TOU pricing supplemented with enabling technology can help consumers shift greater amounts of consumption from peak to off-peak times than TOU pricing alone. We therefore allow the user to specify higher substitution elasticities in order to indirectly model the impact of enabling technologies.

TABLE A1: Elasticity Estimates from CSPP.

Month	Own-Price Elasticity	Substitution Elasticity
January	-0.20	-0.11
February	-0.20	-0.11
March	-0.17	-0.02
April	-0.17	-0.02
May	-0.14	-0.06
June	-0.14	-0.06
July	-0.12	-0.10
August	-0.12	-0.10
September	-0.12	-0.10
October	-0.14	-0.06
November	-0.18	-0.02
December	-0.20	-0.11

Another price effect occurs from the generation itself under tiered pricing and NEM, given that the household now faces a lower average price once the meter runs backwards. We impose the elasticity onto the new quantity demanded given the change in price. This implies that the household will lose some of the benefits associated with the decrease in net consumption (also known as a rebound effect). For households under TOU pricing, we do not impose elasticities at this step, because we assume that they are responding to marginal prices rather than average prices (Ito 2014), and these are not affected by quantities generated.

Solar Generation and PV System Size

Modeling the amount of solar generation for a solar panel owner within a certain climate zone requires knowing two things: the amount of solar that can be generated at that geographic location and the size of the solar panel a household would choose to own. These two things are intricately related, as the greater the generation potential, the smaller the required PV system size. We therefore allow the user to specify a certain amount of load that the household chooses to cover with solar generation- 25%, 50%, 75% or 100% of yearly average load. If the household chooses to cover 100% of average load, it implies that in certain parts of the year (generally, the summer months) the household will be a net producer, while for the remaining months the household will be a net consumer.

We then need to figure out how large the solar panel needs to be to cover the required load given the solar generation potential of the household's location. In order to do this we utilize data from NREL's PVWatts calculator, which calculates the amount of solar energy generated by a 1 kW fixed roof mounted solar panel system each hour of the day over the course of the year for a particular weather station in the zip code provided. We choose representative zip codes for each climate zone, finding weather stations near the center of the climate zone if possible. PVWatts calculates the optimal Array tilt and azimuth given the latitude and longitude of the zip code provided, and thus the generation data vary across region, although all regions have an azimuth of 180 degrees and a tilt of around 40 degrees. Since the data are provided hourly throughout the year, we average over the days of each month to generate one kW value for each hour of the day of each month (i.e., we generate hourly load for 12 representative days in the year). Since these values demonstrate the generation for a 1 kW system, we first calculate the total generation throughout the year produced by this system size in the following way:

$$Yearly\_Gen = \sum_{i=1}^{12} Daily\_Gen_i * days_i$$

where i indexes month, $Daily\_Gen_i$ is the amount of generation produced in an average day in month i for a 1 kW system in the specified climate zone, and $days_i$ is the number of days in month i. We then scale this amount up or down depending on the load requirement specified by the user, as defined by the following equation:

$$Panel\_Size = \frac{Average\_Consumption * Load\_Factor}{Yearly\_Gen}$$

where *Average_Consumption* is the household's average consumption over the year, and *Load_Factor* is .25, .50, .75 or 1. This implies that the PV system size will vary with the generation potential and the amount of consumption in the household. This calculation demonstrates, for example, that the system size required to cover 100% of the load for a household in Fresno (8.9 kW) is almost twice as large as the optimal system size for a household in San Francisco (4.8 kW), given larger consumption patterns in the Fresno area.

One aspect that is important to account for is the change in generation capacity of the solar panel over time, as solar panels gradually lose capacity for generation over time. We follow Borenstein (2007) and assume that the generation capability decreases by 1% per year. This decreases the benefits to the solar panel owner over time.

Payment for Household Solar Generation

SolaROI models households that are connected to the grid, which implies that the generation produced by the household will be sold back to the grid in some manner. Currently, PG&E offers a net energy metering system, where the meter essentially runs backwards when the solar panel is producing. This allows the household to net off of their highest observed marginal tier rate under IBR or off the peak rate when generation occurs during peak times. NEM can be very profitable for the household, especially when generation is greater than consumption, in which case the household will not be facing an energy bill and can receive a credit which is rolled over to the next month until the end of the billing year. At the end of the year, if the credit is positive, households in PG&E territory receive an avoided generation charge for any excess generation over the year, which is about 3-4 cents per kWh.

Another compensation mechanism that is being considered but is currently not available in CA is a feed-in tariff, such as the Value of Solar Tariff from Austin Energy. We estimate different

ROI for varying feed-in tariffs and calculate the "break-even" feed-in tariff: i.e., any value above this would result in a profit to the household or a positive NPV, while any value below would result in a negative NPV. Therefore, the break-even price depends only on the price of the solar installation and is independent of the underlying pricing mechanism.[21]

Solar Investment Costs and Incentives

We calculate the cost of installing the optimal solar system size given a number of different data observations. The first is the capital cost covering both the technology and the installation on the roof. NREL estimates this cost to be $5.50/kW DC in 2010; as costs have dropped since then, we assume $5/kW DC. Another major cost of the investment is the inverter, whose price is calculated by multiplying the optimal system size with the inverter cost per kW DC ($22022). We assume the inverter is replaced every 8 years, as average time to failure is between 5 and 10 years.23 Furthermore, we assume that the cost of the inverters fall by 2% each year.24 We also assume some operation and maintenance costs each year, specifically to deal with issues such as cleaning of the solar panels or potential maintenance required from animals nesting or chewing through wires.

There exist some governmental rebates for the installation of the solar panel; specifically a 30% federal tax rebate. Our model allows us to estimate how ROI changes with and without the federal tax rebate, as this incentive will likely soon disappear. CA State rebates used to be provided but no longer exist in the PG&E territory; we allow the user to specify a positive rebate at the state level, although the default value is 0.

Calculating Bills and Returns on Investment

We calculate the monthly bill statement for the representative household given the underlying electricity demand, generation, and tariff structures. For homes with tiered rates and NEM compensation, we calculate the bill they would be facing once we subtract their monthly electricity generation. This implies that, for example, a household in Fresno in the winter with electricity consumption of 977 kWh and generation of 517 kWh will only pay for 460 kWh, thereby avoiding paying the two highest tiers. This effectively decreases the average price they face by 10 cents per kWh.

However, if they face a different compensation mechanism, such as a feed-in tariff, they will still pay the high tiers for their 977 kWh while receiving a flat rate for the 517 kWh. In this example, the break even rate (22 cents) would decrease the bill by approximately 55%, although their resulting bill payment will still be higher than their bill under NEM. Given that Austin's VOS tariff is around 13 cents, it is clear that NEM is substantially more beneficial to the PV customer than a feed-in tariff.

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[21] We assume that the feed-in tariff does not change over time. While it may conceivably decrease, as has been the case for Austin Energy's VOS tariff, there is uncertainty over how it will change. Our model allows the user to specify a certain rate of increase or decrease to the tariff if she has an apriori belief about the rate of change.

[22] http://tinyurl.com/mkblxvj

[23] Borenstein 2007 page 10

[24] Ibid.

To estimate the impact on bills from TOU prices, we first utilize the data on electricity consumption under tiered rates in the first year as the baseline. We formulate a new baseline for TOU customers by adjusting this first year's consumption given the change in average price from tier to TOU pricing and the shifting from peak to off-peak consumption. After the first year, we impose the exogenous demand shift and exogenous price increase on this new TOU baseline. Once the household has changed its behavior given the change in prices, we then calculate the bill by multiplying the off-peak price with the off-peak quantities and adding to that the product of the peak price with the peak quantities. If the household is generating under NEM compensation, we then calculate the amount of net peak and net off-peak quantities that remain and credit these to the next month at the respective peak and off-peak rates. At the end of a twelve month period, the cumulative credits and debits over the past year is calculated and billed to the household. If there is a positive credit at the end of the twelve month period, the avoided generation cost is paid for any excess generation. In this case, the household is able to avoid paying any high peak prices and is able to benefit from lower off-peak prices.

We calculate the bills month by month throughout the lifetime of the solar panel (we use a default value of 25 years though this length is also adjustable by the user) for all different tariff structures and compensation mechanisms. Our next step is to calculate the return on investment by comparing the stream of solar costs (installation, inverter replacement, maintenance, etc.) to the stream of benefits from reduced bills. In order to do this, we first calculate the benefit month by month by comparing the reduced bill under generation to the higher bill under no generation. We then apply a discount rate to future benefits and costs (our default value is 5%[25], although this can also be adjusted) and sum across the stream of discounted benefits and costs. This sum gives us the NPV of the investment. We also calculate the payback period for a full upfront investment (i.e., no loan amount) by measuring at which point the cumulative cost stream becomes zero. Finally, we calculate the internal rate of return for households purchasing the solar panels without a loan. If the household takes a loan on the investment, we generate a monthly amortization schedule of the upfront investment, allowing for a user-specified percentage to be paid up front[26]. In this case, we assume a 15 year loan[27] with a 5% interest rate[28] and a 10% down payment.

In our baseline scenario, we impose an exogenous yearly nominal rate of increase in electricity prices of 3% based on the observed increasing trend in average prices in the PG&E territory between 2000 and 2012; and assume that all prices (i.e., peak and off-peak prices and all tiered prices) increase evenly at the same rate.

[25] NREL uses a range of 3-7% (http://www.nrel.gov/docs/fy12osti/52197.pdf, p 13) while Borenstein (2007) uses the average loan rate as a discount rate.

[26] The amount of the down payment can be specified by the user.

[27] http://www.nrel.gov/docs/fy13osti/51644.pdf page 54 states that solar loans are generally paid back within 5-30 years, so we take a conservative approach and choose a more conservative time to not overestimate NPV.

[28] We use the average home loan rate here because many of these solar loans are mortgages.

Data sources

Monthly load data
Hourly load data for PG&E average customers on the E1 (Residential service), E8 (Residential Seasonal Service Option) and E13 plans for the period August 2011 to July 2012. Downloaded from:

http://www.pge.com/nots/rates/tariffs/energy_use_prices.shtml

We use the E1 hourly load data (which is an average of all E1 customers over all climate zones) as the basis for the load profile. Essentially, we assume that all customers throughout the PG&E territory have the same load shape (while this is a strong assumption, we do not have access to differentiated load data). The shape of the load profile from the above data set is matched with data on average monthly electricity use across all of PG&E's climate zones for non-CARE customers over the period August 2011 to July 2012. The tier usage dataset by climate zone was provided directly by PG&E during last year's rate case.

PV Generation
Data on PV output were taken from the NREL online PVWatts model which can be accessed at http://pvwatts.nrel.gov/pvwatts.php. These data provide the amount of potential generation by hour of the day throughout the entire year. For each different PG&E service zone, a representative location was chosen according to Table A2.

TABLE A2: Zone Location

Zone	Location
P	Paradise
Q	Santa Cruz
R	Fresno
S	Sacramento
T	San Francisco
V	Eureka
W	Bakersfield
X	San Jose
Y	Crescent Mills
Z	Echo Lake

Rate structures
PG&E rates and baseline quantities per territory were downloaded from PG&E's website at:

http://www.pge.com/tariffs/electric.shtml#RESELEC_BASELINE

Elasticities
The main estimates for own-price and substitution elasticities were taken from the report on the California Pricing Pilot – Impact evaluation of the California statewide pricing pilot, p.90 and 97. We believe the daily elasticities to be on the high end (so our high elasticity option will reflect this data point) while we think the substitution elasticities may be on the low end (so our high elasticities will reflect twice the size of that data point and the medium elasticities reflect the original).

Downloaded from:

https://www.smartgrid.gov/sites/default/files/doc/files/Impact_Evaluation_California_Statewide_Pricing_Pilot_200501.pdf

PV Costs, Inverter and PV system lifetimes
Estimates on PV costs, inverter costs and PV system lifetimes were taken from:

Speer, B. Residential Solar Photovoltaics: Comparison of Financing Benefits, Innovations, and Options. NREL Technical report. October 2012. Downloaded from

http://www.nrel.gov/docs/fy13osti/51644.pdf

Appendix B: Additional Results

Table B1: Net Present Value of Solar Investment by Zone, Load, and Rate Structure

Zone Choice	Load	NEM IBR (four-tiered)	NEM IBR (two-tiered)	NEM TOU (midday peak)	NEM TOU (evening peak)
P	Average	1,800	4,500	5,900	2,900
	50% Higher	15,100	8,800	9,800	4,800
	100% Higher	28,400	12,900	13,500	6,700
Q	Average	15,000	7,800	7,800	3,900
	50% Higher	32,000	12,900	12,300	6,300
	100% Higher	48,100	18,000	16,800	8,700
R	Average	2,800	5,100	6,400	3,100
	50% Higher	17,200	9,800	10,400	5,100
	100% Higher	31,900	14,300	14,200	7,100
S	Average	2,100	4,500	6,000	2,800
	50% Higher	15,700	8,900	9,700	4,700
	100% Higher	29,600	13,100	13,400	6,500
T	Average	-600	2,000	2,800	1,300
	50% Higher	6,700	4,600	5,000	2,400
	100% Higher	14,600	6,900	7,200	3,400
V	Average	-4,100	-400	1,200	-1,400
	50% Higher	5,300	1,600	2,700	-1,700
	100% Higher	15,500	3,300	4,200	-1,900
W	Average	3,600	5,400	6,800	3,300
	50% Higher	18,800	10,400	10,900	5,400
	100% Higher	34,400	15,100	14,900	7,500
X	Average	500	3,600	4,900	2,600
	50% Higher	11,200	7,400	8,200	4,300
	100% Higher	22,300	10,800	11,400	6,000
Y	Average	-1,800	3,100	4,600	2,600
	50% Higher	7,200	6,800	7,800	4,300
	100% Higher	18,100	10,300	10,900	6,100
Z	Average	-1,800	1,300	2,300	1,300
	50% Higher	500	3,300	4,200	2,500
	100% Higher	6,000	5,600	6,100	3,700

Note: TOU rates with different seasonal peak times: midday peak (Summer 1-7 pm , Winter 5-8 pm) and evening peak for both seasons (both seasons 5-8 pm). TOU NPV refers to a baseline of TOU rate structure with no PV system. Values in 2012 dollars.

Table B2: Payback period of Solar Investment by Zone, Load, and Rate Structure

Zone Choice	Load	NEM IBR (four-tiered)	NEM IBR (two-tiered)	NEM TOU (midday peak)	NEM TOU (evening peak)
P	Average	14	13	12	13
	50% Higher	11	12	12	13
	100% Higher	10	12	12	13
Q	Average	10	12	12	13
	50% Higher	9	12	12	13
	100% Higher	9	12	12	13
R	Average	14	13	12	13
	50% Higher	11	12	12	13
	100% Higher	10	12	12	13
S	Average	14	13	12	14
	50% Higher	11	12	12	13
	100% Higher	10	12	12	13
T	Average	16	13	13	14
	50% Higher	12	12	12	13
	100% Higher	10	12	12	13
V	Average	18	15	15	16
	50% Higher	14	14	14	16
	100% Higher	12	14	14	16
W	Average	14	13	12	13
	50% Higher	11	12	12	13
	100% Higher	10	12	12	13
X	Average	15	13	12	13
	50% Higher	11	12	12	13
	100% Higher	10	12	12	13
Y	Average	17	13	12	13
	50% Higher	12	12	12	13
	100% Higher	10	12	12	13
Z	Average	19	13	13	13
	50% Higher	15	12	12	13
	100% Higher	12	12	12	13

Note: TOU rates with different seasonal peak times: midday peak (Summer 1-7 pm , Winter 5-8 pm) and evening peak for both seasons (both seasons 5-8 pm). TOU NPV refers to a baseline of TOU rate structure with no PV system. Values in years.

Table B3: Internal Rate of Return on Solar Investment by Zone, Load, and Rate Structure

Zone Choice	Load	NEM IBR (four-tiered)	NEM IBR (two-tiered)	NEM TOU (midday peak)	NEM TOU (evening peak)
P	Average	6%	7%	8%	6%
	50% Higher	9%	8%	8%	7%
	100% Higher	11%	8%	8%	7%
Q	Average	10%	8%	8%	7%
	50% Higher	12%	8%	8%	7%
	100% Higher	13%	9%	8%	7%
R	Average	6%	7%	8%	6%
	50% Higher	10%	8%	8%	7%
	100% Higher	11%	8%	8%	7%
S	Average	6%	7%	8%	6%
	50% Higher	10%	8%	8%	7%
	100% Higher	11%	8%	8%	7%
T	Average	5%	7%	7%	6%
	50% Higher	9%	8%	8%	6%
	100% Higher	11%	8%	8%	7%
V	Average	3%	5%	6%	4%
	50% Higher	7%	6%	6%	5%
	100% Higher	8%	6%	6%	5%
W	Average	7%	7%	8%	7%
	50% Higher	10%	8%	8%	7%
	100% Higher	12%	8%	8%	7%
X	Average	5%	7%	8%	7%
	50% Higher	9%	8%	8%	7%
	100% Higher	11%	8%	8%	7%
Y	Average	4%	7%	8%	7%
	50% Higher	8%	8%	8%	7%
	100% Higher	10%	8%	9%	7%
Z	Average	3%	7%	8%	7%
	50% Higher	6%	8%	8%	7%
	100% Higher	8%	8%	9%	7%

Note: TOU rates with different seasonal peak times: midday peak (Summer 1-7 pm , Winter 5-8 pm) and evening peak for both seasons (both seasons 5-8 pm). TOU NPV refers to a baseline of TOU rate structure with no PV system.

Table B4: NPV of Savings from Switch from Inclining Block Rates to TOU (midday peak) rate structure

Zone Choice	Load	TOU midday vs four-tiered IBRs	TOU midday vs two-tiered IBRs
P	Average	-3,200	200
	50% Higher	6,900	2,000
	100% Higher	18,500	3,800
Q	Average	7,900	2,100
	50% Higher	22,000	4,500
	100% Higher	36,200	6,800
R	Average	-3,300	-400
	50% Higher	7,100	1,200
	100% Higher	18,700	2,800
S	Average	-2,300	-200
	50% Higher	6,600	1,400
	100% Higher	17,800	3,000
T	Average	-2,800	0
	50% Higher	2,400	1,100
	100% Higher	8,800	2,100
V	Average	-4,200	0
	50% Higher	4,000	1,700
	100% Higher	14,100	3,300
W	Average	-3,200	-600
	50% Higher	7,200	800
	100% Higher	19,000	2,200
X	Average	-3,500	0
	50% Higher	4,000	1,400
	100% Higher	13,100	2,900
Y	Average	-5,500	-400
	50% Higher	400	900
	100% Higher	8,700	2,300
Z	Average	-3,700	-600
	50% Higher	-3,200	-200
	100% Higher	300	600

Note: Values in 2012 dollars.

Table B5: Break-even levels Value of Solar (VOS) tariff by zone and load

Zone Choice	Load	VOS Break Even [$/kWh]
P	Average	0.22
	50% Higher	0.22
	100% Higher	0.21
Q	Average	0.21
	50% Higher	0.21
	100% Higher	0.21
R	Average	0.22
	50% Higher	0.21
	100% Higher	0.21
S	Average	0.22
	50% Higher	0.22
	100% Higher	0.21
T	Average	0.22
	50% Higher	0.22
	100% Higher	0.22
V	Average	0.26
	50% Higher	0.26
	100% Higher	0.26
W	Average	0.21
	50% Higher	0.21
	100% Higher	0.21
X	Average	0.22
	50% Higher	0.21
	100% Higher	0.21
Y	Average	0.21
	50% Higher	0.21
	100% Higher	0.21
Z	Average	0.21
	50% Higher	0.21
	100% Higher	0.20

Table B6: Break-even PV-specific Grid-connection Fees by zone and load

Zone Choice	Load	NEM IBR (four-tiered)	NEM IBR (two-tiered)	NEM TOU (midday peak)	NEM TOU (evening peak)
P	Average	10	30	30	20
	50% Higher	90	50	60	30
	100% Higher	170	80	80	40
Q	Average	90	50	50	20
	50% Higher	190	80	70	40
	100% Higher	280	110	100	50
R	Average	20	30	40	20
	50% Higher	100	60	60	30
	100% Higher	190	80	80	40
S	Average	10	30	40	20
	50% Higher	90	50	60	30
	100% Higher	170	80	80	40
T	Average	-	10	20	10
	50% Higher	40	30	30	10
	100% Higher	90	40	40	20
V	Average	-	-	10	-
	50% Higher	30	10	20	-
	100% Higher	90	20	20	-
W	Average	20	30	40	20
	50% Higher	110	60	60	30
	100% Higher	200	90	90	40
X	Average	0	20	30	20
	50% Higher	70	40	50	30
	100% Higher	130	60	70	40
Y	Average	-	30	30	20
	50% Higher	40	40	50	30
	100% Higher	110	60	60	40
Z	Average	-	10	10	10
	50% Higher	0	20	20	20
	100% Higher	40	30	40	20

Note: Any (-) implies that there is no positive number which would allow a positive NPV.

Appendix C: Sensitivity Analysis

Baseline Scenario:

Our calculations require making assumptions about the value of a large set of variables for which the value is inherently uncertain. We performed a sensitivity analysis to determine which of these variables are critical to our results. For each variable, we separately tested the effect of changes within a reasonable range on the baseline assumptions – for high load households in the regions of Fresno and San Francisco. We define significant variables as those that result in a negative NPV in their tested range or have an average NPV change of 20% or greater for a 10% variation in the tested variable.

The sensitivity analysis was performed for climates zones of San Francisco and Fresno as these zones have distinctly different patterns for energy consumption and baseline quantity allocations. In Table C1 below, each tested variable is listed with the baseline assumption and the tested range.

Table C1: Analyzed Model Variables

Variable Category	Variable	Base Assumption	Range
PV System Lifetime and Productivity	Lifetime [years]	25	17.5 - 50
	Annual rate of PV productivity change	-1%	0% - 2%
Upfront PV System Costs	Federal Tax Credit for Solar Panel	30%	0% - 30%
	Installation cost [$/Wdc]	5	1 - 10
Reoccurring PV System Costs	Inverter replacement frequency [years]	8	5 - 16
	Inverter Cost Annual Change	(-2%)	(-2%) - 0%
	Inverter cost [$/kW DC]	220	110 - 420
	Operation and maintenance cost [$/year]	100	0 - 200
Discount Factor	Discount Rate	5%	3% - 7%
Electricity Price and Demand	Electricity price annual rate of change	3%	0% – 6%
	Annual electricity demand rate of change	0.7%	(-1.6%) - 1.6%
	Own-Price Elasticity Factor*	.5	(-3) – 3
	Peak Substitution Elasticity Factor*	1	(-3) – 3

*The elasticity factor is a multiplier on the consumer's baseline own-price and substitution elasticities in each month as outlined in Table A1. Thus, a factor of 0.5 divides the assumed baseline elasticity by 2.

Effects of Variable Change by Zone and Rate

Graphs C3-C24 below depict the relationship between NPV and the tested variable for each climate zone and tariff structure. Each variable was changed incrementally throughout the variable range (as defined in Table C1) to show a comparable percent change in NPV per variable, keeping the other variables at their baseline values. The graph scales are consistent between zones so as to easily compare each variable's impact on NPV between climate zones and tariff structures.

Lifetime and Productivity of the PV system

The ability of a PV system to produce benefits over the entire investment period depends on two things. First, it depends on the length of the system's productive lifetime (i.e., PV system life expectancy); the longer the lifetime, the greater the benefits. Second, it depends on how rapidly the system loses productivity in terms of generation potential: similar to most appliances, an older PV system will be less efficient (and therefore produce less) than a newer system. This variable is captured in our variable PV productivity change. Thus we analyze how sensitive the NPV results are to deviations in these two variables from our baseline assumptions.

PV System Lifetime

Our model uses a conservative estimate for the lifetime of the PV system. Current solar panel manufacturers often provide a standard 10-year warranty for panel damage and a 25-year warranty that the system's generation efficiency will not fall below 80%. This is the case for SunPower, Sharp and Kyocera Solar who covered 46% of the California solar panel market in 2011.[29] Thus, our baseline assumptions are in line with this warranty: we assume a 25-year lifetime and a -1% annual change in PV cell production (with this assumed percentage decrease, the productivity will be 80% after 25 years).

Solar panels are a fairly recent introduction to the market and panels with recent technology have not yet been tested after 25 years of use. However, research suggests that panels manufactured about 40 years ago are still generating at 80% of their original capacity.[30] Given these results and current warranties, we test a lifetime range of 17.5 to 50 years.

[29] http://cleantechnica.com/2011/06/16/most-popular-solar-panels-in-california/
[30] http://www.appropedia.org/Lifespan_and_Reliability_of_Solar_Photovoltaics_-_Literature_Review

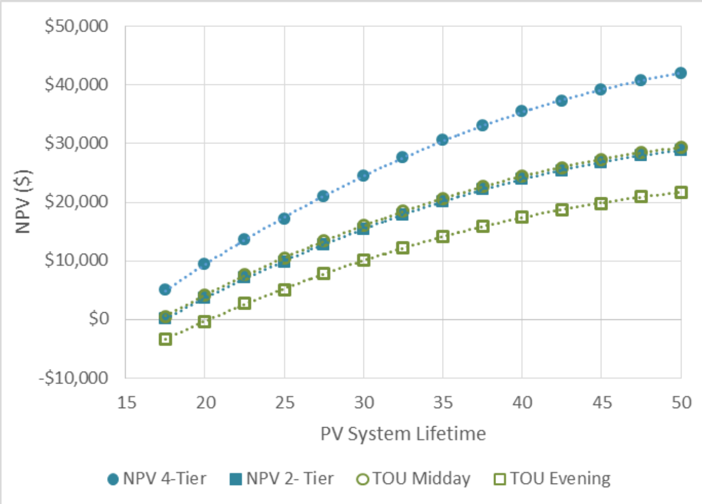

FIGURE C1: System Lifetime, Fresno

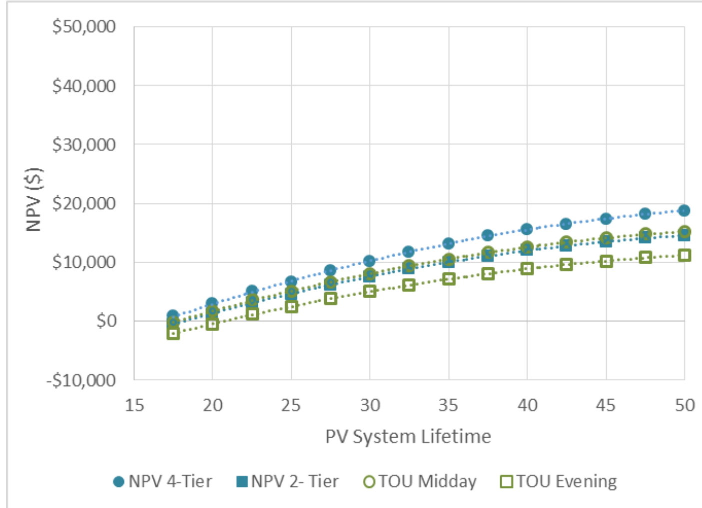

FIGURE C2: System Lifetime, San Francisco

In both zones, TOU with an evening peak is the only tariff structure under which the panel must exceed 20 years of life to result in a positive NPV. Under all other tariffs in both areas, a PV system will have a positive NPV if it lasts at least 18 years.

Under a 4-Tier pricing structure a system with a 40-year lifetime would result in a $16,000 NPV in the San Francisco climate zone and a $35,000 NPV in the Fresno climate zone. This is more than a $8,000 and $18,000 increase, respectively, from our baseline scenario. Thus, if PV systems are able to last as long as 40 years (as research suggests) it will result in large benefits to the PV owner.

Of course, NPV increases with the system's lifetime, as it keeps generating electricity long after the homeowner paid for the system. However, the rate of increase will be lower given that PV production will decrease over time; hence, the future benefits are not only decreased, but they are also less important for NPV given our assumed discount rate. Figures C3 and C4 demonstrate that at approximately 50 years NPV is maximized for all tariff structures and in both climate zones. After this point, the slope becomes negative and NPV decreases with each additional year of panel use. The point at which NPV begins to decrease indicates the time at which the operation and maintenance costs and the inverter replacement cost outweigh the yearly benefits, thereby producing net negative yearly cash flows and decreasing the overall NPV.

PV System Productivity

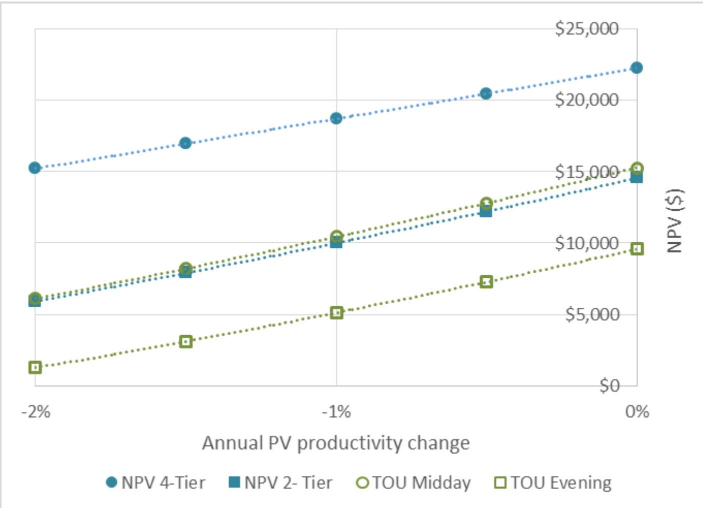

FIGURE C3: Rate of PV Productivity Change, Fresno

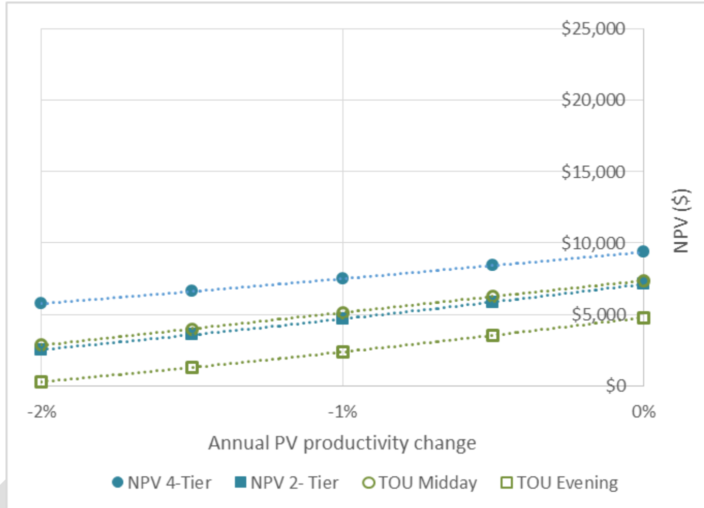

FIGURE C4: Rate of PV Productivity Change, San Francisco

As PV systems age, their generation capacity decreases from 100% of potential generation. Under our baseline assumption (-1%), a panel will generate electricity at 76% of its original potential in year 25 – just under the expected productivity of 80% for the first 25 years. We selected a range of -2% to 0% to reflect the complete range of likely PV productivity change and the standard available panel warranties.

Figures C5 and C6 show the sensitivity of the NPV to the rate of PV productivity change. For all tariff structures and both climate zones, PV investment results in a positive NPV in the entire tested range. Additionally, this tested range is conservative since under the current standard warranties a PV system would only be allowed to decrease to 80% of its generation potential for the first 25 years of use. A -2% PV cell production change would result in generation of 52% of potential at the end of the 25 years of life, which is much lower than a standard warranty would allow.

The slope of the curves in Figures C5 and C6 is slightly different in each zone. This difference in slope reflects the initial generation potential of each zone. An annual 1% decrease in PV cell production in sunny Fresno will result in a larger decrease in total electricity generation than a 1% annual decrease in PV generation in cloudy San Francisco.

Upfront Costs

The upfront cost variables are those that are directly related to the cost of installing a PV system at time zero. These costs are affected by the variables federal tax credit and installation cost.

Federal Income Tax Subsidy

One variable that is likely to change in the near future is the federal tax subsidy. The current subsidy is set at 30%, which means that a solar panel buyer may recoup 30% of his or her panel cost as an income tax credit. We assume that the household can deduct the full amount of this credit from their income tax liabilities. But depending on the size of the PV investment and their income taxes owed it is perceivable that a household would not be able to make use of the entire 30% tax credit. It is therefore relevant to analyze the impact of a lower credit. The 30% tax credit is also currently set to decrease to 10% after 2016[31].

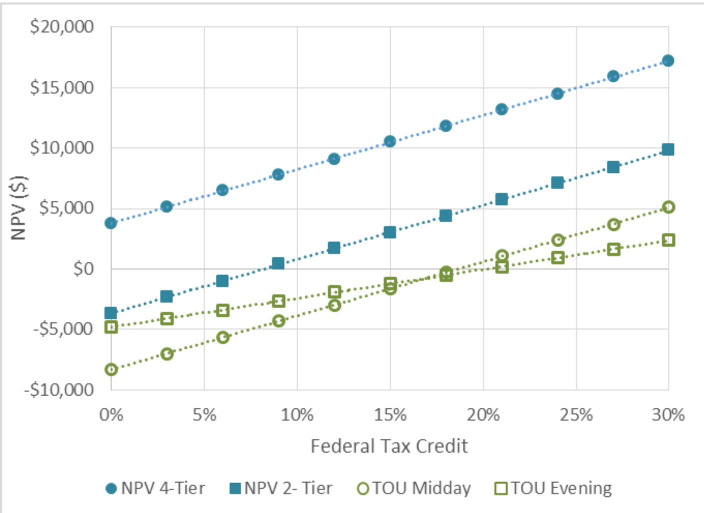

FIGURE C5: Federal Tax Credit, Fresno

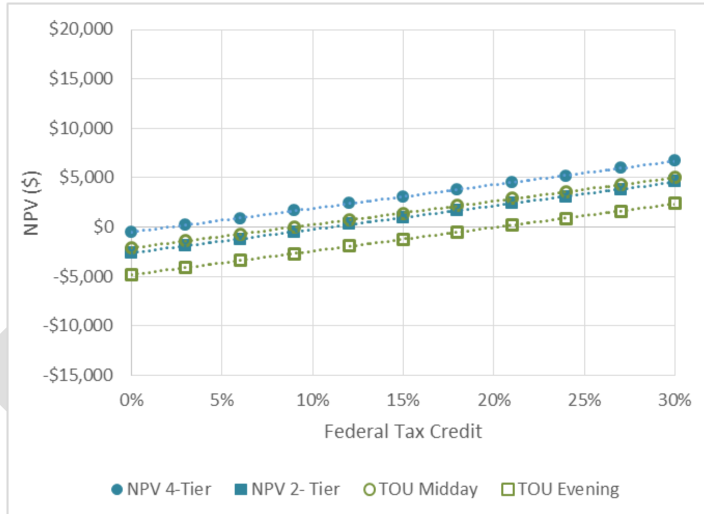

FIGURE C6: Federal Tax Credit, San Francisco

We chose to evaluate the range of 0% - 30% to test the effect of completely removing the tax subsidy as well as the effect of reducing the subsidy. The change or possible expiration of the current federal tax subsidy has a strong, negative effect on the NPV of all PV systems in all zones and under all rate structures. Eliminating the subsidy completely will only result in a positive NPV for households under the 4-Tier rate structure in Fresno, given its high generation potential and the assumed high electricity use of a high load household in that region.

Figures C7 and C8 demonstrate that the slopes of the federal tax credit sensitivity curves are very similar across zones and underlying rates. This is as expected: the tax subsidy is effectively linearly decreasing the price of the initial panel cost by 0% - 30%. The slopes in each zone are identical because the installation cost is directly related to the system size. Larger PV systems, like those needed to cover 100% of average load in Fresno, have a steeper slope since the total installation cost is linearly increasing in the size of the PV system.

[31] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F

Installation Cost

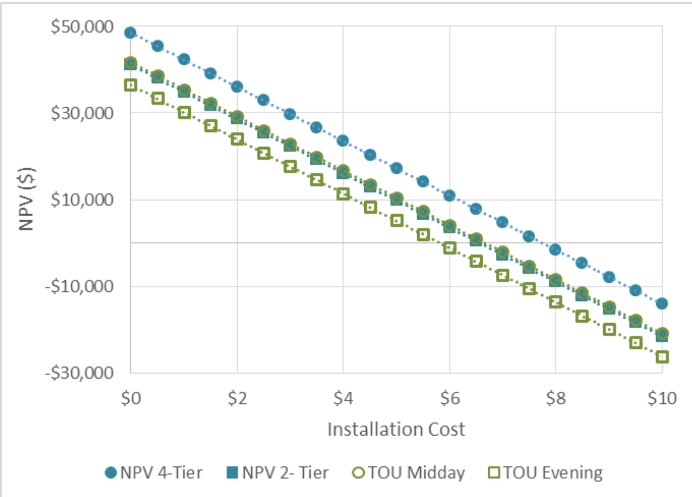

FIGURE C7: Installation Cost [$/Wdc], Fresno

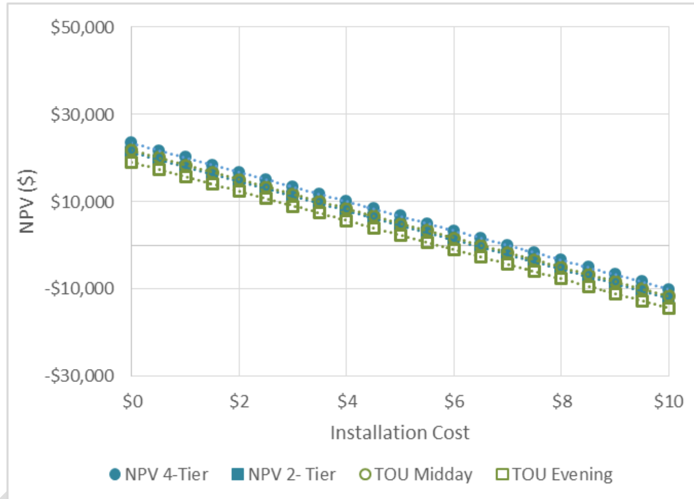

FIGURE C8: Installation Cost [$/Wdc], Fresno

Our assumed installation cost of $5 per Wdc (Watts direct current) is based on adjusting the NREL 2010 estimate of $5.50 per Wdc to expected 2012 prices[32]. Our sensitivity analysis tested an installation cost range of $0 - $10 per Wdc to model the complete possible range of costs - from self-installation to the installation surcharge incurred for difficult installations. Research shows that installations on brittle roof shingles and installations on more difficult to access roofs typically increase the price of installation by up to 25% (i.e., $6.25 per Wdc under baseline assumptions). We also wanted to test the possibility that installation costs are 50% larger than assumed (i.e., $7.5 per Wdc). This possible increase in installation costs along with the surcharge for difficult installations would result in a $10 per Wdc, which is our upper limit.

Installation cost per watt of DC generation is the most sensitive variable in every zone under every rate structure, as demonstrated in Figures C9 and C10 and in Figures C1 and C2.

A 10% or $0.50 increase in installation cost from our baseline assumption of $5 per Wdc results in an average decrease in NPV of at least 65% in every rate structure for both zones. Furthermore, an installation cost of $6 per Wdc or greater results in a negative NPV in both the Fresno and San Francisco under TOU with an evening peak. A $7 per Wdc installation cost results in a negative expected NPV in all rate structures in both Fresno and San Francisco with the exception of the 4-Tier rate in Fresno.

Reoccurring Costs

In addition to upfront costs for the panel, consumers with a PV system will face regular annual costs to upkeep the PV system. These costs are modeled with the following variables: inverter replacement frequency, inverter cost, and operation and maintenance costs per year.

[32] http://www.nrel.gov/docs/fy13osti/51644.pdf page 5, footnote 13

Inverter Replacement Frequency

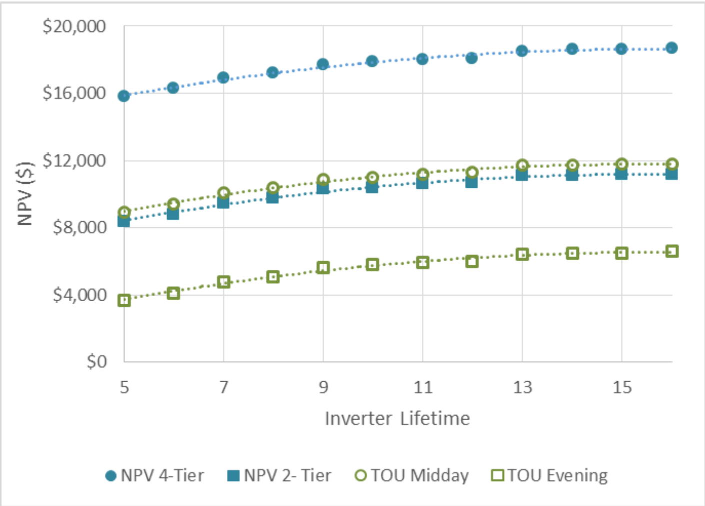

FIGURE C9: Inverter Lifetime [years], Fresno

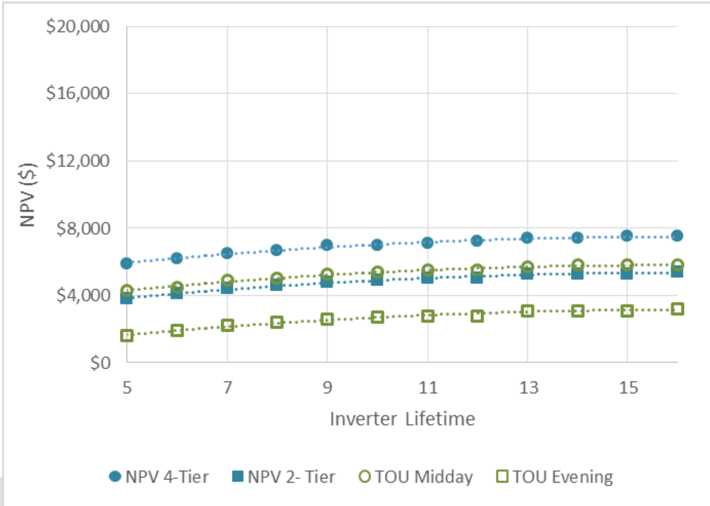

FIGURE C10: Inverter Lifetime [years], San Francisco

Many inverter manufacturers such as SunPower are offering standard 10-year warranties on inverters with options to purchase warranty extensions. Our 8-year replacement frequency baseline assumption falls within the average time to failure rate of 5-10 years[33], but is rather conservative for the majority of the suppliers' warranties in the California area. We tested the range of 5-16 years to capture the complete range of most common warranty options, 5-15 years.

As shown in figures C11 and C12, the entire tested range made little change to NPV in any of zones or rate structures.

The small change in NPV over the tested range and the similarity in slopes from one range to another are expected. The change in NPV from replacement frequencies of 5 years to 16 years is due to the difference between purchasing 4 inverters and 1 inverter over the lifetime of the PV system.

Assuming that the price of the inverter does not change over time, the maximum difference in NPV between a 5-year replacement frequency and a 16-year replacement frequency is:

Fresno: (4-1)*8.9*$220 = $5,874

San Francisco: (4-1)*4.8*$200 = $3,168

= (difference in number of inverters purchased between max and min scenario) * (PV system size in kW DC) * (inverter cost per 1kW DC)

[33] http://www.ucei.berkeley.edu/PDF/csemwp172.pdf page 10

This calculation assumes that the price per inverter does not change over time, thus it is an upper bound. If we impose the decreasing inverter cost trend (as is demonstrated in Figures C11 and C12), the 5th inverter in year 2032 would have a present value price of approximately $170/kW, thereby decreasing the upper limit.[34]

Inverter Cost

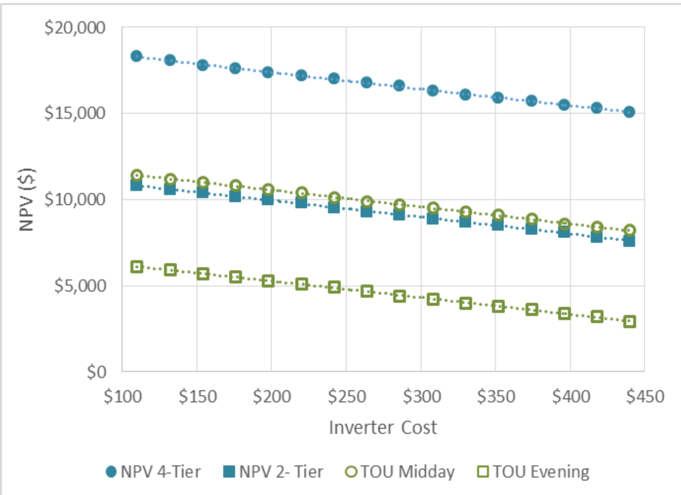

FIGURE C11: Inverter Cost, Fresno

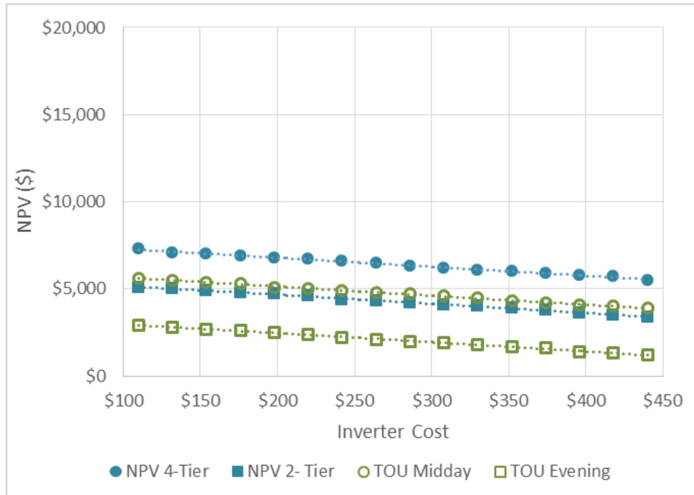

FIGURE C12: Inverter Cost, San Francisco

Similar to inverter replacement frequency, inverter costs have very little effect on NPV over the tested range of $110 - $420. We selected this range to show how little the inverter cost affects NPV even under large deviations from our baseline assumption. Our assumption of $220 per kW DC was selected to reflect inverter price data found by Greentech Media[35]. While it is unlikely that inverters will increase in price, the large range confirms that the model is not sensitive to a change in this variable.

This $110 - $420 range resulted in no negative expected NPV for any climate zones under any rate structure

The declining, linear relationship between NPV and the increasing inverter costs is as expected. The increase in inverter cost simply reduces the cash flows in every 8th year (which is the assumed inverter replacement frequency).

[34] Assuming a rate of change in inverter costs over time, the maximum costs are 4,730 and $2,527 for Fresno and San Francisco, respectively. The graphs show lower increases in NPV, given that NPV discounts future costs.

[35] http://www.greentechmedia.com/articles/read/3-Reasons-Why-Chinese-Solar-Inverters-Cost-Half-of-American-Inverters

Operation and Maintenance Costs

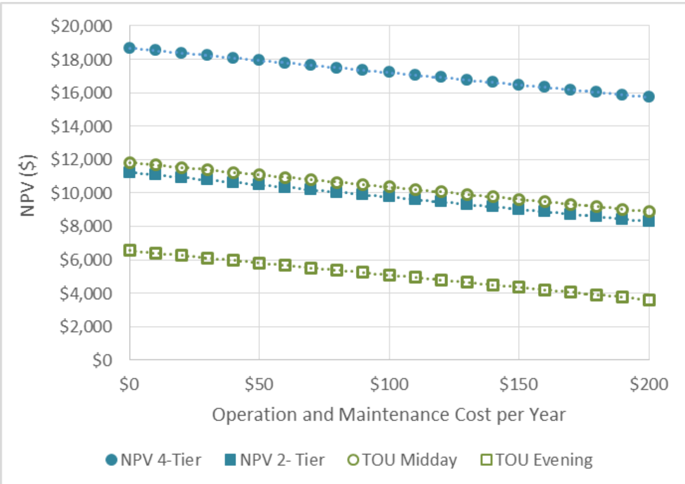

FIGURE C13: Operation and Maintenance Cost per Year, Fresno

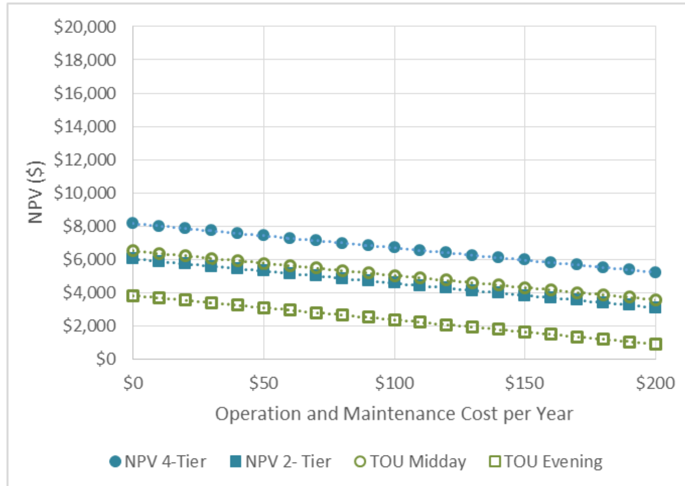

FIGURE C14: Operation and Maintenance Cost per Year, San Francisco

The operation and maintenance costs include any potential repair, replacement and inspection costs incurred per year. Most PV systems will have $0 costs for at least the first 10-years under the standard warranties that cover all system damage for 10 years.

Our baseline scenario used a conservative assumption of $100 of necessary annual operation and maintenance costs per year for the lifetime of the PV system (these costs can include things like yearly cleanings or maintenance for chewed wires). We tested a $0-$200 range of annual operation and maintenance costs to reflect a potential all-encompassing 25-year warranty and a 100% increase on our baseline assumption.

The annual operation and maintenance cost directly decreases annual cash flow per year, which results in a linear relationship between NPV and operation and maintenance cost change. However, it does not significantly affect overall system NPV under any climate zone or rate structure.

Discount Rate

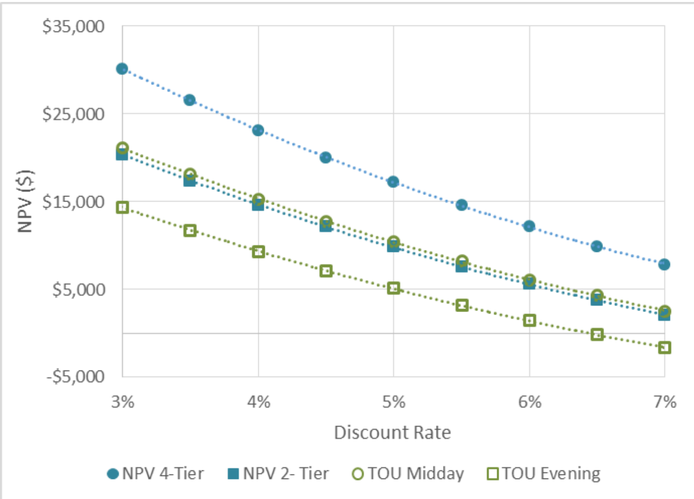

FIGURE C15: Discount Rate, Fresno

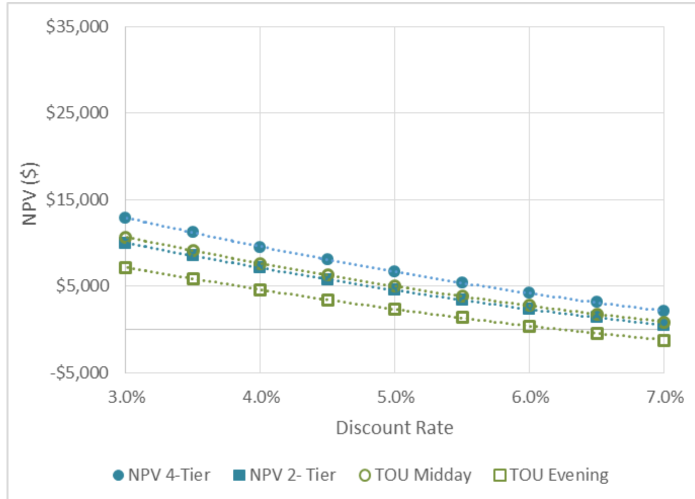

FIGURE C16: Discount Rate, San Francisco

Our results assumes a discount rate of 5%. We tested the range of 3%-7%, which are reasonable values for a household's cost of funds and may therefore reflect the household's perception of the time value of money. Adjusting the discount rate will change the relative importance of cash flows earned today versus cash flows earned in the future. A discount rate of zero places the same amount of value on $1 tomorrow relative to $1 dollar today. Similarly, a high discount rate, in our case 7%, will place more weight on the value of money today (both costs and benefits).

This means that a higher discount rate requires higher annual cash flows per year to return an equivalent NPV value. Because cash flows are lower overall in the San Francisco climate zone, this zone is more sensitive to an increase in discount rate. However, in Fresno, where the yearly cash flows are higher, even very high discount rates will result in positive NPVs under both tiered rate structures and TOU with a midday peak.

The NPV curves in figures C17 and C18 show the relationship between discount rate and NPV. As the discount rate increases, the weight of future cash flows moves towards a limit of zero. This is seen in each rate structure curve; the future cash flows are exponentially decreasing as the discount rate increases.

Electricity Price and Demand

Our model assumes that prices and demand change over time. Our baseline assumptions of how price and demand change over time are based on historic price trends and projections from the Energy Information Administration, respectively, but the rates of change are uncertain and affected by a number of exogenous factors that are difficult to predict. General economic conditions, policy decisions and technological change all affect electricity prices, and future household demand may be different from the average trend due to household composition or needs.

Electricity Price Annual Rate of Change

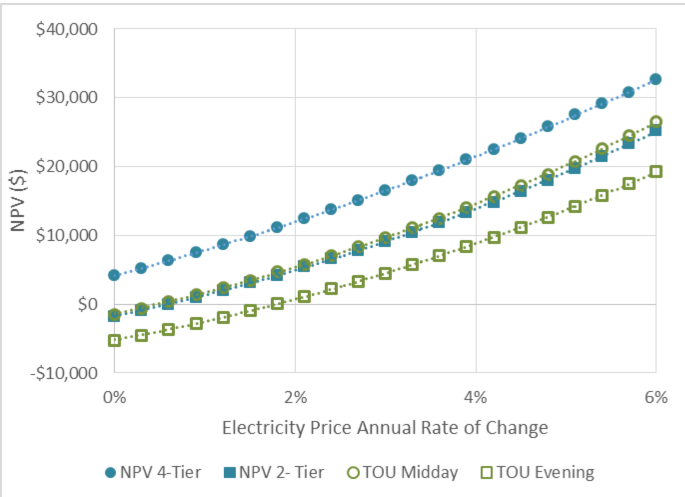

FIGURE C17: Electricity Price Annual Rate of Change, Fresno

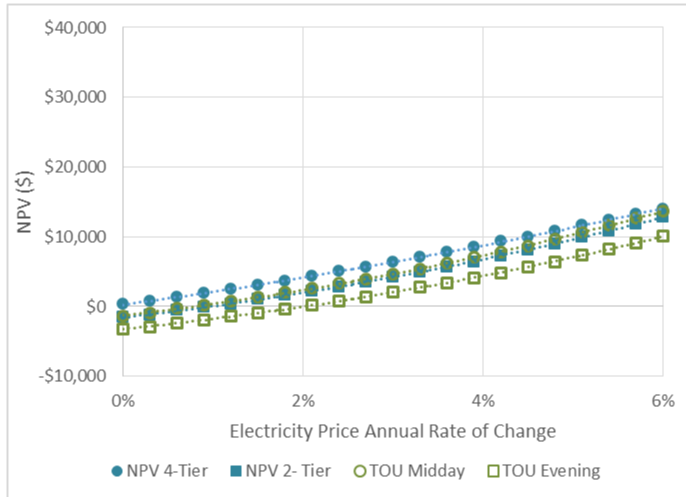

FIGURE C18: Electricity Price Annual Rate of Change, San Francisco

The electricity price annual rate of change models how the NPV will react to changes in the projected nominal rate of the electricity price increases over the lifetime of the panel. Our model assumes a 3% increase in electricity price per year for the life of the panel given the observed change in average PG&E rates over the past two decades. Here we test a range of 0% - 6%, as it is highly unlikely that electricity prices will decrease nominally and not even in real terms over the next 25 years.

In the tested range, the 2-Tier and TOU rate structures in both areas were sensitive to a change of lower than +.3% per year. In San Francisco, TOU with an evening peak is strongly sensitive; any annual electricity price change below +2.10% results in a negative expected NPV. The reason why NPV increases with increases in electricity prices is that the higher the price, the more benefits are received from generating your own PV electricity and netting off of these high prices. This result indicates that homeowners can use solar panels to hedge against likely future price increases. With very low rates of price increases, the future benefits are smaller.

Figures C19 and C20 show four very similar curves in each zone. The similarity across rate structures demonstrates that a change in electricity price over time is assumed to be the same for all tariff structures. A 1% annual increase in electricity prices will increase the value of saved energy costs by 1% per year. Though the rates are different in each tariff structure the relative increase in cash flows are the same.

Annual Electricity Demand Rate of Change

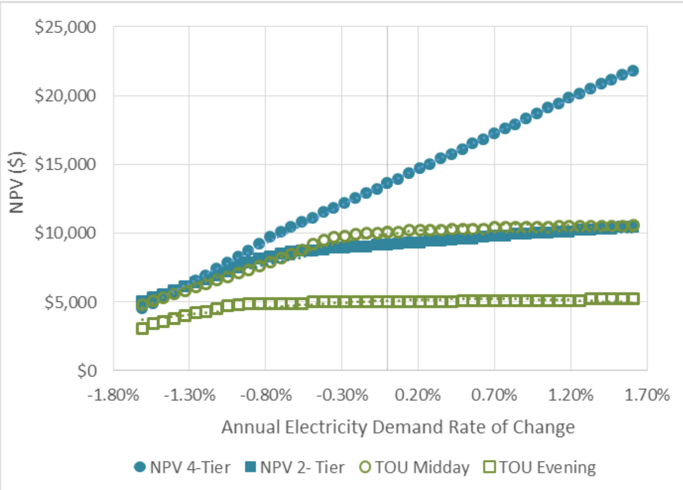

FIGURE C19: Annual Electricity Demand Rate of Change, Fresno

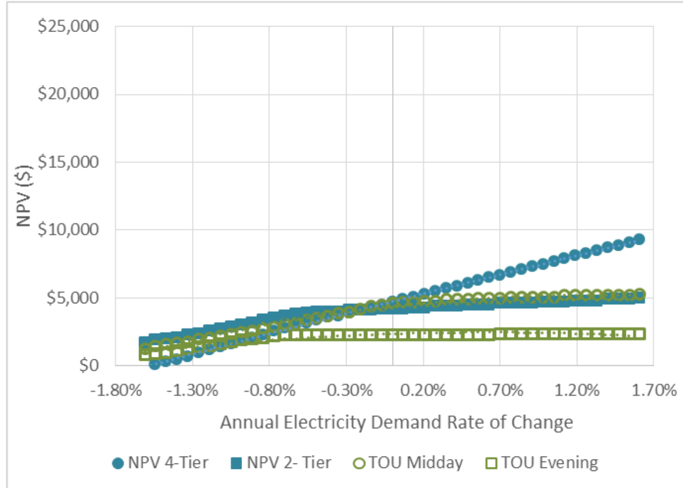

FIGURE C20: Annual Electricity Demand Rate of Change, San Francisco

The EIA expects residential electricity demand to increase by approximately 0.7% annually between 2011 and 2040, and therefore we assume this to be the rate of electricity demand increase. Our range of values starts with twice the electricity demand rate (1.6%), but also ranges into negative values, given some predictions that increasing prices, energy efficiency, and demand response will decrease consumption in the long run.

Particularly in the 4-Tiered rate case, the annual electricity demand rate of change proved to have a strong effect on the NPV. In the 4-tier case, an increase in annual electricity demand will increase the amount of electricity purchased in the 4th tier rate; this leads to an increase in the average rate per kWh, allowing the PV owner to net off of higher prices. This effect is less pronounced for the 2-tier rate. Because the 2-tier rate is both flatter and has a lower top price, increasing kWh demanded in the top tier will not have as much of an effect on the average price per kWh paid without a PV system.

The slope of the sensitivity curves in Figures C21 and C22 are steeper in the negative range of the demand rate of change variable. This is due to the fact that, in the negative range, as demand becomes smaller over time, the benefits from offsetting consumption decrease - both because the avoided retail payments are smaller but also because, for the same PV system size, generation may begin to exceed consumption. When the household generates more electricity than it consumes over the course of a full year, the excess electricity is only credited at the avoided generation rate which is significantly lower than the retail rate. Thus, a more negative future demand has a larger impact on future savings by lowering the potential to be credited at the retail rate. For the 4-tier rate structure, the slope of the curve is similar in both the positive and negative ranges, due to the fact that greater consumption levels increase the average rate significantly, generating even greater benefits from PV generation than is the case in the flatter 2-tier rate or the TOU rate.

Elasticities

The model uses two elasticities: peak substitution elasticity (to measure the consumer's ability to substitute off-peak energy for peak energy) and own-price elasticity (to measure the sensitivity to a change in the marginal price of an additional watt of energy). Because the elasticities vary over each month (see Table A1) we do not attempt to demonstrate the sensitivity of NPV to a change in each of the monthly elasticities. Instead, we alter all of the elasticities simultaneously by multiplying them by a factor which we define as "elasticity factor".

For each elasticity factor we chose a range of 0 – 3 to model a large range of flexibility and inflexibility to price.

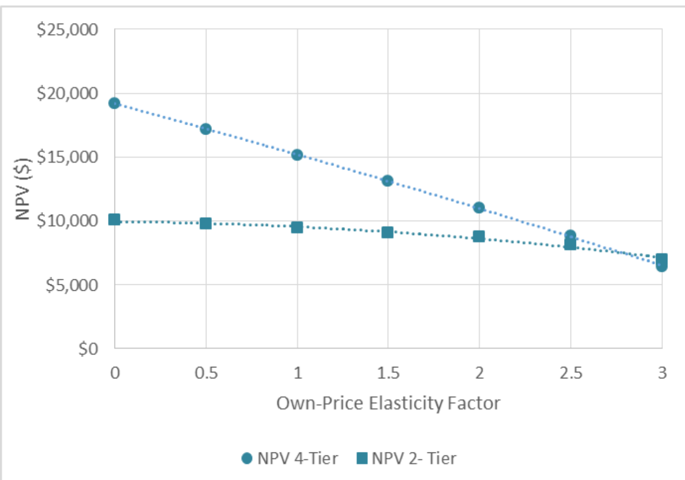

FIGURE C21: Own-Price Elasticity, Fresno

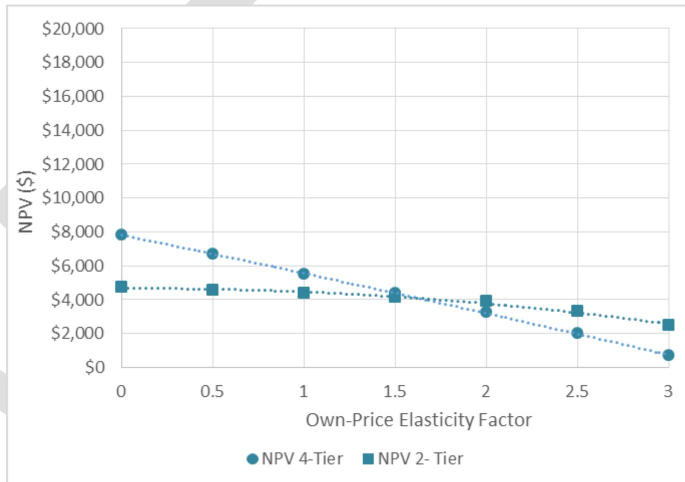

FIGURE C22: Own-Price Elasticity, San Francisco

The own-price elasticity is important when we apply a change in demand or a change in prices, but only for the tiered rate structures. This is because Ito (2014) has demonstrated that consumers on tiered rates respond to changes in the average electricity price, but consumers on TOU rates respond to marginal prices. Under NEM with tiered rates, a PV system reduces the net consumption level, allowing the household to fall into a lower tier - which effectively lowers their average electricity rate and thereby potentially stimulates increased electricity use. The own-price elasticity determines how much more consumption will occur with a decreased rate – the larger (more negative) the elasticity, the larger the increase in electricity use. Since TOU customers do not see the same impact on their average electricity rate from installing a PV system and therefore are not assumed to adjust their electricity use after investment, we only present the tiered rate structures in these graphs.

As seen in Figures C23 and C24, NPV is fairly insensitive to a change in own-price elasticity under the 2-tiered tariff but more so under the 4-tiered tariff. Under the 4-tiered tariff, installing a PV system will cause a larger decrease in the average price. This will cause the household to increase consumption more than they would under the flatter 2-tiered tariff given the same own-price elasticity. The larger the own-price elasticity, the larger the increase in electricity use after having installed a PV system, and therefore, the smaller the financial savings from the PV system.

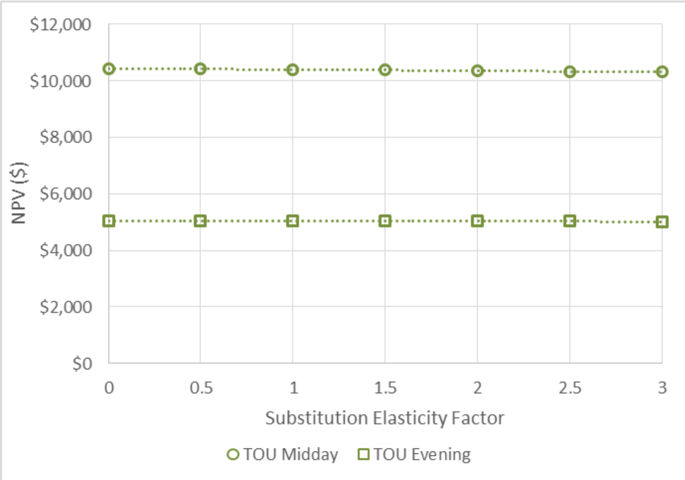

FIGURE C23: Peak Substitution Elasticity, Fresno

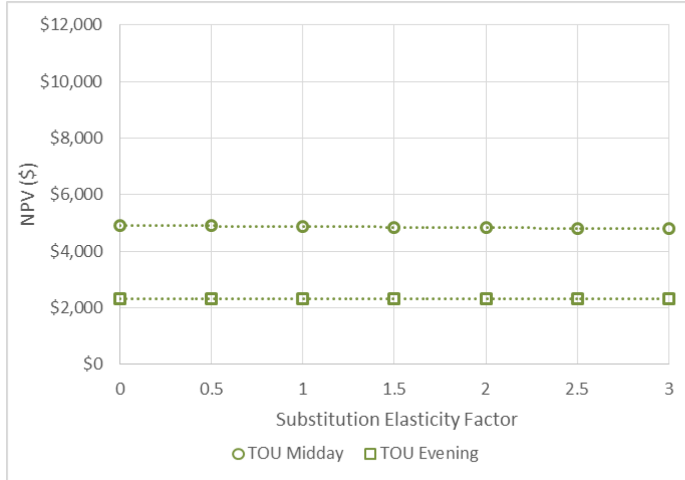

FIGURE C24: Peak Substitution Elasticity, San Francisco

For the substitution elasticities, we only present the TOU rate structures, because these elasticities only affect how consumers substitute between peak and off-peak times. However, although TOU customers are assumed to change how they distribute their electricity use across peak and off-peak times with a switch to TOU rates from tiered rates, they are not assumed to change their electricity use patterns *after* having invested in a PV system. We therefore would not expect to see an impact on the NPVs from changes in the substitution elasticities. As expected, Figures C25 and C26 demonstrate that large increases in the (absolute value of the) substitution elasticities do not appear to have a noticeable effect on NPV.