Cost Competitiveness of Residential Solar PV: The Impact of Net Metering Restrictions

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Abstract

The policy of net metering allows operators of residential- and commercial solar PV systems to sell surplus electricity back to their utility at the going retail rate. This policy has recently been criticized on the grounds that it provides a subsidy for residential and commercial solar installations, a subsidy that is paid for by all ratepayers. In response, public utility commissions have begun to take up this regulatory issue. This paper presents a theoretical and empirical analysis of the effects of net metering restrictions. We examine the impact that overage tariffs (OT) will have on the size of future residential PV investments. Overage tariffs credit electricity generated by the solar system, but not consumed by the household and thus transferred back to the utility, at a rate below the going retail electricity rate. Our calculations focus on three representative locations in the states of California, Nevada and Hawaii. We find that if overage electricity is credited at some rate set at or above the levelized cost of electricity (LCOE), there would be sufficient incentives for investors in residential solar PV to continue in the current mode of solar rooftop installations, even though the profitability of these investments might be reduced substantially. At the same time, we find that the LCOE is a tipping point insofar as overage tariffs set below that level would have a sharply negative effect on the individual size and overall volume of new rooftop installations.

Keywords: Solar PV, Net Metering, Levelized Cost, Time of Use Pricing

1 Introduction

Solar photovoltaic installations have been deployed globally at a rapid pace in recent years. In the U.S., growth has been particularly steep for the residential segment.[1] The economic viability of solar photovoltaics (PV) has been aided significantly by the decline in systems prices for solar PV modules, inverters and so-called balance of system (BOS) costs.[2] Public policy has also played a crucial role in shaping the economics of solar PV. In addition to various renewable portfolio standards at the state level, federal tax policy in the form of the federal investment tax credit (ITC) has provided a substantial boost to solar PV.[3] Finally, the residential and commercial segments of the industry have benefited from a policy of *net metering* adopted by many jurisdictions in the U.S. Accordingly, surplus electricity generated by the solar system at a particular point in time can be sold back to the electricity service provider (utility) at the same retail rate that the customer would be charged for electricity purchases.

As the volume of residential solar installations has grown rapidly, utilities and other stakeholders have become vocal that the policy of net metering provides a subsidy to solar power which is paid for by the entire population of ratepayers. These advocates point out that net metering forces the utility to buy surplus electricity at the going retail rate for electricity, though it could procure the same power at the lower wholesale rate (Darghouth, Barbose, and Wiser, 2011; McHenry, 2012). Public utility commissions have begun to examine these issues and, in some jurisdictions, have limited the policy of net metering. This paper develops a framework and a methodology for predicting the impact of net metering restrictions on the deployment of residential solar systems. In essence, we examine the sensitivity of these investments in response to *overage tariffs* (OT) that credit electricity generated by the solar system, but not consumed by the household, at a rate below the going retail electricity rate.[4]

We examine the impact of net metering restrictions through the lens of an investor

[1] In each of the years 2012–2015 the annual growth in residential solar exceeded 50%, with annual installations reaching approximately 2.1 GW in 2015 (SEIA, 2016).

[2] BOS costs include: inverters, wiring, racking and mounts, structural/foundations, AC interconnection, engineering/design, labor (general and electrical), as well as general and administrative expenses, including profit margins for the suppliers.

[3] The 30% federal Investment Tax Credit (ITC) was scheduled to be stepped down to 10% in early 2017, but late in 2015 Congress decided on gradual "sliding scale" extension through 2024 (U.S. Congress, Rules Committee Print 114-39, Division P, December 15, 2015).

[4] Several countries around the world, most notable Germany, have set feed-in-tariffs *above* the going retail rate in order to promote the deployment of residential and commercial solar PV.

evaluating the profitability of rooftop solar PV systems. Specifically, we consider a developer who installs and owns the solar system. Our research approach complements earlier work in this area. Some studies assess the impact of net metering from the perspective of the incumbent utility; for example see Darghouth, Barbose, and Wiser (2011), Cai et al. (2013) and Graffy (2014). Others address the influence of alternative rate structures on distributed PV deployment generally (e.g. Darghouth et al. (2016)), or focus on mitigating the cost of net metering programs (Satchwell, Mills, and Barbose, 2015). Finally, some authors have examined net metering and distributed generation from the perspective of transparency and the "intrinsic value" provided by distributed generation (Barraco, 2014). In contrast, we examine to what extent restrictions on net metering impinge the profitability of rooftop solar systems and possibly curtail the investment incentives for developers.

An investor/developer will typically enter into a contract with the homeowner specifying either a power purchasing or a leasing arrangement. As part of this contractual arrangement the homeowner essentially earns a "rooftop rental fee" that must be sufficient to make the rooftop available for the solar installation. Holding the compensation to the homeowner constant, the question then becomes how investors will respond to the adoption of overage tariffs that credit electricity sold back to the utility at a rate below the retail rate.

In a regulatory environment where net metering applies and the homeowner is charged a time-invariant, flat rate for electricity, an investment in a solar PV system will have a positive net present value (NPV) if and only if the retail rate exceeds the *Levelized Cost of Electricity* (LCOE). This life-cycle cost measure is calculated on a per kilowatt-hour (kWh) basis. It aggregates all cost components of a power generation facility, including upfront capital expenditures, operating costs, applicable taxes, and the rooftop rental fees paid to the homeowner, so as to ensure that investors earn an adequate return on the project.[5] Furthermore, the NPV of the project is proportional to the difference between the retail rate and the LCOE, with the factor of proportionality being linear in the size of the solar facility. For a regulatory environment that sets an overage tariff below the retail rate, Figures 1 and 2 illustrate the attendant tradeoff.[6]

[5]Earlier literature has argued that a levelized cost analysis may be inadequate in connection with intermittent power sources like solar PV; see, for instance, (Joskow, 2011a,b), Borenstein (2008) and Reichelstein and Sahoo (2015). The key consideration in these studies is that, in addition to an intermittent power generation pattern, the value of the electricity generated is also dependent on the time of day and/or the season.

[6]Figures are based on data provided by NREL (2016b), NREL (2010) and NREL (2015a). More detail is provided in Section 3.

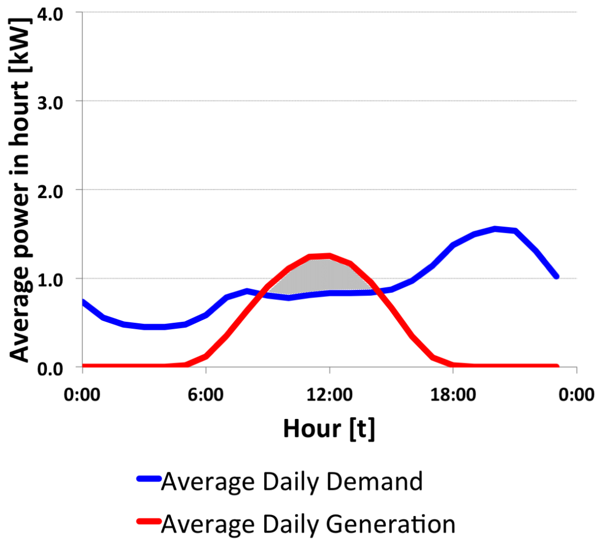

Figure 1: Majority of generation consumed by load, avoiding cost of retail rate.

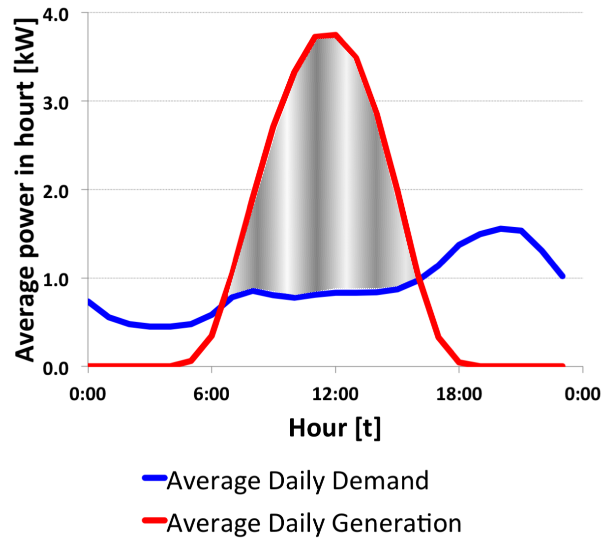

Figure 2: Minority of generation consumed by load; power exports valued at overage tariff.

The blue curve in Figures 1 and 2 represents the average electricity consumption of a typical household in Los Angeles, California for one 24-hour cycle. This load profile is viewed as exogenous and constant in our analysis. The red curve in Figure 1 represents the generation profile of a relatively small residential solar installation. Most of the electricity generated will be valued at the going retail rate, as household consumption exceeds production. With net metering restrictions, it is only the energy represented by the shaded area in Figure 1 (the overage electricity) that will be valued at the overage tariff (OT). By comparison, Figure 2 depicts a relatively large solar installation and now most of the electricity generated (shaded area) is valued at the overage tariff. On an hourly basis, revenues from a solar installation can effectively be represented as a convex combination of the retail electricity rate and the OT, with the weight on the overage tariff increasing in the size of the solar installation. From an investor perspective, the resulting tradeoff is akin to that of a firm with pricing power in its product market: higher sales volume (a larger solar system) can be achieved only at the expense of lower margins per unit of output sold.

We apply our model framework to three specific locations: Los Angeles (California), Las Vegas (Nevada) and Honolulu (Hawaii). All of these states have experienced significant deployments of solar power in recent years, yet their authorities having jurisdiction over such matters have taken rather different paths with regard to the policy of net metering. Subject to certain surcharges for owners of residential solar systems, California has basically re-affirmed its policy of net metering, while Nevada has put forward a schedule that will gradually lower the OT down to the wholesale value of electricity.[7] In contrast, Hawaii has opted for an intermediate solution that sets the OT in between the wholesale and the retail rate in that state.

With full net metering, the size of residential solar PV systems is generally limited by two factors: the physical constraints on rooftop size and an aggregate surplus constraint which specifies that if the annual electricity generated by the solar PV system exceeds the total annual electricity consumption by the household, the resulting "net energy surplus" is credited at a substantially lower rate.[8] We find that the latter constraint effectively determines the optimal (NPV maximizing) rooftop installation size. As a consequence, modest restrictions on net metering in the form of overage tariffs for *any* kilowatt hours sold back to the utility will not have an immediate impact on the optimal size of residential solar systems, yet such restrictions will, of course, affect the profitability of the investment.

The central findings of our study are that regulators have considerable leeway in imposing net metering restrictions, without causing tangible reductions in the predicted size of new solar rooftop installations. While investors would earn lower returns, an overage tariff set at or above the levelized cost of residential solar electricity would not compromise the incentive to invest in solar PV installations that are of the same size as those resulting under full net metering. At the same time, we conclude that the LCOE is effectively a *tipping point* for the OT. For California, Nevada and Hawaii, our model calculations indicate that new residential solar installations would be curtailed sharply in size if the OT were set more than 10% below the LCOE.[9]

The three states that are the focus of our analysis offer residential ratepayers Time-of-Use (ToU) pricing as an alternative to traditional time-invariant electricity pricing. Furthermore, California intends to make ToU pricing mandatory beginning in 2019. We extend our analysis

[7]In California, homeowners with solar PV installations within load-serving territories subject to CPUC oversight will generally pay a "non-bypassable" 2–3 cents per kWh surcharge on electricity consumed from the grid.

[8]In California, any net energy surplus is credited at wholesale rates (AB 920 in California, and LADWP Solar Program for Los Angeles specifically). In Hawaii and Nevada, such net energy surplus is deemed to have zero value (Docket 2014-0192 and Docket 15-07041 respectively).

[9]Consistent with this prediction, we note that solar developers, including SolarCity and Sunrun, announced in early 2016 that they would withdraw from operations in the state of Nevada once that state's Public Utilities Commission decided that in the future the credit for any overage electricity from solar rooftops would be reduced by approximately 18% (to a level 11% below our calculations for LCOE) in 2016 from the previous year and continue to decline to the wholesale rate in a step-wise manner over the subsequent 12 years.

by assuming that the ToU schedules currently being offered will be adopted. Furthermore, we assume that the OT with ToU pricing would entail proportionally lower rates at each point in time, yet the intertemporal variation in prices would be the same as for the ToU retail rate. For California and Hawaii, our findings are essentially unchanged for the ToU pricing regime. In Nevada, the ToU schedule currently offered as an alternative to time-invariant pricing would render residential solar PV altogether uncompetitive.[10]

The remainder of the paper is organized as follows. Section 2 presents the model framework for identifying the optimal size of residential installations, if electricity exports are credited at some OT rate and are subject to the aggregate surplus constraint. We develop the model for both time-invariant and time-of-use pricing. In Section 3, we numerically evaluate the implications of an OT set either above or below the LCOE. Section 4 provides a discussion of our results. We conclude in Section 5 and provide supplementary materials in Appendices A through G. Finally, we provide the details of the underlying cost model within the *Residential Net Metering Cost Analysis* as part of the *Supplementary Information*.

2 Model Framework

Our model takes the perspective of an investor who seeks to optimize the size of a solar PV rooftop installation in response to retail prices for electricity and possible restrictions on net metering. It will be convenient to think of the investor as the developer who installs and owns the PV system. Prior to the installation, the developer will typically have entered into a long-term contract with the homeowner specifying either a leasing or power purchasing agreement (PPA). The difference between the retail rate and the PPA rate that the homeowner pays to the developer represents a "rooftop rental fee" that induces the homeowner to make his/her roof available.

Suppose first that retail rates are time-invariant, that is, the household pays a fixed retail rate independent of the time of use, and there are no restrictions on net metering. An investor will then find a particular solar installation profitable according to the net present value (NPV) criterion if and only if the retail electricity rate exceeds the Levelized Cost of Electricity (LCOE); see, for instance, Comello and Reichelstein (2016). The LCOE identifies

[10] This finding reflects the confluence of several factors: (i) a small number of summer months (i.e., four months) peak prices apply, (ii) peak-prices tend not to be aligned with the PV generation pattern and (iii) the relatively low off-peak prices charged during all hours of the winter months.

an average unit cost per kWh that aggregates the life-cycle cost of all assets and resources associated with the electricity generation facility. Following the notation in Comello and Reichelstein (2016), the LCOE can be expressed as:

$$LCOE = w + f + c \cdot \Delta, \tag{1}$$

where w represents the time-averaged variable cost per kWh, f captures the corresponding fixed operating costs and c represents the levelized installation cost of the facility. Finally, Δ is a tax factor that incorporates the impact of income taxes, depreciation tax shields and investment tax credits. For solar photovoltaic power, the only tangible component of variable operating cost will be the rental rooftop fee that the investor pays to the residential owner. We represent this cost as a constant dollar charge to be paid for each kWh that the system generates.

The investment and operating costs associated with a solar PV facility are assumed to scale proportionally with its peak power capacity. Ignoring tax considerations at first, the life-cycle cost of a solar facility capable of generating one kilowatt of peak power is determined by the following parameters:

- SP : system price (installation cost in \$ per kW),[11]
- T : useful life of the output generating facility (in years),
- $\gamma \equiv \frac{1}{1+r}$: discount factor based on cost of capital r (scalar),
- f_i : fixed operating cost in year i (in \$ per kW),
- w_i : unit variable cost in year i (in \$ per kWh),
- $CF(t)$: capacity factor at time t in the first year (scalar).

In each year of operation, the system is assumed to generate power continuously for 8,760 hours (the total number of hours in a year).[12] As introduced here, the LCOE concept ignores

[11]The system price associated with a solar rooftop installation is arguably subject to some scale economies such that SP is decreasing in the size of the system. However, these scale economies are rather small for the range of alternative system sizes considered in our analysis (Barbose et al., 2016). We revisit this point in our discussion in Section 4 below.

[12]Solar PV modules are subject to a small degradation factor, implying that the power produced in any given year is about .997 of the power produced in the previous year. For reasons of model parsimony, we ignore the degradation factor in our analysis, though at the end of this section we discuss how our results would be affected if this factor were to be included in the model.

intertemporal variations in the capacity available across time and considers only the average annual capacity factor, CF, given by:

$$CF = \frac{1}{m} \cdot \int_0^m CF(t)dt, \tag{2}$$

since there are $m \equiv 8,760$ hours in a year. To obtain the levelized capacity cost per kWh, the initial system price is divided by the discounted total number of kilowatt hours that can be obtained from an installation of one kilowatt of power:

$$c = \frac{SP}{m \cdot CF \cdot A}. \tag{3}$$

Here $A = \sum_{i=1}^{T} \gamma^i$ denotes the annuity factor of \$1 paid over T years, given an interest rate of r. We refer to the denominator in (3) as the *aggregate output* (life-time) per kW of peak power installed. To obtain the levelized operating costs per kWh for fixed and variable operating costs, the present value of all costs is divided by the aggregate output. Thus:

$$w \equiv \frac{\sum_{i=1}^{T} w_i \cdot \gamma^i \cdot m \cdot CF}{m \cdot CF \cdot A}, \tag{4}$$

and

$$f \equiv \frac{\sum_{i=1}^{T} f_i \cdot \gamma^i}{m \cdot CF \cdot A}. \tag{5}$$

The final component of the LCOE is the tax factor, Δ. The financial impact of corporate income taxes is determined by investment tax credits, depreciation tax shields, and debt tax shields. Since our calculations calibrate the cost of capital as the weighted average cost of capital (WACC), the debt tax shield is already accounted for.[13] Finally, the depreciation tax shield is determined jointly by the effective corporate income tax rate and the allowable depreciation schedule. The following notation formally introduces these variables:

[13]It can be verified that if the debt-equity ratio remains constant, debt holders will exactly break even on their investments, if the average sales price of electricity is equal to the LCOE calculated with a cost of capital equal to the the WACC.

- ITC : investment tax credit (in %),
- α : effective corporate income tax rate (in %),
- d_t: allowable tax depreciation charge in year t (in %),
- δ: "capitalization discount", equal to 0.5 under current federal tax rules,[14]
- λ: mark-up factor on system price ($\lambda > 1$).

The useful life of a solar facility for tax purposes is usually shorter than its economic useful life, T. Accordingly, $d_i = 0$ in those years. For an investor/developer the system price (SP) represents the acquisition cost of the system which is generally below the fair market value (FMV) as assessed by independent appraisers. This difference arises because the appraiser may apply an income approach, rather than a cost approach, to valuing the solar energy system for tax purposes.[15] Thus, $FMV \equiv \lambda \cdot SP$. Consistent with the derivation in Comello and Reichelstein (2016), the tax factor can now be represented as:

$$\Delta = \frac{1 - \lambda \cdot ITC - \alpha \cdot \lambda(1 - \delta \cdot i) \cdot \sum_{i=0}^{T} d_i \cdot \gamma^i}{1 - \alpha}. \tag{6}$$

For solar power installations, the current U.S. federal tax code not only allows for a 30% Investment Tax Credit, but also for a 50% bonus depreciation in the year of installation (d_0) and a five-year accelerated depreciation schedule. The effect of these tax subsidies is a substantially lower tax factor. To illustrate, for a traditional fossil fuel generation facility, the tax factor would typically be around 1.3, while in our calculations in Section 3 the tax factor drops to about 0.4 (Table A.2 in the Appendix). Since the capacity related costs, c, are the dominant LCOE component in solar installations, U.S. federal tax rules have a first-order effect on the cost competitiveness of solar systems. Appendix B demonstrates formally that, given net metering, an investor will break-even in terms of discounted cash flows if the retail rate of electricity per kWh, p is equal to the LCOE.

[14]The tax code stipulates that if an investor claims a 30% ITC, then for depreciation purposes only 85% (= 1 - 0.3 $\cdot$ 0.5) of the system price can be capitalized for depreciation purposes.

[15]See SolarCity (2014) for further discussion on this point.

2.1 Time-Invariant Pricing

This subsection examines a setting where households pay a retail rate for electricity, that is independent of the time of use.[16] We denote this rate by p. Let $\bar{k}$ denote the largest possible peak power capacity that the household could install given the physical limitations of its rooftop. Our analysis maintains the assumption that electricity consumption by the household is unaffected by the decision to invest in a solar PV system. However, we do allow for consumption to be positively correlated with the size of the home and correspondingly the size of the rooftop, $\bar{k}$. Let $\beta(\bar{k}) \cdot L(t)$ denote the *load profile* for a household with rooftop size $\bar{k}$, where $\beta(\cdot)$ is some increasing function. Thus $\beta(\bar{k}) \cdot L(t)$ represents the rate at which power is consumed at time t, for $0 \leq t \leq m$.

Net metering restrictions could be imposed insofar as electricity sold back at any point in time to the electricity service provider (utility) is credited only an amount of p^o per kWh. We refer to p^o as the *Overage Tariff (OT)*, noting that a tariff of $p^o = p$ corresponds to net metering. In addition to such net metering restrictions, an investor will face an *aggregate surplus constraint*, which specifies that the aggregate amount of electricity sold back to the energy service provider exceeding the total annual consumption, i.e., the net energy surplus, will be credited only at some lower rate, denoted by p^-. In California, for instance, p^- is given by the average wholesale rate. We represent the aggregate surplus constraint as a "penalty" insofar as excess energy would no longer be credited at the OT rate p^o but rather at p^-. The aggregate overage penalty can then be represented as:

$$D(k|\bar{k}) = \max\{0, m \cdot CF \cdot k - L(\bar{k})\} \cdot (p^o - p^-), \tag{7}$$

where $L(\bar{k}) \equiv \int_0^m \beta(\bar{k}) \cdot L(t)\, dt$. Thus, there is effectively a penalty in any given year only if the solar installation involves a capacity size that exceeds the *threshold size* $\hat{k}(\bar{k})$, given as the solution to the equation $m \cdot CF \cdot \hat{k}(\bar{k}) = L(\bar{k})$.[17]

For an installation of k kW of peak power, with $k \leq \hat{k}(\bar{k})$, the effective revenue obtained from the solar PV system at time t in year i becomes:

[16] In some locations, consumers are charged according to a so-called "tariff-block" structure. The average retail rate then varies with overall consumption, though the rates are unaffected by the time when electricity is consumed. We further discuss tariff blocks in Section 3 below.

[17] In the following discussion, we assume implicitly that $\hat{k}(\bar{k}) \leq \bar{k}$. Otherwise the effective threshold is given by $\bar{k}$, the physical constraint on rooftop size.

$$Rev(t|k,\bar{k}) = p^o \cdot CF(t) \cdot k + (p - p^o) \cdot \min\{\beta(\bar{k}) \cdot L(t), CF(t) \cdot k\}. \tag{8}$$

The expression in (8) reflects that any electricity generated by the solar PV system can be sold at the overage tariff p^o. In addition, the kilowatt hours generated at times when the household electricity consumption is at least as large as the amount generated by the solar PV system, are worth the full avoided cost of the retail rate, that is, $p = p^o + (p - p^o)$. Given a fixed average daily demand (load profile), any generation that exceeds demand in a given hour is sold at p^o per kWh.

Revenue at any point in time is weakly increasing in the overage tariff. It will be convenient to denote:

$$z(t|k,\bar{k}) = \min\{\beta(\bar{k}) \cdot L(t), CF(t) \cdot k\}, \tag{9}$$

and

$$z(k|\bar{k}) \equiv \frac{1}{m \cdot CF \cdot k} \cdot \int_0^m z(t|k,\bar{k})\, dt. \tag{10}$$

We interpret $z(k|\bar{k})$ as the percentage of all kilowatt hours generated by the solar system that is eligible for the *price premium*, $p - p^o$. In particular $z(k|\bar{k}) \in [0, 1]$. Furthermore, it is readily seen that the function $z(\cdot|\bar{k})$ is decreasing in k. Figures 1 and 2 in Section 1 suggest that for sufficiently small installations, any restrictions on net metering would have no impact provided the household always consumes a minimal amount of electricity and therefore there are effectively no electricity exports. Formally, suppose that for some arbitrarily small $\underline{L}$, it is true that $\beta(\bar{k}) \cdot L(t) \geq \underline{L} > 0$ for all $t \in [0, m]$, then $z(t|k,\bar{k}) = CF(t) \cdot k$ for all t, provided k is sufficiently small. As a consequence, $z(k|\bar{k}) \equiv 1$ for small values of k.

It will be convenient to introduce the concept of the *Hourly Contribution Margin* (HCM) associated with a solar system that has a peak power capacity of k kW. HCM reflects the *average* revenue, less the average cost per kWh. As argued above, the average cost is given by the LCOE, while the average revenue is determined jointly by the load profile, the retail price and the OT. Specifically:

$$HCM(k|p, p^o, \bar{k}) \equiv z(k|\bar{k}) \cdot p + (1 - z(k|\bar{k})) \cdot p^o - LCOE. \tag{11}$$

With net metering, the HCM reduces to $p - LCOE$ because $z(k|\bar{k}) = 1$ in that case. With restrictions on net metering, that is, when $p > p^o$, the hourly contribution margin $HCM(\cdot)$ is decreasing in the size of the installation, k. We refer to an installation of size k as *cost competitive* if the investment has a positive net present value.

Proposition 1 *Given a load profile, $\beta(\bar{k}) \cdot L(t)$, retail price, p, and OT, p^o, a solar installation of k kW of peak capacity, with $k \leq \hat{k}(\bar{k})$, is cost competitive if and only if:*

$$HCM(k|p, p^o, \bar{k}) \geq 0. \tag{12}$$

The proof of Proposition 1 in Appendix B shows that for a solar system of size k below the threshold size $\hat{k}(\bar{k})$, the overall net present value of an investment in a facility that delivers k kW of peak power is proportional to the hourly contribution margin, with the proportionality factor given by k times the aggregate output factor in the denominator of equation (3). For a solar PV system of arbitrary size k, the NPV expression becomes:

$$NPV(k|\bar{k}) = (1 - \alpha) \cdot A \cdot [m \cdot CF \cdot HCM(k|p, p^o) \cdot k - D(k|\bar{k})]. \tag{13}$$

For most residential solar installations the upper bound on the available size due to rooftop space limitations, $\bar{k}$, will be less than 15 kW (Barbose et al., 2016). An immediate question then becomes whether an investor would seek to install a system larger than the threshold size, $\hat{k}(\bar{k})$, if full net metering applies.

Proposition 2 *Suppose that $LCOE > p^-$ and net metering applies, that is $p = p^o$. The optimal size of the solar PV system is then equal to the threshold size, $\hat{k}(\bar{k})$.*

The simple insight underlying Proposition 2 is that the marginal NPV per additional kW in the size of the solar system is given by $p - LCOE$ for $k < \hat{k}(\bar{k})$, yet the marginal NPV is $p - LCOE - (p - p^-) < 0$ for $k > \hat{k}(\bar{k})$.

Proposition 2 illustrates clearly how net metering is qualitatively different from a feed-in tariff set equal to the retail rate, i.e., $p^o = p$.[18] Under a feed-in tariff, as instituted by several European countries, *all* electricity sold back to the grid is credited at the rate p^o. Under net metering, surplus electricity is credited at the retail rate $p = p^o$, subject to the aggregate

[18] We are grateful to Jan Ossenbrink and to an anonymous reviewer for asking us to elaborate on the differences between these two policy instruments.

surplus constraint that there can be no excess net energy generation annually.[19] Proposition 2 shows that with net metering, subject to the aggregate surplus constraint, an investor will prefer a solar PV system of the threshold size $\hat{k}(\bar{k})$, while with a feed-in tariff equal to $p = p^o$, the same household would prefer the largest physically possible installation, that is, $\bar{k}$.

The natural question then becomes whether an optimally sized solar system is below the threshold level $\hat{k}(\bar{k})$ if, in addition to the aggregate constraint, any overage is credited at the overage tariff, p^o, with $p^o < p$. To that end, it will be useful to introduce the function $z^-(k|\bar{k}) \equiv z(k|\bar{k}) + z'(k|\bar{k}) \cdot k$.[20] We note that $z^-(\cdot|\bar{k})$ is effectively a "marginal revenue" function: it captures the marginal impact of higher output (system size) on the overall "revenue", that is, the output that is valued at the premium value, $p - p^o$.

Proposition 3 *Suppose that $z^-(k|\bar{k}) > 0$ for all $k < \hat{k}(\bar{k})$ and $z^-(k|\bar{k}) < \frac{LCOE-p^-}{p-LCOE}$ for all $k > \hat{k}(\bar{k})$. The optimal size of the solar PV system is then equal to the threshold size, $\hat{k}(\bar{k})$, provided $p \geq p^o \geq LCOE$.*

The condition on $z^-(\cdot|k)$ will be met in the three scenarios we analyze in the following sections because for those applications $z^-(\cdot|k) > 0$, and both $z^-(\cdot|k) < 1$ and $LCOE - p^- > p - LCOE$. Thus we effectively predict that the optimal size of residential solar systems is "sticky" insofar as any overage tariff, p^o that satisfies $LCOE \leq p^o \leq p$ will result in the same system size, that is, $\hat{k}(\bar{k})$. For a lower overage tariff, the investor may prefer to remain below the threshold level and opt for an installation of size k^* kW that satisfies the first-order condition for the maximization problem in (13):

$$z^-(k^*|\bar{k}) = \frac{LCOE - p^o}{p - p^o}. \tag{14}$$

This first-order condition reflects that for installations smaller than the threshold level, there is no aggregate overage penalty. Consistent with the findings in Propositions 2 and 3, we note that there is no interior optimum on the interval $[0, \hat{k}(\bar{k})]$ if (i) $p \geq p^o \geq LCOE$ and (ii) the function $z^-(\cdot)$ that emerges for a particular location is positive for all k in the feasible range of residential solar installations, say up to a $\bar{k} \leq 15$ kW. The central questions in our empirical analysis below therefore are whether (i) $z^-(\cdot)$ is indeed positive on the normal size range for residential solar systems and (ii) how quickly this function declines in k so as to

[19] Differences between these two policy instruments have also been examined in Poullikkas (2013) and Dusonchet and Telaretti (2015).

[20] Since the function $z(\cdot|\bar{k})$ is monotonically decreasing, it is almost everywhere differentiable.

meet the first-order condition in (14) as p^o is reduced below LCOE.

2.2 Time of Use Pricing

In some U.S. states, such as California, Hawaii and Nevada, residential users currently have the option of being charged according to a Time of Use pricing (ToU) schedule. Furthermore, California intends to make time of use charges the default by 2019. To reflect this structure in our modeling framework, we denote the ToU pricing schedule by $p(t) \equiv p \cdot \mu(t)$ with

$$\int_0^m \mu(t)\, dt = m. \tag{15}$$

Thus, $\mu(t)$ represents the intertemporal variation from the average retail price. Similarly, the OT may credit the solar facility at a time dependent rate $p^o(t)$ with $p^o(t) \equiv p^o \cdot \mu(t)$. Thus, we assume initially that the OT may have a lower average value ($p^o < p$), but the two pricing schedules have the same intertemporal variation.[21] With time of use pricing, the above expression for revenue in (8) at any given point in time t becomes:

$$Rev_i(t|k) = p^o(t) \cdot CF(t) \cdot k + (p(t) - p^o(t)) \cdot z(t|k, \bar{k}), \tag{16}$$

with $z(t|k, \bar{k}) = \min\{\beta(\bar{k}) \cdot L(t), CF(t) \cdot k\}$. The condition that the average electricity price must exceed the LCOE in order for an investment in a solar facility to be profitable needs to be modified with ToU pricing. Specifically, an NPV analysis must account for the fact that electricity rates may be relatively high at times of the day when solar systems deliver a relatively large part of their peak power. Following Reichelstein and Sahoo (2015), the presence of such synergies can be captured effectively by the following *Co-Variation* coefficient:

$$\Gamma = \frac{1}{m} \int_0^m \epsilon(t) \cdot \mu(t)\, dt, \tag{17}$$

where, by definition, $CF(t) = CF \cdot \epsilon(t)$, so that $\int CF(t)\, dt = CF \cdot m$. By construction, the Co-Variation coefficient is non-negative and would be zero only in the extreme case where the facility generates electricity at times when prices are zero. Assuming net metering, that is $p(t) = p^o(t)$ for all t, the solar facility can be shown to be cost competitive whenever:

[21] At the end of this subsection, we consider alternative specifications, in particular the possibility that the OT remains time invariant.

$$\Gamma \cdot p \geq LCOE. \tag{18}$$

Intuitively, the economics of solar power improves if the solar energy source generates most of its output during peak price periods. To illustrate, we re-write the Co-Variation coefficient as:

$$\Gamma = 1 + \text{cov}(\epsilon(\cdot), \mu(\cdot)). \tag{19}$$

Thus, the solar power source exhibits *value synergies* with the ToU price distribution, and $\Gamma > 1$, if and only if there is a positive covariance between $\epsilon(\cdot)$ and $\mu(\cdot)$.[22] Earlier work has shown that in California there is indeed a positive covariance between ToU prices for commercial users and the solar PV generation pattern; see, for instance, Borenstein (2008) and Reichelstein and Sahoo (2015). Their estimates point to a Co-Variation coefficient close to $\Gamma = 1.1$.

To incorporate ToU pricing into our characterization of cost competitiveness with net metering restrictions, we redefine:

$$\hat{z}(k|\bar{k}) \equiv \frac{1}{m \cdot CF \cdot k} \cdot \left[\int_0^m z(t|k, \bar{k}) \cdot \mu(t)\ dt \right]. \tag{20}$$

As argued in the previous subsection, the function $z(k|\bar{k})$ is equal to one for small values of k, because $z(t|k, \bar{k}) = k \cdot CF(t)$ for small systems, provided the household consumes a minimal amount of electricity at all times. For the same reason, $\hat{z}(k|\bar{k}) = \Gamma$ for sufficiently small values of k. With ToU pricing, we redefine the Hourly Contribution Margin as:

$$HCM(k|\bar{k}, p(\cdot), p^o(\cdot)) \equiv \hat{z}(k|\bar{k}) \cdot p + [\Gamma - \hat{z}(k|\bar{k})]p^o - LCOE. \tag{21}$$

For small solar systems, the effect of time of use pricing on the hourly contribution margin therefore is to simply scale up this margin by the Co-Variation coefficient. For systems of generic size k, we obtain the following analogue of Proposition 1 above:

[22] Formally the covariance between $\epsilon(\cdot)$ and $\mu(\cdot)$ can be defined as:

$$\text{cov}(\epsilon(\cdot), \mu(\cdot)) \equiv \frac{1}{m} \int_0^m (\epsilon(t) - 1) \cdot (\mu(t) - 1) \cdot dt.$$

Proposition 1′ *Given load profile, $L(\cdot)$, ToU price schedule, $p(\cdot)$, and OT schedule, $p^o(\cdot)$, a solar installation of k kW of peak capacity below the threshhold size, $\hat{k}(\bar{k})$, is cost competitive if and only if:*

$$HCM(k|\bar{k}, p(\cdot), p^o(\cdot)) \geq 0. \tag{22}$$

With time of use pricing we also obtain the following analogue of Proposition 2, showing that with net metering the optimal size for a solar rooftop system is equal to the threshold value $\hat{k}(\bar{k})$.[23]

Proposition 2′ *With ToU pricing, suppose that $LCOE > p^-$ and net metering applies in the sense that $p(t) = p^o(t)$ for all t. The optimal size of the solar PV system is then equal to the threshold size, $\hat{k}(\bar{k})$, provided $p < \frac{LCOE - p^-}{\Gamma - 1}$.*

The last inequality in Proposition 2′ will be met in our applications below because in all three locations $1 < \Gamma < 1.1$ and $p < 10 \cdot (LCOE - p^-)$. We finally obtain the following analogue of Proposition 3 in Section 2.1. To that end, we define $\hat{z}^-(k|\bar{k}) \equiv \hat{z}(k|\bar{k}) + \hat{z}'(k|\bar{k}) \cdot k$.

Proposition 3′ *Suppose that $\hat{z}^-(k|\bar{k}) > 0$ for all $k < \hat{k}(\bar{k})$ and $\hat{z}^-(k|\bar{k}) < \frac{LCOE - p^- + (\Gamma - 1)p^o}{p - p^o}$ for all $k > \hat{k}(\bar{k})$. The optimal size of the solar PV system is then equal to the threshold size, $\hat{k}(\bar{k})$, provided $\Gamma \geq 1$ and $p \geq p^o \geq LCOE$.*

Taken together, our findings for both the time-invariant and time of use pricing regime indicate that the optimal residential PV system is "sticky" in response to net metering restrictions, provided the overage tariff is, on average, at least equal to the LCOE. Since our main interest is to understand the impact of net metering restrictions on solar PV investments, we seek to characterize numerically the changes in the optimal system size that emerge in case the average overage tariff is set below the LCOE. With ToU pricing, an interior optimum k^* must now satisfy the first-order condition:

$$\hat{z}^-(k^*|\bar{k}) = \frac{LCOE - \Gamma \cdot p^o}{p - p^o}. \tag{23}$$

As noted in Section 2.1 above, the impact of net metering restriction can therefore be captured by the function $\hat{z}^-(k^*)$.

[23]We omit the proofs of Propositions 2′ and 3′ since the corresponding steps mirror those in the proofs of Propositions 2 and 3.

To conclude this subsection, we observe that if there is ToU pricing but the OT were to remain time-invariant, the resulting expression for the hourly contribution margin can be expressed as a combination of the results in Propositions 1 and 1′ above. Specifically, in that case:

$$HCM(k|\bar{k}, p(\cdot), p^o) \equiv p^o \cdot (1 - z(k|\bar{k})) + p \cdot \hat{z}(k|\bar{k}) - LCOE. \tag{24}$$

We finally recall that our model has made the simplifying assumption that there is no solar system degradation, that is, the energy produced remains constant across the years. For high-end solar modules, the degradation factor is usually quoted around 0.997. If this factor is recognized explicitly, there will be annual threshold levels which increase geometrically over time. It may then become advantageous to oversize the solar installation initially so that the aggregate surplus constraint is violated in the early years in order to get higher cash flows out of the system in later years. We note, however, that the range of possible thresholds levels is quite small for a degradation factor equal to .997. To illustrate, the threshold size for year 10, for instance, would be 3% larger than that for year 1 since $\frac{1}{.997^{10}} \approx 1.03$.

3 Projected Impact of Net Metering Restrictions

We apply the preceding model framework to specific locations within three U.S. states which have recently issued rulings regarding net metering rates. Our calculations apply to Los Angeles (California), Las Vegas (Nevada), and Honolulu (Hawaii). The public utilities commission in California has largely kept net metering intact, while Nevada intends to reduce the OT gradually to wholesale rates, and Hawaii chose an OT that falls between these two extremes.[24] We employ the preceding model framework to predict the impact that changes in the applicable OT will have on the optimal solar installation size k^*, for both time-invariant retail rates and time-of-use pricing.

Key Model Variables

The five central variables in our model are: the LCOE, the load profile of the household modeled as a function of the size of the house ($\bar{k}$), the threshold solar installation capacity, $\hat{k}(\bar{k})$, the generation profile of the solar facility, and the prevailing residential retail rates (both time- invariant and ToU rates).[25] In calculating the LCOE for these three locations, we employ the "bottom-up" cost approach in Comello and Reichelstein (2016). This approach aggregates all cost components of the LCOE, while also accounting for differences in materials, labor and taxes (SEIA, 2016; NREL, 2015b; RSMeans, 2015; Barbose et al., 2015; Chung et al., 2015; GTM Research, 2016) across different geographies. This LCOE calculation incorporates the current 30% ITC, the 50% bonus depreciation and the accelerated depreciation schedule currently available to solar assets. Table A.1 in the Appendix provides a comprehensive list of the input variables underlying the LCOE.

Residential demand profiles are based on the consumption pattern exhibited by NREL's Building America B10 Benchmark small, medium and large-sized references (single-unit detached house) in a typical meteorological year (TMY3) applied to the climate regions relevant

[24]The utility serving the vast majority of Los Angeles is LADWP. As a municipally owned utility it is not under the jurisdiction of the California Public Utility Commission (CPUC). However, the net-metering rules adopted by LADWP closely mirror those of the CPUC (LADWP, 2016).

[25]*Residential Net-Metering Cost Analysis* within the *Supplementary Information* and the Appendix detail all input variables and calculations.

to Los Angeles, Las Vegas and Honolulu.[26,27] This raw input is averaged across the daily hours to form two "representative" daily demand profiles for each of the house sizes in a given location: a representative summer - and a representative winter day. These daily demand curves are weighted by the length of the summer and winter seasons to yield an annualized daily demand profile. The definition of seasons follows that of the utility service providers in the respective locations.[28] We develop nine annualized daily demand profiles: small, mid-size and large for each location. Appendix C provides details on the annual and seasonal demand profiles for representative households (small, mid-size and large) for each location.

The maximum capacity, $\bar{k}$, of a rooftop solar facility is determined as a function of house size. It is assumed that a house roof is flat (i.e., has zero pitch), and the surface area of the roof is equal to the house floor area. The maximum area available for a solar installation is taken as 26% of the roof, based on estimates from Gagnon et al. (2016). From this area and given an assumed solar efficiency of 20% or $200W/m^2$, we calculate the maximum capacity, $\bar{k}$. Appendix F reports the $\bar{k}$ values for each house size in each geographic location.

The threshold capacity, $\hat{k}(\bar{k})$, is determined by matching the annualized daily demand (kWh) to annualized daily generation (kWh) produced by a corresponding roof-top installation in a specific location. Demand as a function of maximum solar installation capacity is determined by relating $\hat{k}(\bar{k})$ to annual average daily load, and normalizing the result by the mid-size house in each location. Thus $\beta(\bar{k}) = 1$ for the mid-size house in each geographic location. The function $\beta(\cdot)$ is taken to be a quadratic function for modeling purposes (Appendix F).

Residential solar generation profiles are provided by the output of the NREL PVWatts simulation tool using each geographic location under TMY3 conditions (NREL, 2015a). As with demand profiles, representative summer and winter supply days are generated from the

[26]The B10 small, medium and large reference cases (floor areas of approximately 1,000, 2,000 and 3,000 sq ft respectively) represent houses built to the 2009 International Energy Conservation Code, as well as the federal appliance standards in effect as of January 1, 2010, and lighting characteristics and miscellaneous electric loads most common in 2010 (Hendron and Engebrecht, 2010; NREL, 2010; Baechler et al., 2015). The resulting demand profiles may underestimate the total annual consumption for each reference, as previous housing vintages would be less energy efficient.

[27]The TMY3s are data sets of hourly values of solar radiation and meteorological elements for a 1-year period, derived from a period of 1976–2005. Their intended use is for computer simulations of solar energy conversion systems (NREL, 2016a). TMY3 simulation data provides hourly demand across a year (8,760 data points).

[28]See, Los Angeles Department of Water and Power (LADWP, 2016) for Los Angeles, NV Energy (NV Energy, 2016b,c) for Las Vegas and Hawaiian Electric Company (HECO, 2016a,b) for Honolulu.

raw hourly simulation data, and the duration of the seasons is taken from the corresponding utility. The reader is referred to Appendix D for annual and seasonal generation profiles representing a typical day.

The current residential retail rates used in our calculations are those that the local utilities charge their residential customers. For time-invariant rates, we calculate an effective rate which includes items such as non-fuel charges, base-fuel charges and any additional volumetric charges. We do not include any customer charges, as presumably this charge would be equally applicable with and without solar installations. In the case of a tariff block structure (e.g., Los Angeles), the retail rate is calculated from the average monthly demand and the individual block rates to arrive at an average retail rate across all hours of the year.[29] For ToU prices, we determine each hourly charge by season (summer or winter) as an hour-based weighted average of the charge in that hour given that *base*, *low-peak* or *high-peak* rates may apply. For example, LADWP charges a high-peak rate during the hours of 1:00pm – 5:00pm Monday through Friday, and a base rate for the same hours on the weekend. A weighted average is required to compute a representative hourly charge across the days of the year. Appendix E provides the requisite details.

3.1 Findings for Los Angeles

Simulation results for Los Angeles show a relatively flat load profile during the hours of solar generation, with a late evening peak demand of approximately 1.5 kW. This demand profile does not exhibit much variation across seasons, with summer defined as June to September, and winter as October to May. Solar generation has a stronger seasonal component, with capacity factors of 22% and 17% for summer and winter respectively. The weighted average time-invariant retail price is \$0.159 per kWh, while ToU pricing ranges between \$0.133 and \$0.149 per kWh on an annualized basis. Importantly, we calculate the LCOE as \$0.118 per kWh. Representative plots of demand, output generation (based on a 4.85 kW peak capacity system for a mid-size house) and retail rates are shown in Figures 3 and 4.

With ToU pricing, the spread between baseline and peak rates is fairly muted (\$0.131

[29]This weighted average approach introduces an inaccuracy, as it undervalues smaller solar installations and overvalues larger installations. However, it can be verified numerically that the practical effect of this averaging technique is minor in terms of our conclusions. The reason is that in the case of Los Angeles the two block rates are only approximately 3 cents apart and thus rather similar results are obtained for any rate in between those two tariffs.

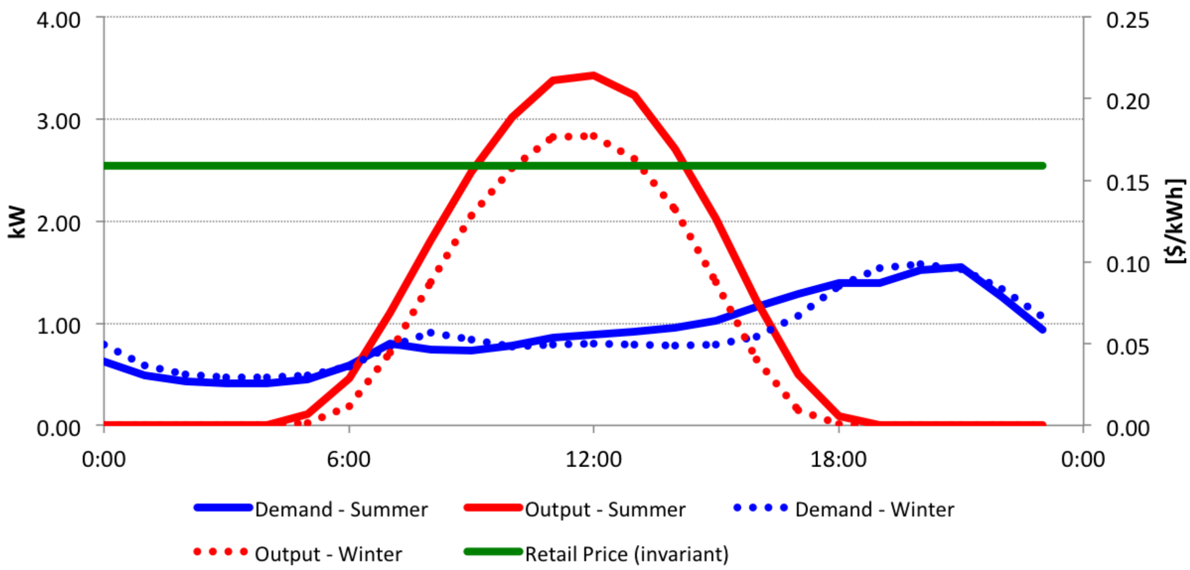

Figure 3: Los Angeles, CA demand, generation and time-invariant pricing.

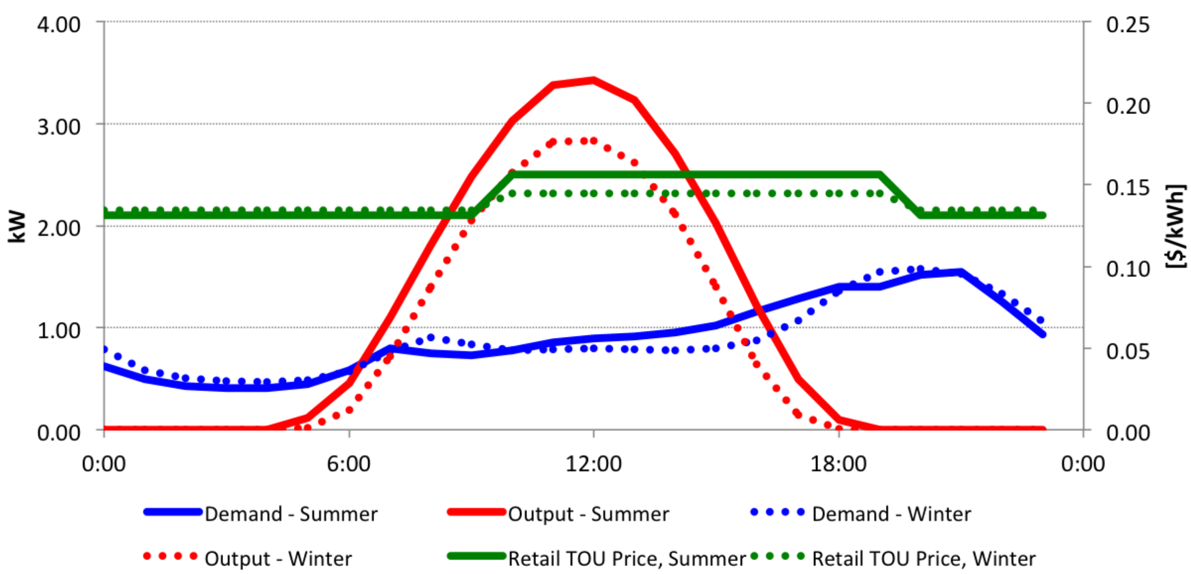

Figure 4: Los Angeles, CA demand, generation and time-of-use pricing.

and \$0.156 per kWh, and \$0.134 and \$0.145 per kWh for summer and winter respectively). While peak-pricing is in effect for the majority of hours of solar generation, the Co-Variation coefficient between price and generation is 1.038, a value that is somewhat lower than that observed for the other locations in our study.

For a mid-size house in Los Angeles, our calculations lead to values of $\bar{k} = 9.9$ and $\hat{k}(\bar{k}) = 4.85$. Figure 5 shows the effect of overage tariffs that are set at, or below, the

LCOE on the optimal k^* for the mid-size house case (for small and large-size houses, refer to Appendix G). We note that for Los Angeles, the function $z^-(\cdot)$, introduced in Section 2, is positive on the relevant range of a capacity installation up to 10 kW of peak power. For a deviation of less than 2.5% from the LCOE, the optimal system size remains $k^* = \hat{k}(\bar{k}) = 4.85$ kW, as predicted in Section 2. For overage tariff deviations beyond that, however, k^* drops abruptly, settling under 2 kW once the deviation for LCOE exceeds 12.5%.

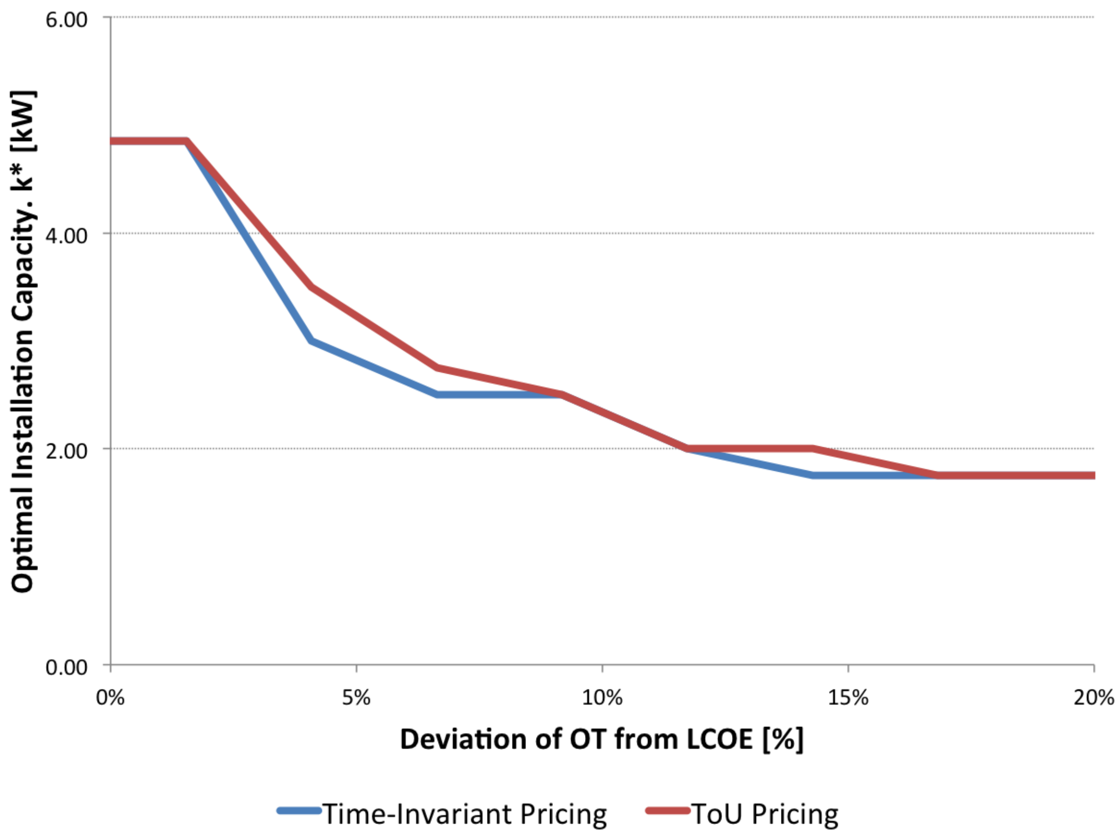

Figure 5: Optimal size of the residential solar system for a mid-size house in Los Angeles, CA, as a function of percentage difference from LCOE.

3.2 Findings for Las Vegas

Simulation results for Las Vegas show load profiles that are quite distinct for the summer and winter seasons. During the summer months (June through September), typical residential consumption rises coincidentally during the hours of solar system generation, with an evening peak demand of approximately 3.0 kW. In contrast, during the winter months (remainder of the year), demand is relatively flat, with a 2-hour later evening peak of approximately 1.8 kW (40% less than summer). Solar generation too has a distinct seasonal component, with capacity factors of 24% and 19% for summer and winter, respectively. The average time-invariant retail rate is \$0.113 per kWh, while ToU prices range between \$0.049 and \$0.151 per kWh. The calculated LCOE at \$0.104 per kWh is distinctly lower than in California, owing to differences in labor costs and higher insolation. Representative plots of demand, generation (based on a 5.59 kW peak capacity system for a mid-size house) and retail rates are shown in Figures 6 and 7.

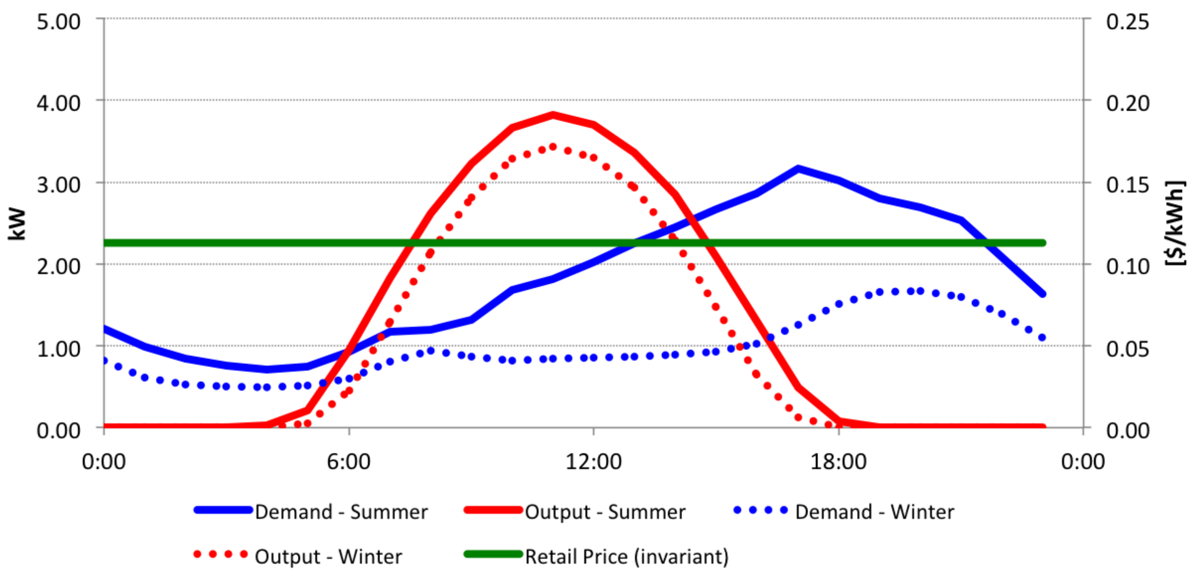

Figure 6: Las Vegas, NV demand, generation and time-invariant pricing.

While the summer ToU prices are reflective of the summer demand profile, peak pricing is not coincident with peak solar power generation. The Co-Variation coefficient relating price and generation across time is 1.052. Moreover, the difference between weighted summer baseline and peak rates is large: \$0.059 per kWh baseline compared to \$0.364 per kWh during peak times. Finally, the winter ToU rate – which includes 9 months of the year – does not have any differentiation across hours of the day, with a constant low rate of \$0.045

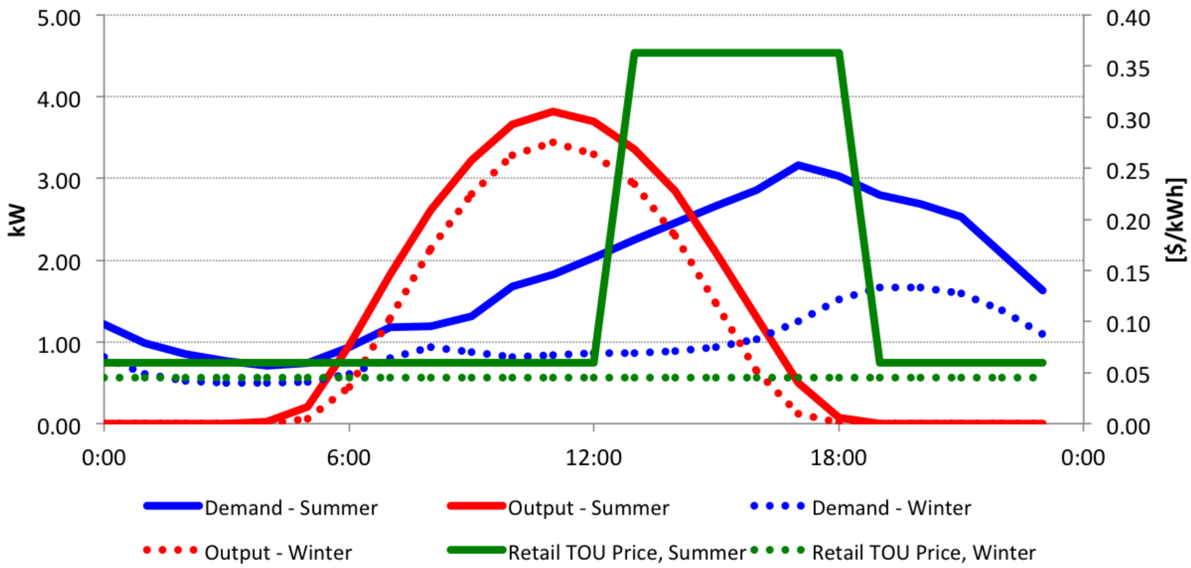

Figure 7: Las Vegas, NV demand, generation and time-of-use pricing.

per kWh. These data points provide intuition for why solar would not be competitive in Nevada, even with full net metering, if the current optional ToU pricing regime became mandatory.

For a mid-size house in Las Vegas, we find values of $\bar{k} = 8.83$ and $\hat{k}(\bar{k}) = 5.59$. Figure 8 graphs the size of the optimal mid-size residential solar installation as a function of a changing OT, starting at $p^o = LCOE$ (for small and large-size houses, refer to Appendix G). Like in the case for Los Angeles, we find that an OT equal to the LCOE would have no impact on the resulting capacity, that is, $k^* = \hat{k}(\bar{k}) = 5.59$ kW. However, further reductions in the overage tariff would have immediate consequences: for an OT that is set 10% or more below the LCOE, the resulting optimal installations would drop to 2 kW or even smaller sizes.

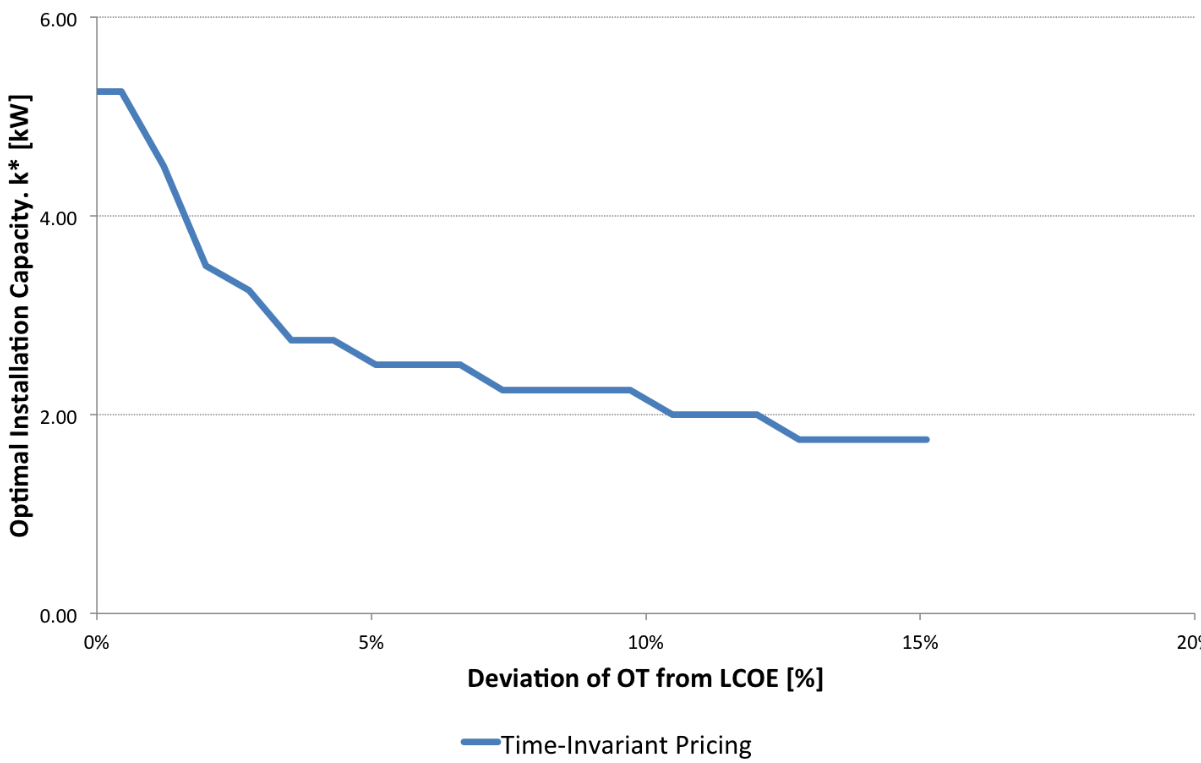

Figure 8: Optimal size of the residential solar system for a mid-size house in Las Vegas, NV, as a function of the percentage difference from LCOE.

3.3 Findings for Honolulu

Similar to Los Angeles, Honolulu consumption patterns show a relatively flat load profile during the hours of generation, with a late evening peak demand of approximately 2.5 kW. The demand profile shows relatively little variation across seasons, with summer defined as April to October, and winter as November to March. The pattern of solar generation has a relatively small seasonal component compared to the other two locations, with capacity factors of 19% and 17% for summer and winter respectively. Average time-invariant retail prices are at $0.28 per kWh, while ToU pricing ranges between $0.249 and $0.325 per kWh on an annualized basis. For Honolulu, the LCOE is $0.135 per kWh. Representative plots for demand, generation (based on a 8.69 kW peak capacity system for mid-size homes) and retail rates are shown in Figures 9 and 10.

Unlike LADWP (Los Angeles service utility) and NV Energy (Las Vegas service utility), the Hawaiian Electricity Company (HECO) does not offer a ToU pricing structure that varies by season. Nevertheless the ToU prices are reflective of peak demand for both summer and

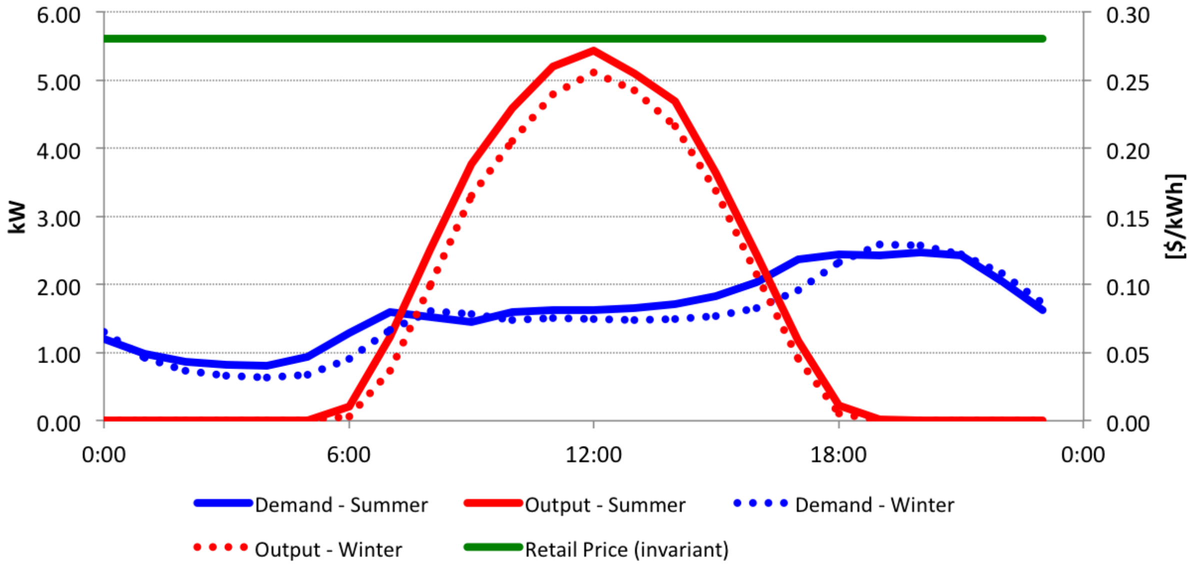

Figure 9: Honolulu, HI demand, generation and time-invariant pricing.

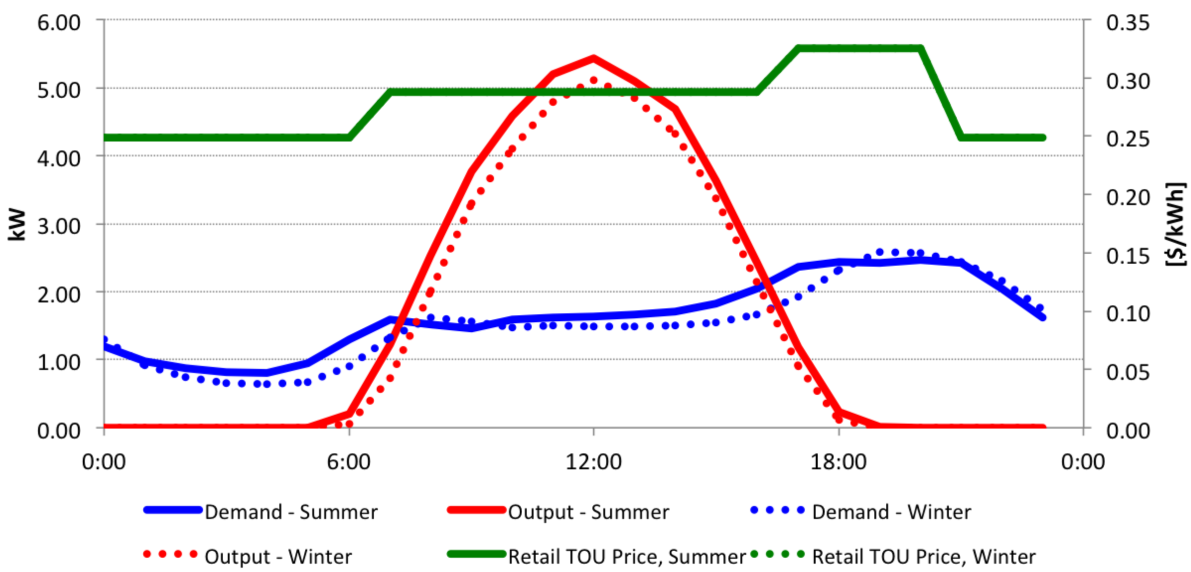

Figure 10: Honolulu, HI demand, generation and time-of-use pricing.

winter. We note that peak-prices are again not coincident with the hours of the day during which solar power generation is at its maximum. Peak-pricing occurs during the hours of waning solar generation, and mid-peak pricing is in effect during all hours of solar generation. Given these real-time effects, and the relatively small change between the two price levels ($0.325 per kWh and $0.288 per kWh respectively), the Co-Variation coefficient is 1.043.

For a mid-size house in Honolulu, our calculations lead to values of $\bar{k} = 10.18$ and

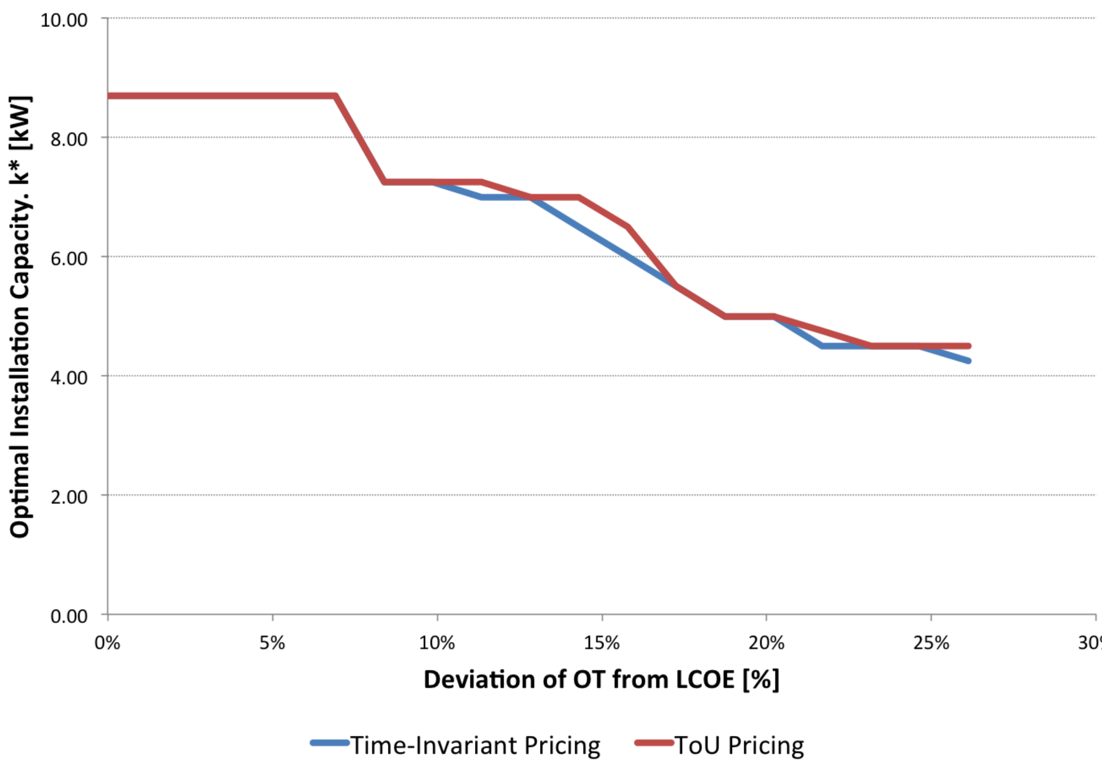

Figure 11: Optimal size of the residential solar system for a mid-size house in Honolulu, HI, as a function of the percentage difference from LCOE.

$\hat{k}(\bar{k}) = 8.69$. Figure 11 shows the sensitivity of a solar investment for a mid-sized house to an OT below the LCOE for the both the time-invariant and ToU scenarios. For an OT set at least 15% below LCOE, the optimal installation size will drop sharply from $k^* = \hat{k}(\bar{k}) = 8.69$ kW, to levels to around 5 kW. In contrast to the previous two scenarios, though, the optimal system size then stabilizes at a relatively robust around 4 kW, even for significant deviations from the LCOE. We attribute this finding to the fact that in Hawaii, the retail rate is exceptionally high and therefore the avoided cost of purchases from the grid provides sufficiently strong investment incentives even if the OT falls substantially below the LCOE.

4 Discussion

Our analysis has focused on California, Nevada and Hawaii, as these states have recently adopted new policies on net metering. The actions taken in these states are likely to set precedents for the other 38 states (plus the District of Columbia) that currently have net metering provisions in place. In particular, among all the states with net metering policies, a significant 24 have indicated that they either are in the process of evaluating the treatment of distributed generation or that they intend to do so in the near future (NC CETC and Meister Consultants Group, 2016).

One common prediction emerging from the three sample settings in our numerical analysis is that the optimal (NPV maximizing) size of residential solar systems will be "sticky" provided overage tariffs are set somewhere in between the LCOE and the retail rate p. Thus, regulators have considerable leeway in imposing restrictions on current net metering rules without disabling the incentives for investors to continue to install residential solar PV systems that are effectively chosen in size so as not to violate the aggregate surplus constraint already in use.

At the same time, Figures 5, 8 and 11 reveal that an OT equal to the LCOE is an effective tipping point in terms of the requisite incentive to invest. The shape of the optimal installation size, k^*, in all three locations shows that the NPV maximizing size of an average residential system is rather sensitive to overage tariffs set below the LCOE. In the case of Hawaii, this effect will be relatively muted owing to the fact that the retail rate is far above the LCOE, that is, \$0.28 per kWh compared to \$0.135 per kWh.

Our modeling analysis in Section 2 is predicated on the notion that investors seek to maximize the available NPV and that, provided the cost of capital is specified appropriately, any project with a maximized NPV value greater than zero will be accepted. An NPV of zero would lead to a "knife-edge" situation leaving the investor just indifferent. To examine the economic rents corresponding to different OT values, we consider the *Economic Profit Margin*, EPM, given by the ratio of the project's NPV to the initial capital expenditure.[30] In our notation, this margin is given by:

[30] This ratio can be interpreted as an economic rate of return, because it is calculated as the difference between the present value of future operating cash flows and the initial investment, calibrated by the initial investment.

$$EPM(k) \equiv \frac{NPV(k|p(\cdot), p^o(\cdot))}{SP \cdot k}. \tag{25}$$

The following Tables 1, 2 and 3 show the NPV and the resulting economic profit margins for mid-size, small and large houses, each evaluated at the constrained optimum for three alternative OT's: retail rate, LCOE and 85% of the LCOE.

Table 1: *Mid-size house: NPV and EPM at the optimal k^* for alternative OTs.*

	Los Angeles, CA			Honolulu, HI			Las Vegas, NV		
Overage Tariff	**p**	**LCOE**	**85% LCOE**	**p**	**LCOE**	**85% LCOE**	**p**	**LCOE**	**85% LCOE**
k^*	4.85 kW	4.85 kW	2.00 kW	8.69 kW	8.69 kW	6.75 kW	5.59 kW	5.59 kW	1.75 kW
$NPV(k^*)$	\$2,142	\$892	\$637	\$13,715	\$6,128	\$5,198	\$743	\$329	\$179
$EPM(k^*)$	13%	6%	9%	47%	21%	23%	4%	2%	3%

Table 2: *Small house: NPV and EPM at the optimal k^* for alternative OTs.*

	Los Angeles, CA			Honolulu, HI			Las Vegas, NV		
Overage Tariff	**p**	**LCOE**	**85% LCOE**	**p**	**LCOE**	**85% LCOE**	**p**	**LCOE**	**85% LCOE**
k^*	2.51 kW	2.51 kW	1.00 kW	4.70 kW	4.70 kW	3.75 kW	2.91 kW	2.91 kW	1.00 kW
$NPV(k^*)$	\$730	\$301	\$207	\$7,346	\$3,207	\$2,731	\$374	\$156	\$86
$EPM(k^*)$	9%	4%	6%	47%	20%	21%	4%	2%	3%

Table 3: *Large House: NPV and EPM at the optimal k^* for alternative OTs.*

	Los Angeles, CA			Honolulu, HI			Las Vegas, NV		
Overage Tariff	**p**	**LCOE**	**85% LCOE**	**p**	**LCOE**	**85% LCOE**	**p**	**LCOE**	**85% LCOE**
k^*	7.25 kW	7.25 kW	3.00 kW	15.27 kW	15.27 kW	12.00 kW	10.02 kW	10.02 kW	2.75 kW
$NPV(k^*)$	\$3,515	\$1,461	\$1,079	\$24,730	\$10,992	\$9,320	\$1,292	\$552	\$303
$EPM(k^*)$	15%	6%	12%	48%	21%	23%	4%	2%	4%

Reducing the OT to 85% of LCOE has a sharp effect in Los Angeles and Las Vegas across the house sizes examined. This finding reflects the relatively small difference between retail rates and LCOE in these jurisdictions. Notably for the small and mid-size house settings, significant reductions in the OT below the LCOE renders optimal installation capacities to between 1 kW to 2 kW. It is plausible that such system sizes are so small that developers will exit these segments entirely.[31]

[31] The NPV attained by small solar system sizes may, in fact, be even be smaller than indicated here if the system price associated with small systems suffers some "diseconomies of scale" relative the system prices we calibrated for mid-size or larger houses. GTM Research (2016) reports some evidence in this regard.

We recall from the modeling part in Section 2 that for any given overage tariff the incentive to invest in rooftop solar has two distinct sources: i) the avoided cost of electricity purchases at the retail rate; and, ii) the revenue obtained from surplus electricity which is proportional to the OT. The second source of investment incentive is effectively eliminated if the OT is equal to the LCOE. The figures in Tables 1, 2 and 3 show that while the first source is by itself strong enough to sustain an investment incentive for system sizes equal to those that would emerge under full net metering, setting $OT = LCOE$ would also lead to a situation in which the investor loses most economic rents in comparison to a scenario of full net metering.[32] To reinforce this point, it will be useful to compute the *internal rate of return* (IRR) corresponding to the optimal k^* for a mid-size house, assuming that the overage tariff is set equal to the LCOE in the respective location. Benchmarking against the assumed cost of capital at 7.5%, we then obtain an IRR of a mere 8.4% for California, 10.8% for Honolulu, and 7.7% for Las Vegas.

From the perspective of a regulator that seeks to impose an OT sufficient to motivate sustained investment in residential solar systems, but do so in a manner that minimizes the implicit subsidy granted to investors, the LCOE provides an obvious benchmark. Our finding that even small errors in the identification of the LCOE could entail a sharp drop-off in investment activity suggests that it might be prudent to add a safety margin.[33] To illustrate, if the overage tariff for Los Angeles were set 10% above the LCOE, the economic profit margin corresponding to an optimal 4.85 kW facility would increase to 8% and the corresponding IRR to 9%.

The levelized cost of solar power has been declining sharply and consistently across the different segments of the industry over the past decade. To the extent that a regulator seeks to tie the overage tariff to the underlying LCOE, possibly marked-up by a suitable safety margin, overage tariffs could be reduced on a periodic basis, e.g., a two year cycle, to reflect future reductions in the levelized cost. To ensure proper investment incentives, incumbent solar installations would, of course, have to anticipate that the OT applicable to them would remain at the original level that applied at the time the system went into operation.

[32]The values in Tables 1 – 3 illustrate the well known point that maximizing the NPV can result in a different level of investment than that which maximizes the EPM, because the latter is a ratio.

[33]Adding a safety margin to the LCOE for the purposes of setting the OT could also be important if some of the costs associated with a new solar installation do not (as we have assumed) scale proportionally with the size of the installation. For instance, customer acquisition costs or the rooftop lending fee that the investor effectively pays to the homeowner may have a significant fixed cost component, in which case a lower OT would not only result is a smaller sized system but in fact render such systems altogether unprofitable.

Our calculations for the three locations in California, Hawaii and Nevada, respectively, enable us to assess the likely impact of the recent net metering actions in those states on future deployments. California has opted to keep net metering intact, subject to an additional volumetric "non-bypassable" charge for solar PV homes. This charge increases the cost of grid purchases by \$0.02 to \$0.03 per kWh (CPUC, 2016) for households that connect their solar PV systems to the grid. Thus electricity exports from rooftop solar installations will be credited at the full retail rate, however electricity purchases from the grid by the household will be billed at the retail rate plus a non-bypassable charge. This "NEM 2.0" policy will have the effect of reducing the NPV in proportion to the number of kWh purchased from the grid. In our model framework, we view this surcharge as additional compensation the investor/developer must provide to the homeowner. To reflect these additional charges, equation (13) is modified to:

$$NPV(k) = (1 - \alpha) \cdot A \cdot m \cdot CF \cdot \big[HCM(k|p, p^o) \cdot k - NBC \cdot AHD\big]. \tag{26}$$

Here NBC denotes the non-bypassable charge and AHD is the average hourly residential electricity demand.[34] Using Los Angeles as a case in point, for $NBC = \$0.025/kWh$, the NPV for an installation of any size decreases by \$241. As a consequence, the economic profit margin decreases from 13.6% to 12.1% for a 4.85 kW system and from 15.0% to 14.4% for a large-size house, where $k^* = 7.25$. Despite the imposition of the non-bypassable charge, an investor/developer would still earn a significant economic profit margin for normal sized solar installations in California. These findings are robust for the state as a whole, since the average state retail rates are slightly higher than the ones for the specific Los Angeles example (EIA, 2016).

Nevada has opted to reduce net metering from retail rates to wholesale rates over a 12 year time frame, and to concurrently increase fixed charges on customers with solar installations (PUCN, 2016). The overage tariff rates will decrease once every three years, beginning in 2016 with an "excess energy credit" of \$0.09199 per kWh (NV Energy, 2016a). For Las Vegas, this implies that in 2016 the OT is 11% below the LCOE. Our model then predicts an optimal solar installation of approximately 2 kW for a mid-size house. With further declines in the OT in subsequent years, an investor/developer would find it challenging to continue operations, especially if there are ample opportunities to develop in other states with

[34] Referring to Figure 3, the AHD is obtained by dividing the area under the blue demand curve by 24.

more favorable net-metering policies. Indeed, the recent actions taken by solar developers in Nevada suggest that this net-metering ruling will put new residential solar developments on hold (NY Times, 2016).

Hawaii has decided to discontinue full net metering and instead apply an OT somewhere between \$0.18 to \$0.298 per kWh, depending on the specific Hawaiian island on which the system is deployed (HPUC, 2015). Under this "grid supply tariff", a residential household on the main island would face an \$0.18 per kWh feed-in-tariff, compared to the average invariant retail price of \$0.28 per kWh. Since both p and p^o substantially exceed the LCOE, there is effectively no economic bound on the optimal size of a residential solar installation. These net-metering provisions are to be in place until 2018, at which time the policy will be reviewed. As costs decline in the intervening years, the net-metering incentive could be reduced further without adversely effecting the pace of new residential PV deployments.

5 Conclusion

With the rapid growth of residential solar installations, utilities and other stakeholders have voiced concern that the policy of net-metering provides a cross-subsidy to distributed solar generation which is paid for by all ratepayers. In response, public utility commissions have begun to take up this regulatory issue. This paper develops a framework and methodology for predicting the impact of net metering restrictions on the deployment of residential solar. Specifically, we examine the sensitivity of investments in rooftop solar in response to overage tariffs that credit overage energy at a rate below the going retail electricity rate. We apply our model framework to locations within three states: Los Angeles (California), Las Vegas (Nevada) and Honolulu (Hawaii). Our analysis considers both time-invariant and time-of-use pricing schedules currently being offered or to be adopted in the near future.

Our findings indicate that if net metering were restricted such that the overage tariff were to be set at or above the LCOE (and below the retail rate), there would not be a material impact on the volume of new residential solar installations in the three locations considered. Investors would receive a substantially lower return than under a policy of net metering, yet the optimal (i.e., NPV maximizing) solar capacity would still be the threshold level that emerges from the aggregate surplus constraint already in place under the current net metering rules. Further, we find that the size of optimal solar PV system drops off sharply for an OT set below the LCOE. In particular, for small houses we predict that new residential PV installations would effectively come to a stand-still if the OT were set even 15% below the LCOE.

There are several promising avenues for extending the analysis in this paper. In particular, it would be desirable to adapt our analysis to net-metering (or other forms of compensation) for the commercial and industrial (C&I) solar installations. There are three key differences between residential and C&I segments. First, both the LCOE of solar facilities and the prevailing electricity rates are lower for C&I, though not necessarily proportionally so. Second, the demand profile of C&I deviates significantly from that of residential users, and is distinct across different kinds of businesses. Finally, and most importantly, C&I rate structures include demand charges, which have a significant effect on the total electricity bill of a typical customer. This latter feature will shape the economics of local power generation, and the value of storage, as the business is credited for electricity exports at a particular rate.

A Appendix

A.1 Model Input Variables

Table A.1: Comprehensive list of input parameters to the LCOE calculation model

Variable	Description	Units
$L(t)$	Load profile; consumption in hour t	kW
$\bar{k}$	Maximum feasible solar installation peak capacity	kW
$\hat{k}(\bar{k})$	Threshold peak capacity	kW
β	Load scaling factor	#
CF	Annual average capacity factor in first year	%
T	Useful economic life	*years*
m	Hours in year	*hours*
PP	Panel price	\$/W
IP	Inverter price	\$/W
BOS	Balance of system cost	\$/W
SC	System cost	\$/W
SP	System price	\$/W
FMV	Fair market value of system	\$/W
tm	Transaction margin	%
λ	Ratio of FMV/SP; mark-up factor on system price	#
c	Unit capacity cost	\$/kWh
F	Fixed operation and maintenance cost	\$/kW-yr
es	Operations and maintenance escalator	%
f	Average fixed operations and maintenance cost	\$/kWh
w	Variable operations and maintenance cost	\$/kWh
ρ	Consumer/rooftop "rental cost"	\$/kWh
r	Cost of capital	%
γ	Discount factor	#
α	Effective corporate tax rate	%
d_i	Allowable tax depreciation charge in year i	%
δ	Capitalization discount	#
Δ	Tax factor	#
ITC	Federal investment tax credit	%
HCM	Hourly contribution margin	%
$z(k\|\bar{k})$	Percentage of all generation eligible for premium	%
μ	Intertemporal variation from average retail price	#
ϵ	Intertemporal variation from average capacity factor	#
Γ	Co-variation coefficient	#
p	Average retail price of electricity	\$/kWh
p^o	Average feed-in-tariff	\$/kWh

Table A.2: Input Variables

Variable	**Units**	**Los Angeles**	**Honolulu**	**Las Vegas**
Capacity factor, CF	%	18.49	18.24	20.83
Useful economic life, T	*years*	30	30	30
Panel price, PP	\$/W	0.65	0.65	0.65
Inverter price, IP	\$/W	0.28	0.28	0.28
Balance of system cost, BOS	\$/W	2.00	2.11	1.81
System cost, SC	\$/W	2.93	3.04	2.74
Transaction margin, tm	%	10	10	10
System price, SP	\$/W	3.23	3.35	3.01
Fair market value of system, FMV	\$/W	4.03	4.00	4.05
Ratio of FMV/SP, λ	#	1.25	1.19	1.34
Fixed O & M cost, f	\$/kW-yr	22.08	22.46	22.38
Effective corporate tax rate, α	%	43.8	41.4	35
Cost of capital, r	%	7.5	7.5	7.5
Investment Tax Credit, ITC	%	30	30	30
Average fixed O & M cost, f	\$/kWh	0.017	0.018	0.016
Consumer/rooftop "rental cost", ρ	\$/kWh	0.035	0.035	0.035
Unit capacity cost, c	\$/kWh	0.169	0.177	0.139
Tax factor, Δ	#	0.388	0.465	0.379
Levelized cost of electricity, $LCOE$	\$/kWh	0.118	0.135	0.104
Average (invariant) retail price of electricity, p	\$/kWh	0.159	0.280	0.113

B Proofs of Propositions

Proof of Proposition 1

We first show that an installation of k kW has the following net-present value:

$$NPV(k|\bar{k}) = (1-\alpha) \cdot A \cdot [m \cdot CF \cdot HCM(k|\bar{k}, p, p^o) \cdot k - D(k|\bar{k})],$$

where $HCM(k|p, p^o) \equiv z(k|\bar{k}) \cdot p + (1 - z(k|\bar{k})) \cdot p^o - LCOE$. Ignoring the aggregate surplus constraint at first, operating revenue from the system at time time t in any year i is given by:

$$Rev(t|k, \bar{k}) = p^o \cdot CF(t) \cdot k + (p - p^o) \cdot z(t|k, \bar{k}), \tag{27}$$

where $z(t|k, \bar{k}) \equiv \min\{\beta(\bar{k}) \cdot L(t), CF(t) \cdot k\}$. Variable operating costs in year i are given by w_i per kWh generated and fixed annual operating costs in year i are denoted by $f_i \cdot k$ per kW installed. The overall pre-tax cash flow in year i per kW of power installed comprises operating revenues and operating costs:

$$CFL_i^+ = \int_0^m \left[(p^o - w_i) \cdot CF(t) \cdot k + z(t|k, \bar{k})(p - p^o)\right] dt - F_i \cdot k - D(k|\bar{k}).$$

The firm's taxable income in year i is given by:

$$I_i = CFL_i^+ - \lambda \cdot SP(1 - \delta \cdot ITC) \cdot d_i,$$

reflecting that for tax purposes the book value of the installation is $\lambda \cdot SP$, yet only the amount $\lambda \cdot SP(1-\delta \cdot ITC)$ can be capitalized (and subsequently depreciated) if the investor claims the the investment tax credit. Thus the after-tax cash flow in year i is given by:

$$CFL_i = CFL_i^+ - \alpha \cdot I_i.$$

At the initial point in time, when the investment is made, the investor's after-tax cash outflow is:

$$CFL_0 = SP - ITC \cdot \lambda \cdot SP - \alpha \cdot \lambda \cdot SP(1 - \delta \cdot ITC) \cdot d_0.$$

Here, the second term represents the investment tax credit while the third term captures any bonus depreciation that the investor can claim initially. The discounted value of all cash flows (net-present value) is therefore given by:

$$NPV = (1-\alpha) \sum_{i=1}^{T} CFL_i^+ \cdot \gamma^i + \alpha \cdot \sum_{i=0}^{T} SP \cdot \lambda(1 - \delta \cdot ITC) \cdot d_i \cdot \gamma^i - SP(1 - \lambda \cdot ITC). \quad (28)$$

Recalling the definition of the tax factor:

$$\Delta = \frac{1 - \lambda \cdot ITC - \alpha \cdot \lambda(1 - \delta \cdot ITC) \cdot \sum_{i=0}^{T} d_i \cdot \gamma^i}{1 - \alpha}.$$

the equation (28) can be restated as :

$$NPV = (1-\alpha)\big[\sum_{i=1}^{T} CFL_i^+ \cdot \gamma^i - \Delta \cdot SP\big]. \quad (29)$$

Since the levelized cost is defined as $LCOE = w + f + c \cdot \Delta$, with the definitions of f, w

and c as provided in Section 2, the expression for NPV in (27) becomes:

$$NPV(k|\bar{k}) = (1-\alpha) \cdot A \cdot \left[m \cdot CF \cdot k \Big[\frac{\int_0^m Rev(t|k,\bar{k})\, dt}{m \cdot CF \cdot k} - LCOE \Big] - D(k|\bar{k}) \right]. \tag{30}$$

The final step in the proof then recalls the expression for revenue in (27) and the identity:

$$z(k|\bar{k}) \cdot m \cdot CF \cdot k \equiv \int_0^m z(t|k,\bar{k})\, dt$$

to conclude that

$$NPV(k|\bar{k}) = (1-\alpha) \cdot A \cdot \Big[m \cdot CF \cdot k \cdot [p^o + (p - p^o) \cdot z(k|\bar{k}) - LCOE] - D(k|\bar{k}) \Big]. \tag{31}$$

Since the hourly contribution margin, HCM, was defined as $p^o + (p - p^o) \cdot z(k|\bar{k}) - LCOE$, and $D(k|\bar{k}) = 0$ for $k < \hat{k}(\bar{k})$, we have established that an investment in k kW, with $k < \hat{k}(\bar{k})$ is cost competitive if and only if $HCM(k|p,p^o) \geq 0$. ■

Proof of Proposition 2 Straightforward differentiation yields:

$$NPV'(k|\bar{k}) = (1-\alpha) \cdot A \Big[m \cdot CF \cdot [HCM(k|\bar{k}) + HCM'(k|\bar{k}) \cdot k] - m \cdot CF \cdot (p^- - p^o) \cdot I_{\{k > \hat{k}(\bar{k})\}} \Big].$$

By definition of the function $z^-(k|\bar{k}) \equiv z(k|\bar{k}) + z'(k|\bar{k}) \cdot k$, we then obtain:

$$NPV'(k|\bar{k}) = \Omega \cdot [z^-(k|\bar{k}) \cdot (p - p^o) + (p - p^o) - (p^- - p^o) \cdot I_{\{k > \hat{k}(\bar{k})\}}], \tag{32}$$

where Ω is a constant and $I(\cdot)$ is the indicator function. It follows, that with net-metering ($p = p^o$), $NPV'(k|\bar{k}) > 0$ for $k \leq \hat{k}(\bar{k})$, but $NPV'(k|\bar{k}) = p^- - LCOE < 0$ for $k > \hat{k}(\bar{k})$.

■

Proof of Proposition 3 Following the same steps as in the proof of Proposition 2, we obtain:

$$NPV'(k|\bar{k}) = \Omega \cdot [z^-(k|\bar{k}) \cdot (p - p^o) + (p - p^o)] > 0, \tag{33}$$

for $k \leq \hat{k}(\bar{k})$, provided $z^-(k|\bar{k}) > 0$. For $k \leq \hat{k}(\bar{k})$:

$$NPV'(k|\bar{k}) = \Omega \cdot [z^{-}(k|\bar{k}) \cdot (p - p^o) + (p - LCOE)] < 0, \tag{34}$$

given the assumptions in the proposition. ■

Proof of Proposition 1′

The argument proceeds along the lines of Proposition 1. As argued in the text, with ToU pricing, revenues are given by:

$$Rev(t|k, \bar{k}) = p^o(t) \cdot CF(t) \cdot k + (p(t) - p^o(t)) \cdot z(t|k, \bar{k}). \tag{35}$$

Therefore, the life-cycle discounted revenue becomes:

$$A \cdot \int_0^m Rev(t|k, \bar{k})\ dt \cdot \gamma^i = CF \cdot A \cdot [\Gamma \cdot p^o + (p - p^o) \cdot \int_0^m z(t|k, \bar{k}) \cdot \mu(t)\ dt].$$

where Γ denotes the Co-Variation coefficient as defined in Equation (17). We recall the definition of $\hat{z}(\cdot)$ in Equation (20) as:

$$\hat{z}(k|\bar{k}) = \frac{\int_0^m z(t|k, \bar{k}) \cdot \mu(t)\ dt]}{m \cdot CF \cdot k}. \tag{36}$$

As in the proof of Proposition 1, the overall NPV can then be shown to be proportional to the hourly contribution margin, HCM:

$$HCM(k|\bar{k}, p(\cdot), p^o(\cdot)) \equiv \hat{z}(k|\bar{k}) \cdot p + [\Gamma - \hat{z}(k|\bar{k})]p^o - LCOE,$$

with the factor of proportionality given by $(1 - \alpha) \cdot m \cdot CF \cdot A \cdot k$. ■

The proofs of Propositions 2' and 3' follow directly those in Propositions 2 and 3 and are therefore omitted.

C Demand Profiles

Raw data for demand profiles is provided by NREL (2016b), which are simulations based on NREL (2010) for small, mid-size and large houses (as defined by floor area). Input data was converted into representative demand profiles by location, by season and by house size. Seasons are based on those described by the utility having service obligation in the geographies considered (see: LADWP (2016), NV Energy (2016a) and HECO (2016a)). Representative demand profiles for each location by season and size are calculated by taking the hour-specific average across all data provided for that hour in the data set. For example, for a given season, the representative hour 1:00 is the average of all hour 1:00 within that timeframe.

Refer to the *Residential Net-Metering Cost Analysis* within the *Supplementary Information* for further information and calculations.

Table A.3: Representative Residential Demand Profiles by House Size: Los Angeles

	Small, area = 93.7 m^2			Mid-size, area = 187.4 m^2			Large, area = 281.2 m^2		
Time	Annual	Summer (Jun-Sept)	Winter (Oct-May)	Annual	Summer (Jun-Sept)	Winter (Oct-May)	Annual	Summer (Jun-Sept)	Winter (Oct-May)
1:00	0.357	0.328	0.371	0.553	0.492	0.584	0.750	0.654	0.798
2:00	0.323	0.303	0.333	0.479	0.430	0.503	0.644	0.556	0.687
3:00	0.311	0.293	0.321	0.452	0.411	0.473	0.610	0.531	0.649
4:00	0.304	0.282	0.315	0.448	0.407	0.468	0.607	0.527	0.648
5:00	0.316	0.310	0.320	0.476	0.452	0.488	0.643	0.581	0.675
6:00	0.367	0.372	0.364	0.581	0.587	0.577	0.778	0.753	0.791
7:00	0.445	0.455	0.440	0.780	0.798	0.771	1.043	1.032	1.048
8:00	0.446	0.393	0.473	0.853	0.747	0.906	1.142	0.978	1.225
9:00	0.386	0.347	0.406	0.805	0.734	0.841	1.072	0.971	1.123
10:00	0.354	0.356	0.353	0.777	0.782	0.775	1.048	1.091	1.026
11:00	0.355	0.363	0.351	0.811	0.857	0.778	1.147	1.303	1.069
12:00	0.357	0.368	0.352	0.830	0.892	0.799	1.243	1.486	1.120
13:00	0.367	0.388	0.356	0.833	0.918	0.790	1.328	1.670	1.157
14:00	0.383	0.416	0.366	0.838	0.953	0.780	1.422	1.866	1.199
15:00	0.405	0.452	0.381	0.871	1.024	0.794	1.548	2.105	1.269
16:00	0.454	0.519	0.421	0.969	1.160	0.874	1.719	2.369	1.393
17:00	0.524	0.553	0.510	1.141	1.282	1.070	1.923	2.523	1.621
18:00	0.670	0.690	0.660	1.376	1.399	1.365	2.181	2.570	1.986
19:00	0.750	0.708	0.770	1.496	1.399	1.545	2.308	2.470	2.226
20:00	0.787	0.769	0.796	1.557	1.518	1.576	2.363	2.551	2.268
21:00	0.784	0.783	0.785	1.535	1.547	1.529	2.284	2.512	2.169
22:00	0.686	0.656	0.702	1.310	1.255	1.338	1.903	1.983	1.863
23:00	0.562	0.526	0.580	1.019	0.935	1.061	1.446	1.418	1.460
24:00	0.440	0.388	0.466	0.735	0.625	0.790	1.014	0.887	1.083

Table A.4: Representative Residential Demand Profiles by House Size: Las Vegas

	Small, area = 93.7 m^2			Mid-size, area = 187.4 m^2			Large, area = 281.2 m^2		
Time	Annual	Summer (Jun-Sept)	Winter (Oct-May)	Annual	Summer (Jun-Sept)	Winter (Oct-May)	Annual	Summer (Jun-Sept)	Winter (Oct-May)
1:00	0.428	0.525	0.379	0.736	0.989	0.609	1.195	1.738	0.922
2:00	0.384	0.472	0.340	0.634	0.847	0.527	1.017	1.462	0.793
3:00	0.365	0.440	0.327	0.587	0.764	0.498	0.929	1.297	0.744
4:00	0.351	0.410	0.321	0.566	0.709	0.494	0.880	1.165	0.737
5:00	0.361	0.429	0.327	0.591	0.744	0.514	0.889	1.143	0.762
6:00	0.418	0.510	0.371	0.715	0.934	0.605	1.065	1.425	0.884
7:00	0.507	0.620	0.450	0.930	1.176	0.806	1.434	1.979	1.161
8:00	0.532	0.625	0.485	1.023	1.193	0.937	1.665	2.279	1.356
9:00	0.491	0.632	0.421	1.022	1.317	0.873	1.719	2.585	1.285
10:00	0.475	0.684	0.370	1.106	1.680	0.817	1.864	3.119	1.234
11:00	0.497	0.748	0.371	1.166	1.821	0.837	2.044	3.496	1.314
12:00	0.527	0.823	0.378	1.248	2.026	0.858	2.258	3.936	1.415
13:00	0.563	0.910	0.389	1.331	2.250	0.869	2.444	4.305	1.510
14:00	0.609	1.009	0.409	1.410	2.453	0.886	2.635	4.672	1.613
15:00	0.657	1.103	0.434	1.512	2.670	0.930	2.827	5.005	1.733
16:00	0.716	1.189	0.479	1.642	2.863	1.029	2.997	5.239	1.871
17:00	0.868	1.418	0.592	1.892	3.167	1.251	3.238	5.452	2.126
18:00	0.937	1.364	0.723	2.021	3.024	1.518	3.345	5.172	2.428
19:00	0.961	1.251	0.816	2.044	2.800	1.664	3.313	4.751	2.590
20:00	0.959	1.216	0.831	2.010	2.694	1.667	3.228	4.527	2.575
21:00	0.927	1.158	0.812	1.911	2.533	1.599	3.039	4.246	2.433
22:00	0.807	0.979	0.721	1.619	2.080	1.388	2.572	3.535	2.089
23:00	0.665	0.804	0.595	1.277	1.634	1.097	2.040	2.819	1.649
24:00	0.526	0.625	0.477	0.950	1.210	0.819	1.533	2.130	1.233

Table A.5: Representative Residential Demand Profiles by House Size: Honolulu

	Small, area = 94.8 m^2			Mid-size, area = 189.6 m^2			Large, area = 284.3 m^2		
Time	Annual	Summer (May-Oct)	Winter (Nov-Apr)	Annual	Summer (May-Oct)	Winter (Nov-Apr)	Annual	Summer (May-Oct)	Winter (Nov-Apr)
1:00	0.543	0.546	0.539	0.951	0.982	0.920	1.733	1.858	1.607
2:00	0.477	0.504	0.451	0.806	0.870	0.742	1.475	1.641	1.308
3:00	0.452	0.485	0.418	0.739	0.819	0.658	1.330	1.517	1.141
4:00	0.447	0.483	0.410	0.721	0.806	0.635	1.255	1.446	1.063
5:00	0.517	0.592	0.441	0.809	0.942	0.676	1.331	1.579	1.081
6:00	0.713	0.816	0.609	1.098	1.292	0.904	1.687	2.026	1.345
7:00	0.918	0.954	0.882	1.461	1.592	1.329	2.214	2.494	1.932
8:00	0.950	0.891	1.010	1.570	1.524	1.617	2.534	2.636	2.431
9:00	0.895	0.852	0.939	1.508	1.453	1.564	2.641	2.783	2.498
10:00	0.849	0.856	0.843	1.539	1.598	1.480	2.776	3.090	2.461
11:00	0.830	0.850	0.809	1.561	1.618	1.505	2.893	3.193	2.591
12:00	0.812	0.843	0.780	1.563	1.631	1.494	2.991	3.317	2.663
13:00	0.808	0.852	0.764	1.571	1.657	1.485	3.097	3.433	2.758
14:00	0.823	0.877	0.768	1.606	1.715	1.496	3.212	3.577	2.846
15:00	0.858	0.930	0.787	1.684	1.823	1.543	3.367	3.774	2.957
16:00	0.931	1.032	0.830	1.848	2.038	1.658	3.570	4.020	3.118
17:00	1.077	1.205	0.948	2.142	2.362	1.922	3.876	4.342	3.408
18:00	1.205	1.268	1.141	2.384	2.443	2.324	4.090	4.292	3.887
19:00	1.279	1.242	1.315	2.507	2.430	2.585	4.195	4.182	4.209
20:00	1.286	1.251	1.321	2.520	2.472	2.569	4.216	4.235	4.197
21:00	1.242	1.215	1.269	2.433	2.427	2.439	4.067	4.159	3.974
22:00	1.088	1.035	1.142	2.106	2.047	2.165	3.543	3.559	3.528
23:00	0.892	0.847	0.938	1.680	1.627	1.734	2.885	2.903	2.868
24:00	0.691	0.644	0.737	1.250	1.195	1.306	2.215	2.221	2.209

D Generation Profiles

Raw data for insolation profiles – specifically plane of array irradiance (W/m^2) and cell temperature ($°C$) – is provided by NREL (2015a). Based on the specific threshold capacity $\hat{k}(\bar{k})$ kW for each geographic location and house size, and including system losses (86%), inverter efficiency (96%) and temperature losses (97%), the AC output in kW per each hour in a year is calculated. This input data is converted into representative generation profiles by location, by season and by size. Seasons are based on those described by the utility having service obligation in the geographies considered (see: LADWP (2016), NV Energy (2016a) and HECO (2016a)). Representative generation profiles for each location by season are calculated by taking the hour-specific average across all data provided for that hour in the data set.

For example, for a given season, the representative hour 1:00 is the average of all hour 1:00 within that timeframe. Refer to the *Residential Net-Metering Cost Analysis* within the *Supplementary Information* for further information and calculations.

Table A.6: Representative Residential Solar Installation Generation Profiles: Los Angeles

	Small, $\hat{k}(\bar{k})$=2.51 kW			Mid-size, $\hat{k}(\bar{k})$=4.85 kW			Large, $\hat{k}(\bar{k})$=7.25 kW		
Time	Annual	Summer (Jun-Sept)	Winter (Oct-May)	Annual	Summer (Jun-Sept)	Winter (Oct-May)	Annual	Summer (Jun-Sept)	Winter (Oct-May)
1:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
3:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
4:00	0.001	0.001	0.000	0.001	0.002	0.000	0.002	0.004	0.000
5:00	0.027	0.059	0.011	0.052	0.114	0.021	0.078	0.170	0.032
6:00	0.145	0.238	0.099	0.281	0.460	0.191	0.420	0.687	0.286
7:00	0.437	0.569	0.372	0.845	1.099	0.718	1.263	1.642	1.074
8:00	0.796	0.938	0.725	1.538	1.812	1.402	2.300	2.708	2.095
9:00	1.136	1.283	1.062	2.195	2.480	2.052	3.281	3.707	3.068
10:00	1.392	1.564	1.306	2.690	3.023	2.524	4.022	4.519	3.773
11:00	1.558	1.747	1.463	3.010	3.376	2.827	4.500	5.046	4.226
12:00	1.569	1.774	1.466	3.032	3.429	2.833	4.532	5.126	4.235
13:00	1.460	1.674	1.353	2.821	3.235	2.614	4.217	4.836	3.907
14:00	1.195	1.401	1.093	2.310	2.707	2.111	3.453	4.047	3.156
15:00	0.833	1.049	0.726	1.610	2.026	1.402	2.407	3.029	2.096
16:00	0.432	0.631	0.333	0.835	1.219	0.644	1.249	1.822	0.962
17:00	0.137	0.258	0.076	0.264	0.498	0.147	0.395	0.745	0.220
18:00	0.020	0.049	0.006	0.039	0.095	0.012	0.059	0.142	0.017
19:00	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.001	0.000
20:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
24:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Table A.7: Representative Residential Solar Installation Generation Profiles: Las Vegas

	Small, $\hat{k}(\bar{k})$=2.91 kW			Mid-size, $\hat{k}(\bar{k})$=5.59 kW			Large, $\hat{k}(\bar{k})$=10.03 kW		
Time	Annual	Summer (Jun-Sept)	Winter (Oct-May)	Annual	Summer (Jun-Sept)	Winter (Oct-May)	Annual	Summer (Jun-Sept)	Winter (Oct-May)
1:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
3:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
4:00	0.006	0.015	0.002	0.012	0.029	0.004	0.022	0.051	0.007
5:00	0.060	0.114	0.032	0.114	0.219	0.062	0.205	0.392	0.112
6:00	0.345	0.531	0.252	0.662	1.020	0.483	1.189	1.831	0.867
7:00	0.814	1.012	0.715	1.564	1.944	1.374	2.806	3.488	2.465
8:00	1.274	1.450	1.186	2.447	2.785	2.278	4.390	4.996	4.087
9:00	1.635	1.786	1.560	3.142	3.431	2.997	5.637	6.156	5.378
10:00	1.893	2.031	1.823	3.636	3.902	3.503	6.524	7.002	6.285
11:00	1.977	2.120	1.906	3.798	4.072	3.661	6.815	7.306	6.569
12:00	1.902	2.051	1.828	3.654	3.940	3.512	6.557	7.070	6.301
13:00	1.702	1.859	1.623	3.270	3.572	3.119	5.867	6.409	5.596
14:00	1.375	1.580	1.273	2.642	3.035	2.445	4.740	5.446	4.386
15:00	0.932	1.159	0.818	1.790	2.226	1.572	3.211	3.995	2.820
16:00	0.479	0.725	0.357	0.921	1.392	0.685	1.652	2.497	1.229
17:00	0.138	0.273	0.070	0.265	0.525	0.135	0.475	0.942	0.241
18:00	0.017	0.041	0.005	0.033	0.079	0.010	0.059	0.142	0.018
19:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
20:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
24:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Table A.8: Representative Residential Solar Installation Generation Profiles: Honolulu

	Small, $\hat{k}(\bar{k})$=4.7 kW			Mid-size, $\hat{k}(\bar{k})$=8.69 kW			Large, $\hat{k}(\bar{k})$=15.27 kW		
Time	Annual	Summer (May-Oct)	Winter (Nov-Apr)	Annual	Summer (May-Oct)	Winter (Nov-Apr)	Annual	Summer (May-Oct)	Winter (Nov-Apr)
1:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
3:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
4:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
5:00	0.001	0.002	0.000	0.002	0.005	0.000	0.004	0.008	0.000
6:00	0.073	0.114	0.031	0.134	0.211	0.058	0.236	0.370	0.000
7:00	0.530	0.663	0.397	0.980	1.225	0.735	1.721	2.152	0.102
8:00	1.228	1.370	1.086	2.271	2.534	2.009	3.990	4.451	1.290
9:00	1.912	2.041	1.783	3.536	3.774	3.297	6.211	6.630	3.529
10:00	2.352	2.483	2.221	4.349	4.591	4.107	7.640	8.065	5.793
11:00	2.699	2.811	2.588	4.991	5.197	4.784	8.768	9.130	7.215
12:00	2.852	2.937	2.766	5.272	5.431	5.114	9.262	9.541	8.405
13:00	2.692	2.759	2.624	4.977	5.102	4.851	8.743	8.963	8.984
14:00	2.438	2.537	2.339	4.508	4.690	4.325	7.919	8.239	8.523
15:00	1.896	1.966	1.826	3.505	3.634	3.376	6.158	6.384	7.598
16:00	1.242	1.321	1.164	2.297	2.442	2.152	4.035	4.290	5.931
17:00	0.564	0.638	0.490	1.043	1.179	0.906	1.832	2.072	3.781
18:00	0.092	0.123	0.061	0.170	0.227	0.112	0.298	0.399	1.592
19:00	0.004	0.008	0.000	0.007	0.014	0.000	0.012	0.025	0.197
20:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
21:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
24:00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

E Retail Price Structures

E.1 Time Invariant Retail Prices

Time invariant retail prices include items such as non-fuel charges, base-fuel charges and any additional volumetric charges.[35] In the case of a tiered rate structure (e.g. Los Angeles and Honolulu), an average price for a house of given size is determined by first calculating an average monthly demand, and then applying the given tiered rate to yield a weighted charge, applicable across all hours of the year.

As an example for Los Angeles, annual-average monthly demand is calculated as approximately 655 kWh, based on representative daily demand of 21.524 kWh for a mid-size house, provided in Table A.3. Given "Zone 1" energy-based charge tiers from LADWP (LADWP (2016)), such a monthly demand crosses Tier 1 and Tier 2. Taking the weighted average of energy charge rates across tiers, the time invariant retail price for Los Angeles is calculated.

As an example for Honolulu, annual-average monthly demand for a mid-sized house is calculated as approximately 1,157 kWh, based on representative daily demand of 38.055 kWh, provided in Table A.5. Given the non-fuel energy charge tiers from HECO ((HECO, 2016a)), such a monthly demand crosses Tiers 1 and 2. Taking the weighted average of this non-energy charge rates across tiers, and adding it to the other residential rate components (base fuel charge, the residential DSM adjustment and the renewable energy infrastructure charge), we obtain the time-invariant retail price for Honolulu. Refer to the *Residential Net-Metering Cost Analysis* within the *Supplementary Information* for further information and calculations.

[35] Customer charges are not included, as presumably this charge would be equally applicable to residential customers with and without solar installations, and thus would not affect competitive comparison.

Table A.9: Representative Time Invariant Prices for Mid-Sized Houses

Annualized [$/kWh]							
Time	Los Angeles, CA			Las Vegas, NV	Honolulu, HI		
	small	mid-size	large		small	mid-size	large
1:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
2:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
3:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
4:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
5:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
6:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
7:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
8:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
9:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
10:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
11:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
12:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
13:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
14:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
15:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
16:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
17:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
18:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
19:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
20:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
21:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
22:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
23:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282
24:00	0.145	0.159	0.164	0.113	0.277	0.280	0.282

E.2 Time of Use Retail Prices

Time of use retail prices include items such as non-fuel charges, base-fuel charges and any additional volumetric charges.[36] Seasons are based on those described by the utility having service obligation in the geographies considered (see: LADWP (2016), NV Energy (2016a) and HECO (2016a)).

Intra-day rates are calculated by taking the hour-weighted rate average across days to determine a representative rate. As an example, HECO offers Honolulu residents the TOU rate under *Schedule TOU-R - Residential Time-Of-Use Service, Sheet No. 86.* Priority-peak, mid-peak and off-peak pricing are offered by the rate schedule depending on hours of the day, and day of the week. For example, from 5pm – 9pm, Monday to Friday, priority-peak pricing applies, whereas on weekends these hours face mid-peak pricing. To determine pricing for the hours of 5pm – 9pm on a representative day, an hour-weighted rate is determine, in this case $\frac{5}{7}$ priority-peak pricing added to $\frac{2}{7}$ mid-peak pricing. Refer to the *Residential Net-Metering Cost Analysis* within the *Supplementary Information* for further information and calculations.

[36]Customer charges are not included, as presumably this charge would be equally applicable to residential customers with and without solar installations, and thus would not affect competitive comparison.

Table A.10: Representative Time-of-Use Prices

	Los Angeles, CA [$\kWh]			Las Vegas, NV [$\kWh]			Honolulu, HI [$\kWh]		
Time	Annual	Summer (Jun-Sept)	Winter (Oct-May)	Annual	Summer (Jun-Sept)	Winter (Oct-May)	Annual	Summer (May-Oct)	Winter (Nov-Apr)
1:00	0.133	0.131	0.134	0.050	0.060	0.045	0.249	0.249	0.249
2:00	0.133	0.131	0.134	0.050	0.060	0.045	0.249	0.249	0.249
3:00	0.133	0.131	0.134	0.050	0.060	0.045	0.249	0.249	0.249
4:00	0.133	0.131	0.134	0.050	0.060	0.045	0.249	0.249	0.249
5:00	0.133	0.131	0.134	0.050	0.060	0.045	0.249	0.249	0.249
6:00	0.133	0.131	0.134	0.050	0.060	0.045	0.249	0.249	0.249
7:00	0.133	0.131	0.134	0.050	0.060	0.045	0.288	0.288	0.288
8:00	0.133	0.131	0.134	0.050	0.060	0.045	0.288	0.288	0.288
9:00	0.133	0.131	0.134	0.050	0.060	0.045	0.288	0.288	0.288
10:00	0.149	0.156	0.145	0.050	0.060	0.045	0.288	0.288	0.288
11:00	0.149	0.156	0.145	0.050	0.060	0.045	0.288	0.288	0.288
12:00	0.149	0.156	0.145	0.050	0.060	0.045	0.288	0.288	0.288
13:00	0.149	0.156	0.145	0.050	0.364	0.045	0.288	0.288	0.288
14:00	0.149	0.156	0.145	0.151	0.364	0.045	0.288	0.288	0.288
15:00	0.149	0.156	0.145	0.151	0.364	0.045	0.288	0.288	0.288
16:00	0.149	0.156	0.145	0.151	0.364	0.045	0.288	0.288	0.288
17:00	0.149	0.156	0.145	0.151	0.364	0.045	0.325	0.325	0.325
18:00	0.149	0.156	0.145	0.151	0.364	0.045	0.325	0.325	0.325
19:00	0.149	0.156	0.145	0.151	0.060	0.045	0.325	0.325	0.325
20:00	0.133	0.131	0.134	0.050	0.060	0.045	0.325	0.325	0.325
21:00	0.133	0.131	0.134	0.050	0.060	0.045	0.249	0.249	0.249
22:00	0.133	0.131	0.134	0.050	0.060	0.045	0.249	0.249	0.249
23:00	0.133	0.131	0.134	0.050	0.060	0.045	0.249	0.249	0.249
24:00	0.133	0.131	0.134	0.050	0.060	0.045	0.249	0.249	0.249

F Threshold Installation Capacities and Load Scaling Functions

Table A.11: Los Angeles; BA Climate Zone: Hot-Dry, IECC: 3B

Variable	Units	Small	Midsize	Large
Roof Area	m^2	93.7	187.4	281.2
Usable Roof Area	m^2	24.4	48.7	73.1
Annual Average Daily Load	kWh	11.13	21.52	32.17
Daily Average Solar PV Generation (Practical)	kWh	22.08	44.16	66.24
Maximum Unrestricted Capacity, $\bar{k}$	kW	4.98	9.95	14.93
Threshold Capacity, $k(\bar{k})$	kW	2.51	4.85	7.25
Load Scaling Factor, β	#	0.52	1.00	1.49

Table A.12: Las Vegas; BA Climate Zone: Hot-Dry, IECC: 3B

Variable	Units	Small	Midsize	Large
Roof Area	m^2	93.7	187.4	281.2
Usable Roof Area	m^2	24.4	48.7	73.1
Annual Average Daily Load	kWh	14.53	29.94	50.17
Daily Average Solar PV Generation (Practical)	kWh	25.19	50.38	75.58
Maximum Unrestricted Capacity, $\bar{k}$	kW	4.42	8.83	13.25
Threshold Capacity, $k(\bar{k})$	kW	2.91	5.59	10.03
Load Scaling Factor, β	#	0.49	1.00	1.68

Table A.13: Honolulu; BA Climate Zone: Hot-Humid, IECC: 1A

Variable	Units	Small	Midsize	Large
Roof Area	m^2	94.8	189.6	284.3
Usable Roof Area	m^2	24.6	49.3	73.9
Annual Average Daily Load	kWh	20.58	38.06	67.19
Daily Average Solar PV Generation (Practical)	kWh	22.27	44.56	66.83
Maximum Unrestricted Capacity, $\bar{k}$	kW	5.09	10.18	15.27
Threshold Capacity, $k(\bar{k})$	kW	4.7	8.69	15.27
Load Scaling Factor, β	#	0.54	1.00	1.77

G Optimal Installation Capacities – Additional Cases

G.1 Los Angeles, California

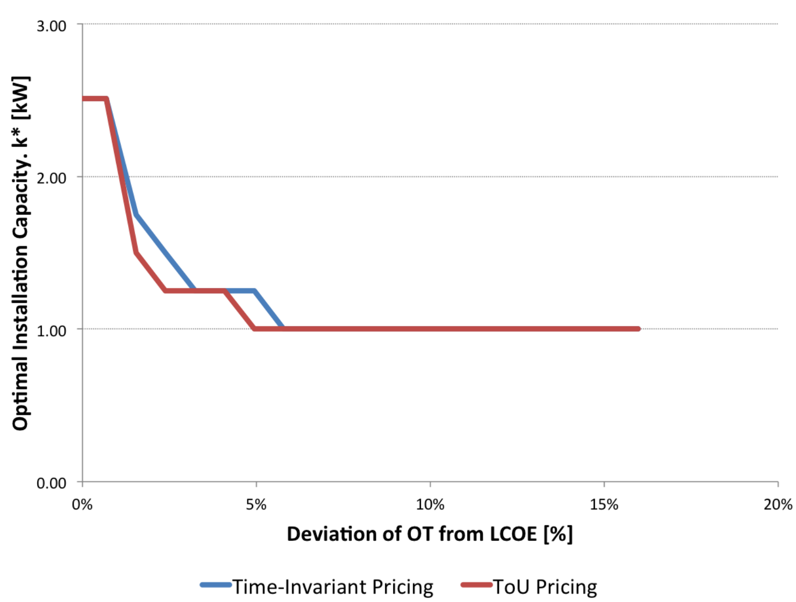

Figure 12: Optimal size of the residential solar system for a small house, in Los Angeles as a function of percentage difference from LCOE.

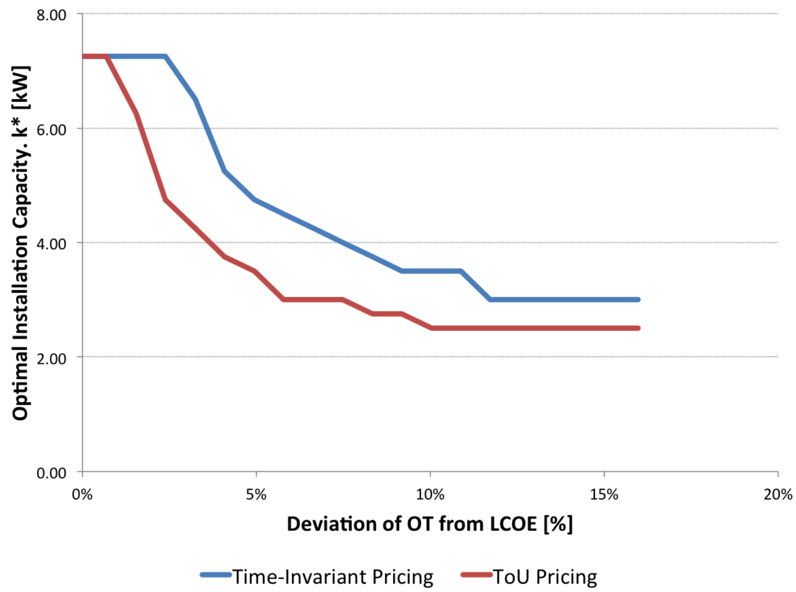

Figure 13: Optimal size of the residential solar system for a large house, in Los Angeles as a function of percentage difference from LCOE.

G.2 Las Vegas, Nevada

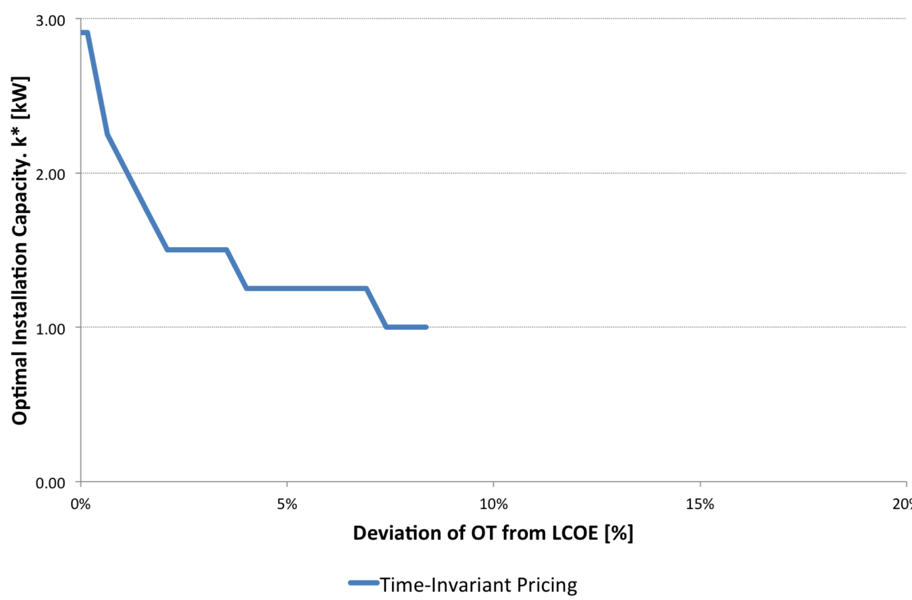

Figure 14: Optimal size of the residential solar system for a small house, in Las Vegas as a function of percentage difference from LCOE.

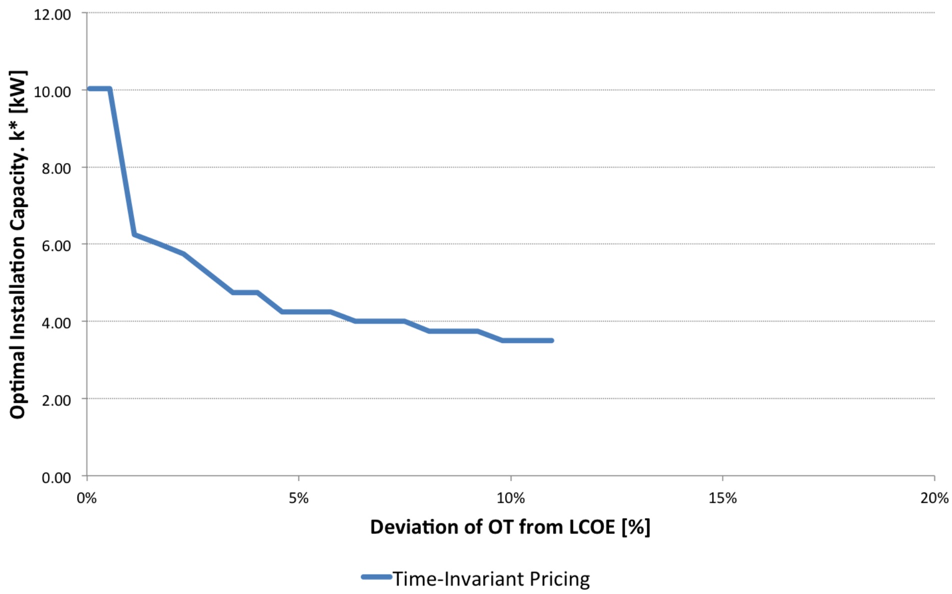

Figure 15: Optimal size of the residential solar system for a large house, in Las Vegas as a function of percentage difference from LCOE.

G.3 Honolulu, Hawaii

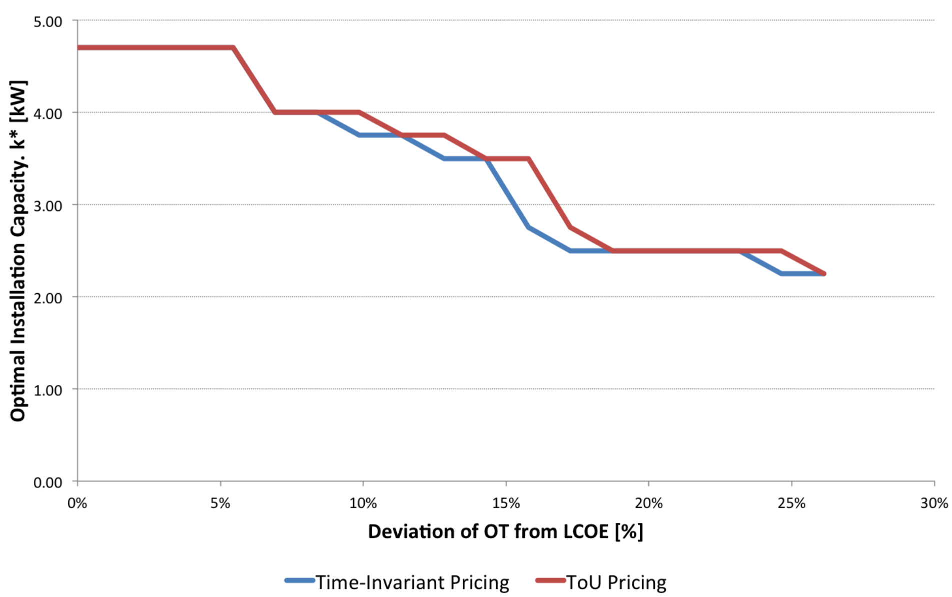

Figure 16: Optimal size of the residential solar system for a small house, in Honolulu as a function of percentage difference from LCOE.

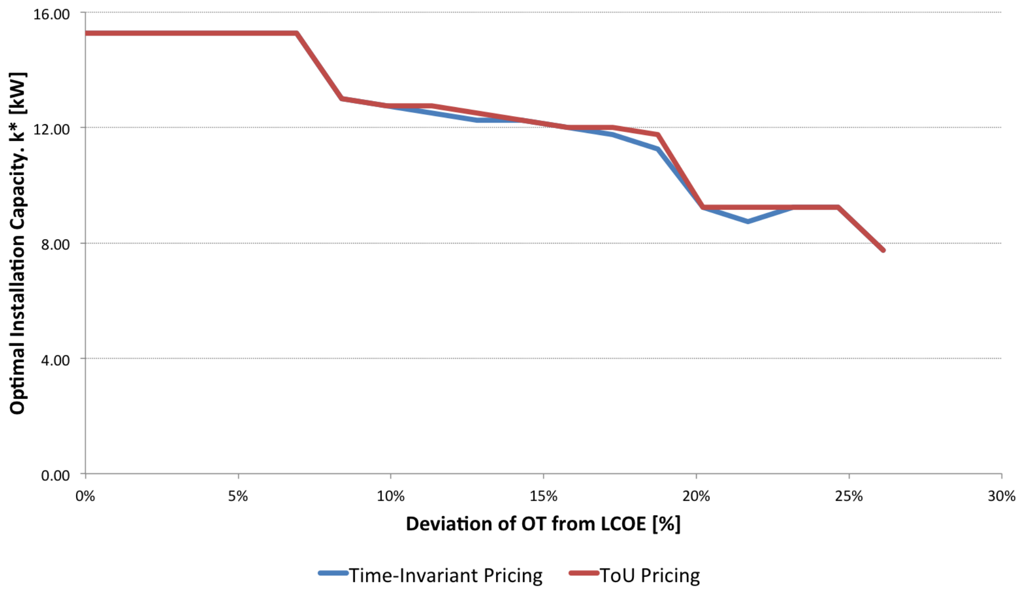

Figure 17: Optimal size of the residential solar system for a large house, in Honolulu as a function of percentage difference from LCOE.

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