Title

Uncertainties in the Value of Bill Savings from Behind-the-Meter, Residential Photovoltaic Systems: The Roles of Electricity Market Conditions, Retail Rate Design, and Net Metering

Author
Darghouth, Naim Richard

Publication Date
2013

Peer reviewed|Thesis/dissertation

Uncertainties in the Value of Bill Savings from Behind-the-Meter, Residential Photovoltaic Systems: The Roles of Electricity Market Conditions, Retail Rate Design, and Net Metering

by

Naïm Richard Darghouth

A dissertation submitted in partial satisfaction
of the requirements for the degree of

Doctor of Philosophy

in

Energy and Resources

in the

Graduate Division

of the

University of California, Berkeley

Committee in charge:

Professor Severin Borenstein, Chair
Dr. Ryan H. Wiser
Professor Daniel M. Kammen
Professor Lee S. Friedman

Spring 2013

Uncertainties in the Value of Bill Savings from Behind-the-Meter, Residential Photovoltaic Systems: The Roles of Electricity Market Conditions, Retail Rate Design, and Net Metering

by

Naïm Richard Darghouth

Abstract

Uncertainties in the Value of Bill Savings from Behind-the-Meter, Residential Photovoltaic Systems: The Roles of Electricity Market Conditions, Retail Rate Design, and Net Metering

by

Naïm Richard Darghouth

Doctor of Philosophy in Energy and Resources

University of California, Berkeley

Professor Severin Borenstein, Chair

Net metering has become a widespread policy mechanism in the U.S. for supporting customer adoption of distributed photovoltaics (PV), allowing customers with PV systems to reduce their electric bills by offsetting their consumption with PV generation, independent of the timing of the generation relative to consumption. Although net metering is one of the principal drivers for the residential PV market in the U.S., the academic literature on this policy has been sparse and this dissertation contributes to this emerging body of literature.

This dissertation explores the linkages between the availability of net metering, wholesale electricity market conditions, retail rates, and the residential bill savings from behind-the-meter PV systems. First, I examine the value of the bill savings that customers receive under net metering and alternatives to net metering, and the associated role of retail rate design, based on *current* rates and a sample of approximately two hundred residential customers of California's two largest electric utilities. I find that the bill savings per kWh of PV electricity generated varies greatly, largely attributable to the increasing block structure of the California utilities' residential retail rates. I also find that net metering provides significantly greater bill savings than alternative compensation mechanisms based on avoided costs. However, retail electricity rates may shift as wholesale electricity market conditions change.

I then investigate a potential change in market conditions – increased solar PV penetrations – on wholesale prices in the short-term based on the merit-order effect. This demonstrates the potential price effects of changes in market conditions, but also points to a number of methodological shortcomings of this method, motivating my usage of a long-term capacity investment and economic dispatch model to examine wholesale price effects of various wholesale market scenarios in the subsequent analysis. By developing three types of retail rates (a flat rate, a time-of-use rate, and real-time pricing) from these wholesale price profiles, I examine bill savings from PV generation for the ten wholesale market scenarios under net metering and an alternative to net metering where hourly excess PV generation is compensated at the wholesale price. Most generally, I challenge the common assertion that PV compensation is likely to stay constant (or rise) due to constant (or rising) retail rates, and find that future electricity market scenarios can drive substantial changes in residential retail rates and that these changes, in concert with variations in retail rate structures and PV compensation mechanisms, interact to place substantial uncertainty on the future value of bill savings from residential PV.

Contents

List of Figures

List of Tables

Acknowledgments

I am extremely grateful and feel privileged to have had such a distinguished, dedicated, and helpful dissertation committee. I would like to sincerely thank Severin Borenstein, Ryan Wiser, Dan Kammen, and Lee Friedman.

I would also like to thank all who have provided comments and suggestions at all stages of the dissertation: particularly Galen Barbose, Andrew Mills, Meredith Fowlie, Marco Nicolosi, Changui Dong, the reviewers of my reports and article, and the funders of my work.

There are a number of people in my life who have been pillars of support and encouragement throughout this long process. Thanks to my parents and sister for unconditionally being there for me, Prithi for always believing in me, and my close friends (Andrew, Buford, Cliff, Cyrus, Dano, David, Jo, and Kofi) who have been brothers to me. I am unbelievably lucky to have had all these people in my life during the process of getting my PhD.

Chapter 1 INTRODUCTION

Efforts to reduce greenhouse gas (GHG) emissions so that we can meet climate stabilization levels will require massive and multidisciplinary efforts from several fronts (IPCC, 2007). In the electricity sector, other than reducing consumption, replacing fossil fuel generation with renewable electricity generation is one of the most promising options to reach such a goal (Williams et al., 2012). Although reducing GHGs in the electricity sector may be more effective through a general carbon policy rather than direct renewables support, direct support for renewables has thus far been the principal driver for renewables growth (Mitchell et al., 2011). Whereas theoretically, a carbon policy may be more efficient to reduce GHG emissions in the electricity sector than renewable energy support (Palmer et al., 2011), a federal carbon policy has proven to be difficult to implement, for political reasons, in the US (Rabe, 2007). In Europe, legislation often led to concurrent carbon policy and renewable policy (Tsao et al., 2011), though thus far direct renewables support has provided the majority of incentives for the sector. Direct support for renewables has been justified by motivations other than GHG emission reductions: energy security or independence, local air quality issues, learning effects leading to future cost reductions, and economic development and jobs (Duke and Kammen, 1999; Goldemberg, 2004; IPCC, 2007; Fouquet and Johansson, 2008; Fischer and Preonas, 2010; Müller et al., 2011); however, evidence would suggest that some of these are sometimes overstated (Borenstein, 2012).

Renewables support can be classified either as push policies or pull policies (Loiter and Norberg-Bohm, 1999; Bürer and Wüstenhagen, 2009). Technology push policies tend to develop new markets through research and development, and innovation (Hoffert et al., 2002; Klaassen et al., 2005). Though billions of research dollars have been poured into renewable energy research in the last three decades, the US has historically underinvested in energy research and development relative to gross domestic product (Margolis and Kammen, 1999; Nemet and Kammen, 2007). Market pull policies involve methods to grow the market size, often through subsidies that lower the costs of renewables, mandates that require a minimum level of renewable penetration, or feed-in tariffs (FiTs) that ensure a compensation level for renewable generation over a fixed period (Jacobsson and Bergek, 2004; Fouquet and Johansson, 2008; Schmalensee, 2012). Often, the underlying rationale for market pull policies is that by increasing cumulative capacity for renewables, the industry would benefit from learning-by-doing and economies of scale (Duke and Kammen, 1999; Menanteau et al., 2003; Fischedick et al., 2011). The renewable subsidies most often discussed in the literature are feed-in-tariffs versus renewable portfolio standards (or renewable targets). A rich literature has discussed tensions between the two policies, and many have considered their cost-effectiveness and efficiency at lowering GHG emissions (Menanteau et al., 2003; Lauber, 2004; Mitchell et al., 2006; Ringel, 2006; Finon and Perez, 2007; Lipp, 2007; Midttun and Gautesen, 2007; Butler and Neuhoff, 2008; Yamamoto, 2012). In the US, rebates for renewable energy, such as the investment tax credit or the many state rebate programs, are more common than feed-in tariffs, and provide upfront subsidies to reduce the capital costs of renewable energy investments. To a lesser extent, a number of states instead provide performance-based incentives, which are not dependent on the upfront cost or capacity, but instead on the generation levels of the renewable energy project.

In addition to these explicit forms of renewable energy support, there are also implicit support mechanisms, most notably net metering, which provides billing credits for PV generation at the customer's underlying retail rate. Net metering policies are instituted in 43 states, as of April 2013 (DSIRE, 2013). It is the principal mechanism in which behind the meter PV owners are compensated for their PV generation in these states. The residential PV market in the US is driven by net metering policies and the underlying retail rates (Denholm et al., 2009). Without net-metering, it's likely that the US would have a significantly smaller market (Duke et al. 2005). Though literature has extensively covered the effectiveness and dynamics of FITs and RPS, there is much less literature on one of the principal drivers of the residential PV market in US: retail rates and net metering. Given that net metering drives the residential PV market, along with other federal and state policies, and though the trade literature has analyzed some of the more contentious issues related to net metering (E3 2010; IREC 2010; IREC Freeing the grid 2012;), there are surprisingly few academic analyses of net metering (Duke et al., 2005; Borenstein, 2008; Mills et al., 2008).

In this dissertation, I contribute to this emerging literature, and am specifically interested in the private customer value of behind-the-meter PV generation, as potential customers most often will consider the value of avoided electricity when considering whether to invest in the PV system. Value of bill savings determines the customer's rate of return on their investment, and though customers can consider other non-quantifiable factors, particularly among early adopters (Faiers and Neame, 2006), economic viability drives the residential PV market. This dissertation unravels the connections between retail rates and net metering, using the more complex residential rates in CA as a case study, and most importantly is the *first known effort* to understand and quantify the connections between wholesale market conditions, retail rates, and the value to residential PV customers, contributing to the literature on support for renewables.

The remaining portion of the introduction chapter is organized as follows. First, I introduce a couple of the core concepts relevant to this dissertation regarding electricity markets and retail electricity rate design. In section 1.1.1, I introduce the basics of electricity markets in the context of restructuring and deregulation, with a particular focus on how low marginal cost variable generation, such as solar or wind power, interact with wholesale markets. Section 1.1.2 presents underlying motivations for retail electricity pricing and some of the more common rate structures offered by utilities today as well as more complex rates which are dependent on market conditions. Understanding these concepts allow for a more complete understanding of the dynamics between wholesale markets, retail electricity rates, and bill savings from behind-the-meter solar discussed in the subsequent chapters. The final section is an outline and roadmap for the entire dissertation, which introduces each of the remaining chapters and their respective contributions to the dissertation as a whole.

1.1 Background and relevant themes

1.1.1 Electricity markets and impacts of renewable generation on wholesale markets

The structures of electricity markets have changed significantly in the past twenty years. In the past, electric utilities were vertically integrated, with a single company owning generation, transmission, and distribution infrastructure, and hence there was no independent wholesale electricity market. Public or investor owned utilities entered a regulatory contract to (a) provide electricity services to retail customers, and (b) develop generation capacity to provide for contingencies associated with quality of service. In exchange, the utilities were guaranteed rate of return on their investments.

However, in the early to mid-1990s, the federal government, as well as powerful players in the private sector, began to push for deregulation in the electricity market, following the deregulation of several other sectors in the 1980s. FERC passed order 888 in 1996, whose goal was “to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers” (FERC, 1996). Though early deregulation efforts ran into implementation difficulties (most famously California's failed deregulation experience from 1998 to 2001), regulators adapted market design to find a balance between full regulation and full deregulation. This allows for electricity to be traded in wholesale markets, but reduces the risks of sellers exercising market power. The implementation details for wholesale electricity markets vary by region, and markets are often managed by the regional independent system operator.

California's current energy market, for example, allows suppliers to bid in day-ahead and real-time markets, in addition to having the option to enter short- and long-term contracts with utilities in the integrated forward market. The day ahead-market is based on load forecasts, and the real-time market is designed to rebalance any differences from that forecast. A generator can bid a monotonically increasing, stepwise bid into both the day-ahead and real-time market the amount to be delivered (or online for reserve markets) at a specific location and time. When each of the generators bids is added to the bid stack, this creates a supply curve for electricity generation in the balancing area. A corresponding load curve is constructed from the bids submitted by electricity customers (which can include utilities, industrial customers, or traders) which are based on their willingness to pay for a set amount of electricity at a given location and time. Many times they submit demand bids as “self-scheduled”, where they just give the quantity they need, and the California Independent System Operator (CAISO) arranges it at least cost. The CAISO uses a full network model to optimize dispatch and determine the market clearing price at every given location for that hour (or 5 minute period in the RTM).

In addition to coordinating electricity generation, the CAISO also manages ancillary services, which ensure that there is sufficient slack in capacity to avoid blackouts in case of contingencies. Similar to the energy bids, generators can a submit bids to provide regulation up, regulation down, spinning and non-spinning reserves to the day-ahead and real-time markets.

More generically, the electricity wholesale market is intended to send long term price signals to generators when capacity needs to be built. During times of peak load, when the market for electricity becomes tighter, prices rise, increasing profits and incentives for capacity expansion in the longer term. In equilibrium, the price differential with marginal costs during these peak times are equal to the value of an additional unit of capacity (Borenstein, 2008). When capacity needs to be built to meet peak load (i.e. peak load rises), this price differential increases to a level greater than the cost of adding one unit of capacity, leading to new generation being built.[1] The levelized total revenue received by each plant beyond its marginal costs over its lifetime should be equal to the plant's fixed costs.

If all customers were exposed to the wholesale market prices, demand would adjust depending on the elasticity of demand. However, only some industrial customers have retail rates tied to the wholesale market, while the rest have static prices, leading to over-capacity in the market. This leads to an effective elasticity of demand which is lower than the customer's real demand elasticity. In addition to implementing dynamic retail rates as a mechanism to enable behavior closer to true demand elasticity, demand response programs on peak days can also approximate the customers' actual elasticity of demand. Demand response reduces electricity consumption, sometimes through automated systems, on peak days which reduces price spikes in the short term, and reduces the need for capacity expansion in the longer term.

Thus far, my discussion of electricity markets has been based on the assumption that generation is dispatchable. In the following paragraphs, I will be looking at how electricity produced from solar, which is non-dispatchable, intermittent, and has close to zero marginal costs, interacts with electricity markets.

Reaching an equilibrium state, where all profitable additional capacity is built, never occurs as market characteristics change continuously and there is always error in long-term market forecasts. Additional capacity often takes years to permit, plan, and build. However, even though electricity markets are dynamic, they adapt to larger structural changes in the long term (i.e. high penetration of intermittent generation such as from solar).

In the short term, system operators integrate the aggregate PV generation in their balancing area. Though the general profile of PV production is deterministic (in clear weather, the profile can be forecast perfectly), the output of a PV system can drop to almost zero when a cloud passes overhead in very short time spans. When aggregated, PV systems in a balancing area of diverse microclimates will tend to smooth the variability (Mills and Wiser, 2010). Even when smoothed due to geographic diversity, the short-term variability must be met with reserve generation to compensate for fluctuations in aggregate PV generation. This is necessary in order for supply to continuously match load and avoid frequency distortions. These reserves need to have ramp rates on the order of minutes, and only very flexible generators such as combustion turbines can fill this role. The additional costs to have these generators online are the short-term integration costs of solar.

[1] This is true under an energy-only market with no price caps. Many electricity market designs do not allow prices to climb to such high levels, but others have mechanisms like a parallel market to allow generators which provide capacity to recover their fixed costs. The payments to those generators, however, should be the same in both market designs.

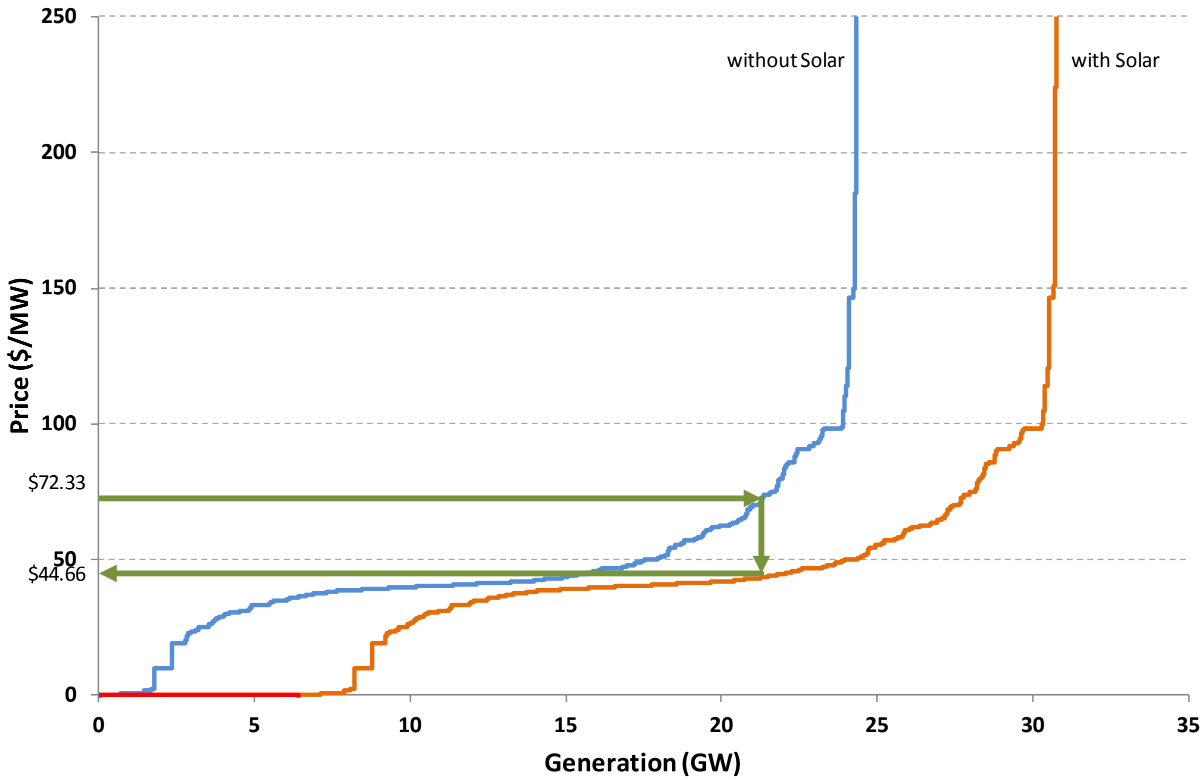

Figure 1. Impact of simulated PV generation on energy bids in the CAISO day-ahead market, September 23, 2009 at 4 pm, with 6.4 GW of solar generation.

Solar generation is bid into the day-ahead market, using solar production forecasts. Since the marginal cost of generation of solar is zero, it would likely bid at an inframarginal[2] price (effectively, a self-scheduled bid). This effectively shifts the supply curve out to the right, and reduces the market clearing price – assuming a non-zero slope around the point of intersection between supply and demand. If the slope of the supply curve at the point of intersection with the demand curve is steep, the price difference could be significant. In Figure 1 is an example of a supply curve from the CAISO day-ahead market on a high demand day, September 23, 2009 at 4 pm. As shown in the figure, were solar to produce 6.4 GW, the resulting market clearing price would decrease from $72/MWh to $45/MWh.

The price change for a specific hour observed in Figure 1 can be replicated for each hour of the day, with different bid curves and PV generation levels, to find the daily price profile. Figure 2 shows the daily price profile with and without solar for the same day. Assuming a static mix of electricity generation technologies, this would result in a reduction in prices during times when solar generation is highest – effectively shifting the peak time from approximately 12-6 pm to 3-9 pm. This outcome is a result of the *merit-order effect*.

[2] Implying below marginal costs.

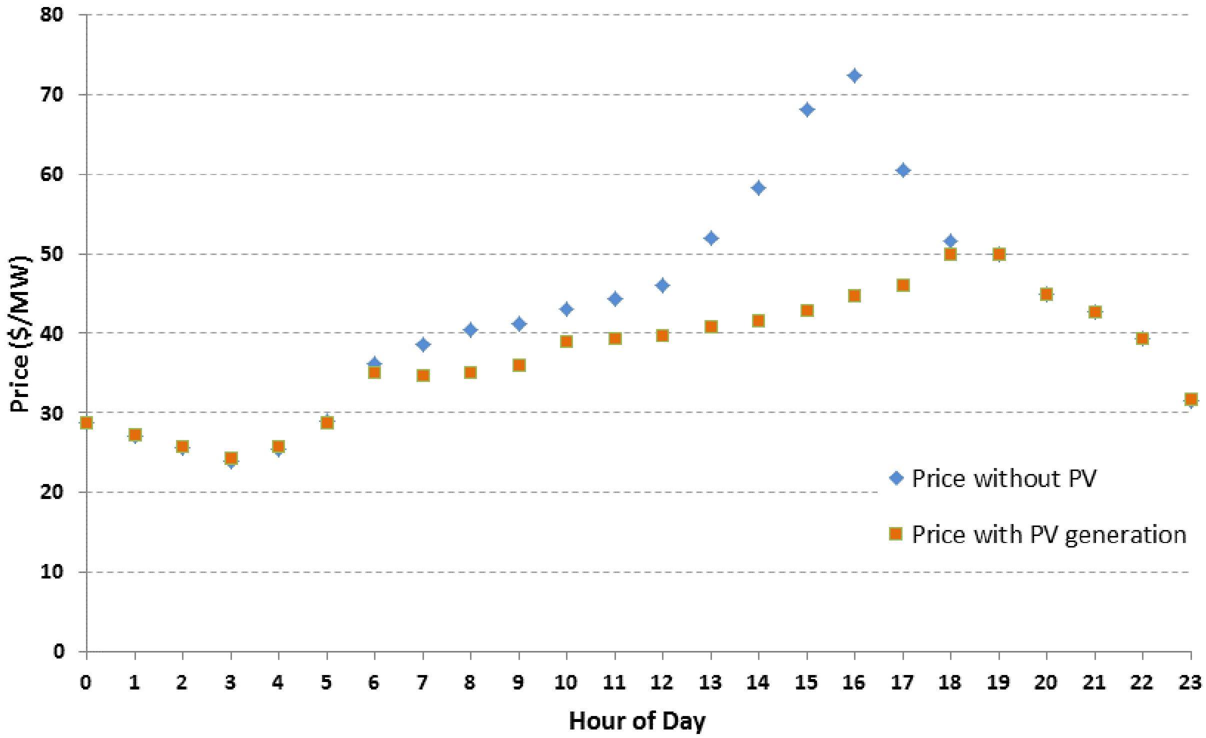

Figure 2. Impact of simulated PV generation on prices in the CAISO day-ahead market, September 23, 2009.

In the longer term, when capacity has been built to account for higher peak load and higher solar penetration, one would expect to have a different mix of generation, given the flexibility needed to balance the variability from PV. At low penetrations, solar generates during times of summer afternoon peak load (Denholm and Margolis, 2007) and hence supply curves will shift out during peak hours, leading to lower peak market prices as penetrations increase. If sufficient solar capacity is built to displace some of the lower marginal cost baseload generation at any time, this would lead to decreased incentives for construction of new high capital cost baseload capacity, which need a high capacity factor to stay profitable, and more flexible mid-priced generation, such as a combined cycle gas turbine (CCGT), would replace some baseload generation as older baseload plants retire. In the long run, this would lead to higher prices during off-peak times (since the marginal costs of electricity for CCGT plants are greater than those for baseload plants). The dynamics are further complicated if demand response or storage is added. To most accurately simulate how capacity additions would impact the daily price profiles of electricity, a long-term capacity investment model could be used, such as the model used and introduced in Chapter 4.

Previous work has explored the short term and long term wholesale price effects of intermittent generation (e.g.. Lamont, 2008; Sáenz de Miera et al., 2008; Sensfuß et al., 2008). Sensfuß et al. (2008) analyze the short-term impacts of wind generation on simulated electricity spot prices in Germany, using the merit-order effect. In Sensfuß et al. (2008), the demand curve is shifted in by the amount of solar generation, to create a residual demand curve. This approach finds an equivalent price to when the supply curve is shifted to the right by the amount of renewable generation. The price effects of “must-take” zero marginal cost generation depend on the slope of the generation supply curve at the intersection of demand. The steeper the supply curve, the larger the price effect of shifting the demand to the left. The authors conduct a sensitivity analysis, to understand how various scenarios would change the generation mix and impact the supply curve in the long term. Changes in the supply curve result in changes in the price effects of zero marginal cost generation. The principal limitation to the merit-order method employed by Sensfuß et al. is that it doesn't take into account any generation mix changes, and hence is a very short-term based analysis. Sàenz et al. (2008) also analyze the price effects of wind generation in wholesale markets. Instead of using supply and residual demand curves, Sàenz et al. use screening curves to determine wholesale price effects of wind generation (a method previously used in Kelly and Weinberg (1993) and Stoft (2002), among others), but considers longer-term impacts on prices as influenced by capacity expansion decisions. Again, by treating intermittent generation as negative loads (i.e. shifting the demand curve to the left), the residual load duration curve can be constructed and matched with the capacity cost curve for available generators to determine the optimal mix of generation with wind. Comparing the optimal mix with and without wind generation allows for the calculation of average price differences. Both these methods are useful to give approximate wholesale price impacts for intermittent generation (in the short term and longer term, respectively), but do not take into account the operational constraints of generators (such as ramp rates or availability) or generator profitability considerations. Lamont (2008) augments the screening curve approach by creating a framework in which the overall operation costs are minimized, given generator constraints. This analysis allows for the computation of marginal value of intermittent electricity generation, which is found to decrease with increasing penetration. Mills and Wiser (2012) use a capacity investment and dispatch model to quantify the value of solar and wind electricity generation at increased PV, concentrated solar power (CSP) with and without storage, and wind penetrations. Among others, their findings include that at low penetrations, solar (PV and CSP) has high value, but as PV and CSP without storage levels increase, the value drops rapidly. The model used by Mills and Wiser is subsequently used in Chapter 4 of this dissertation, and is described in greater detail in section 4.2.3.

1.1.2 Retail Electricity Pricing

Retail electricity rates must enable the recovery of the costs the utility incurs to generate and deliver electricity to the customer. Typically, even in a deregulated market, only a portion of electricity delivered to retail customers is purchased on the wholesale market. Most of the remaining electricity delivered to customers by utilities is either generated by generation capacity owned by the utility (utility-owned generation or UOG) or purchased via bilateral agreements with specific generators. When energy prices are equal to the marginal cost of the most expensive generator at all times, utilities also need to recover capacity cost relating to maintaining resource adequacy at all times, which is also bundled into retail rates. Besides the cost of generating electricity and ensuring reliability, there are also costs related to transmitting that electricity from generators to load centers and distributing the electricity within the load centers to the individual customers, in addition to any other fixed costs, all which need to be recovered through retail rates. Finally, sometimes retail rates recover costs related to cross-subsidies from one customer group to another. For example, California offers subsidized rates for low-income residential customers and these subsidies are recovered through the rates of the non-participants in the low-priced programs. In the following paragraphs, I will introduce what objectives rates may have, in addition to recovering the utilities' costs, as well as describe some specific issues that have arisen in the last decades relating to the economic efficiency of retail rates.

Regulators strive to manage retail electricity rates to achieve both economic and social goals. The process of setting rates that are acceptable to both utilities and consumers is complex, and often involves as much political economy as it does economics. Many commodities are priced via market mechanisms, and reflect the willingness to pay for a specific commodity and the costs that sellers face to produce that commodity. Retail electricity, however, is government regulated (to varying degrees as prescribed by local legislation), and is fundamentally different than many other commodities for two reasons. First, the service that electricity provides has often been treated more as a right than a commodity. Reliable access to electricity is for most a necessity in the US – a requirement for normal functioning of society. If electricity is withheld from consumers, due to emergency situations or exceptional market conditions, the economic impact is enormous (Koonce et al. 2008). Second, electric utilities have historically been considered natural monopolies. Since having more than one set of transmission and distribution (T&D) networks is an inefficient allocation of resources, a single utility is responsible for delivering electricity, providing transmission and distribution services, and sometimes wholesale electricity, to a specific service territory. These two factors have led to government regulation of electric utilities. It is the responsibility of state and federal governments to ensure that all customers are able to purchase electricity from their assigned electric utility in any quantity and at any time with high standards of quality of service, choosing from a variety of retail rate structures considered to be "fair" for both the customers and the utility.

In Bonbright's seminal book, *Principles of Public Utility Rates*, he cites the following as the goals of utility ratemaking. Paraphrased and condensed, Bonbright states that retail rates set must:

- be simple to understand, unambiguous, and acceptable to the public;
- lead to stable revenues sufficient for utilities to cover their costs plus a fair rate of return;
- be stable and predictable themselves;
- be set in such a way to minimize cross-subsidies between customer types and without discriminating against a specific type of customer; and,
- be economically efficient, to minimize wasteful use of electricity.

Economic efficiency has become an increasingly critical objective of retail electricity rates since the 1970s, as a result of a gain in consciousness on issues of efficiency due to the energy crises, and a desire for greater levels of competitiveness and cost-savings. Though increasing economic efficiency of rates can be at odds with some of the other objectives stated above, it has been the focus of many recent utility rate cases. In the rest of this section, I will outline what is meant by economic efficiency of retail electricity rates, what efficient rates can imply, and what strategies have been proposed to make rates more efficient, in addition to discussing rates currently available.

Classical economics dictates that retail electricity rates should be set to maximize societal gain, encouraging efficient allocation of electricity resources. As with any price, retail electricity rates should help the consumer determine what quantity of electricity to purchase, and should also represent the actual costs of generating electricity. Since electricity demand fluctuates constantly, as does electricity generation availability, marginal costs of supplying electricity to the customer also change constantly and are dependent on a number of exogenous factors, including weather and generation outages. Setting marginal price to this varying marginal cost plus a fixed annual charge to recover utility costs is Pareto efficient, as long as the fixed charge does not cause any potential consumers not to consume at all (Feldstein, 1972).

However, the default electricity rate in the United States, especially for residential customers, has traditionally been a flat rate – a rate that is not a function of the time at which the electricity is consumed and with little or no fixed customer charges. The flat rate is typically the sum of the aggregated, long-term average of wholesale electricity prices faced by the consumers, the T&D congestion and infrastructure costs associated with delivering electricity from the generator to the customer, as well as administrative costs related to metering, billing, etc. – all recovered through a single volumetric charge. The metering technology necessary to implement such a rate is simple; basic electricity meters which record electricity consumption without keeping track of when the electricity was consumed are sufficient. Flat rates also meet other criteria noted by Bonbright, such as simplicity, stability, and predictability. Nonetheless, during periods of low demand, this average flat rate may be higher than the marginal cost of production, and during periods of peak demand, the flat rate for electricity will be lower than its marginal costs. As with any commodity, if at any given time, the retail rate is lower than the marginal cost of production, the quantity consumed will be greater than the optimal amount, leading in the short term to the suppliers undergoing a loss greater in value than the gain that the electricity customers undergoes (the difference being the deadweight loss). There is also a deadweight loss when the retail rate is higher than marginal costs. In the long term, pricing consumers at a rate lower than marginal costs during peak times leads to the construction of extra peak capacity – an inefficient allocation of resources.

Further, some utilities implement increasing block pricing (IBP) concurrently to the flat rate. Under IBP, the marginal rate faced by the consumer increases in steps with increasing consumption. This is intended to encourage customers to consume less electricity, hence reducing greenhouse gas emissions and, if these decreases are coincident with system-level peak demand, reducing long-term capacity expansion[3]. IBP also ensures that all customers have access to a minimum amount of electricity per month at low rates. However, the economic justification for IBP is weak, and hence economic efficiency is compromised by other goals.

As discussed in section 4.2.2, capacity costs are also time-dependent (i.e. they are highest during peak generation times). Most commercial and industrial rates attempt to recover capacity costs based on the customer's peak demand in a given period. Almost all residential rates in the U.S., as they are structured today, recover capacity costs through a single volumetric charge over all consumption. Although the commercial and industrial rate structures tend to distort prices less than residential rate structures, many base their demand charge on the customer's peak load at

---

[3] Evidence suggests, however, that customers do not reduce overall consumption with increasing block pricing (Ito, 2012).

any hour, whereas this may not be relevant to capacity costs, if this is during the middle of the night, when system load is low, for example. For residential rate structures that recover capacity costs through a single volumetric charge, price signals are further distorted, making rates much lower than costs during hours of peak load, and higher than costs of generation at all other hours. When the wholesale electricity prices are based on an energy-only market, the capacity costs are integrated in the wholesale prices, and hence retail rates.

There are options for retail rate structures more efficient than the flat rate, and some have been proposed since the 1970s. Though these rates do not always fully reflect the real-time changes in marginal costs of electricity, they have some element of signaling to the consumer at times when prices tend to be high or low. The consumer bears at least some of the real costs of producing/procuring electricity, leading them to adjust their consumption levels (potentially offsetting some capacity expansion in the long run). In addition, metering technologies are no longer an economic barrier to implementation, as advanced meters have become more affordable. The most common of these retail electricity rates are outlined below.

Time-of-Use Rates. As opposed to the flat rate, the time-of-use (TOU) rate is dependent on *when* the customer purchases the electricity from the supplier. Volumetric charges vary according to both season and time of day. These charges are higher at times when marginal costs of generating and delivering electricity are higher on average, and the charges are lower when marginal costs are lower on average, which send more accurate price signals to consumer than the flat rate. Most commonly, higher rates are set during times of peak demand (i.e. mid-day to early evening weekdays) and lower rates are set during off-peak times (i.e. weekday mornings, nights, and at all times weekends). Though TOU rates are time-based, they are static; they do not reflect the continuously changing and somewhat unpredictable time-varying marginal cost of production. TOU rates are equivalent on days with exceptionally high prices and on days with average prices; customers do not have any incentive to reduce their consumption on high-price days, leading to the same types of inefficiencies than with the flat rate, and with questionable gains in efficiency compared with the flat rate (Borenstein 2005). While the metering technology needed to implement TOU rates must be able to differentiate between peak and off-peak periods, hourly recordings are not necessary.

Dynamic Rates. Dynamic rates encompass any retail electricity rate which changes to reflect market conditions. Real-time pricing (RTP) is a retail rate option in which volumetric charges change on an hourly or sub-hourly basis, dependent on the marginal cost of procuring electricity at that time. These rates can be set up to a day in advance, and rely on market forecasts to estimate the generation portion of electricity rates. Another commonly cited option for dynamic pricing is critical peak pricing (CPP). With CPP, rates are static throughout the year (either with a flat or TOU rate) except for a predetermined number of higher-priced, critical peak days. These days are often announced a day ahead by the utilities, and are chosen using day-ahead price forecasts for the market price of electricity generation.

The benefits of dynamic pricing include increased market efficiency, reducing cross-subsidization, and reducing opportunities for sellers to exercise market power. Dynamic rates are more efficient than static rates because they signal high marginal costs to the consumer, resulting in a transfer in profits from the consumer to the seller in the short term, and reduced need for capacity expansion in the longer term (Borenstein, 2005a; Faruqui et al., 2009; Braithwait, 2010;

Faruqui and Sergici, 2010). When rates are static, the group of customers who consume most of their electricity during periods of lower price are effectively subsidizing the rates for the group who consume more during periods of higher cost. With dynamic rates, these cross-subsidies are reduced, since customers face rates that are closer to the actual cost of providing them with electricity, instead of being averaged over larger time periods. Another benefit to dynamic pricing is that sellers in a competitive market are less likely to be able to exercise market power (Borenstein, 2011). With static retail rates, a power producer on the margin can withhold some capacity to create a shortage of supply, thereby raising the market price of electricity substantially and allowing for high profits on the electricity produced from the capacity not withheld. Exercising market power is facilitated when demand is inelastic, which is the case in the short term with static prices since buyers are not directly faced with the higher prices. With dynamic pricing, customers can adjust to high prices by reducing their consumption, thereby reducing the price. Therefore the incentive for a seller to exercise market power by withholding capacity is lower, since the impact on prices is lower.

RTP produces more temporal resolution in pricing than does CPP, and hence is more economically efficient. Also, the development of affordable "smart meters" has made RTP technically *and* economically feasible (Faruqui et al., 2009). However, RTP has run into a number of challenges. Consumers and regulators are worried that RTP will lead to price shocks, since customers could face extremely high prices at times, leading to unmanageably high bills for some months. When combined with forward contracts and other bill hedging instruments, however, RTP could also offer some level of certainty in future rates and avoidance of bill shock. (Borenstein 2006) Another concern is the complexity and stability of RTP. Some customers would have difficulty understanding their electricity rate structure and monthly bills, or may be with uncertain bills – not knowing how much they will spend on electricity on any given month because of factors not within their direct control.

Although time-varying rates usually signal to consumers general price trends, many times these rates are recovered only through volumetric charges alone. For example, the time-of-use rate provides general price signal to consumers by setting a higher price during hours where the cost of electricity has historically been high and lower prices during hours where the cost of electricity has been low. The rates in each period are volumetric charges and include a component to recover transmission and distribution costs, in addition to administrative and miscellaneous costs. Recovering fixed costs through volumetric rates distorts the price signals to customers; by increasing the marginal price to consumers, customers consume less than the optimal amount (assuming a negative slope on the customer's demand curve), and hence again leads to deadweight loss.

Two-part tariffs are an alternative rate structure to recovering costs through volumetric charges alone, and consist of a fixed customer charge that is typically independent of the amount of electricity consumed by the customer and a volumetric charge (Feldstein, 1972). The customer charge is meant to recover fixed costs that are not dependent on the amount of electricity consumed by the customer (e.g. metering costs are often independent of the amount of electricity consumed by a customer in a specific customer class). By recovering the fixed costs through a customer charge, the volumetric charges are lower and distort the price signal less than when the fixed costs are recovered through a volumetric charge. Even with a two-part tariff, however, when the energy charge is a (time-invariant) flat rate, customers still over-consume when the flat rate is less than marginal cost and under-consume when the flat rate is greater than marginal cost. In a deregulated electricity market, where utilities can purchase electricity on the wholesale market, an efficient rate is a real-time rate, which allows the customer's marginal rate to track the wholesale price, potentially changing every minute, in addition to a fixed portion allowing the utility to recover all of its costs. Though some have suggested that the fixed charge is the same for all (essentially, the cost of connecting a customer to the local distribution grid, as in Naughton (1982), for example), these transmission and distribution costs are not necessarily identical for all customers. Customers whose load is high during time of peak load in a distribution grid should contribute more towards the cost of the distribution network than customers whose load is low during those times. A similar argument can be made for transmission costs. Administrative and billing costs for utilities could be higher for rural customers than urban customers. However, as discussed earlier in this section, efficiency is only one of many goals of retail rates and an *efficiently* designed two-part tariff violates proposed objectives of retail rates since rates should be stable and predictable, and it would therefore be difficult for the public and regulators to accept such a two part tariff whose fixed costs vary substantially from one customer to the next.

Besides efficiency of retail rates, another contentious debate on retail rate design is related to the equity of rates and whether a group of customers is disproportionally impacted by a new rate structure or a change in rate levels. In particular, there has been some debate on changing from volumetric charges to two-part tariffs (Pearce and Harris, 2007). It can be argued that in many cases, an "efficient" two part tariff is not an equitable rate structure. As a utility switches from a volumetric rate to a two-part tariff, smaller consumers can end up paying a much higher average rate than large consumers. As smaller consumers tend to be poorer than larger consumers, such a two-part tariff would resemble a regressive tax, where the average rate reduces with increasing consumption (Feldstein, 1972). Some solutions have been proposed to rectify such inequity in rates, such as Friedman's Household On and Off Peak (HOOP) rates, where the customer charge is based on historical annual consumption or annual cost prior to switching to a HOOP rate and volumetric rates are set at the time-varying marginal cost (Friedman, 2012). Rates that take equity into consideration are also most probably creating inefficiencies and cross-subsidies from one group of customers to another; these cross-subsidies are a desired outcome in this case.[4] Often, the equity debate is confused with the status quo debate; advocate groups tend to react strongly in opposition to any major change in retail rate structures, particularly if a single group of customers is disproportionately impacted by that change, even if that change increases equity among customer groups. One example of this is solar advocates, who tend to resist any change in rates that have a negative impact on the economics of behind-the-meter solar, regardless of whether the change would make rates more equitable.

Another issue relating to retail rates that has been discussed is whether net metering should be continued as the principal compensation mechanism for behind-the-meter PV. Net-metered solar PV with a flat volumetric charge could lead to an increase in the flat volumetric rates for all as net metering reduces total retail sales and (a) does not enable the utility to recover its fixed

[4] This begs the question: should a redistribution of wealth be accomplished through electricity rates? Though this topic is beyond the scope of this dissertation, the answer lies in the political economy of the electricity market; essentially, rates have been set historically from political considerations rather than purely economic considerations, regardless of any potential negative impacts on societal well-being as a whole.

costs (particularly relating to the distribution grid), which could lead to a decline in quality of service, and (b) increases rates for all customers, with a disproportionate effect on non-PV owners, if the utility is "decoupled" from the amount of electricity it sells. In some scenarios, net-metered PV provides benefits to the grid, such as delayed investments in infrastructure upgrades or the displacement of expensive peaker plant generation, which would offset these negative impacts. But there are other scenarios where PV could potentially add to the costs (e.g. in a distribution grid with a very high penetration of PV, instead of reducing the peak load on the distribution network, PV generation could reverse the flow of electricity and lead to an opposite flow of electricity greater in magnitude than the previous peak load, which would increase the distribution investments needed rather than decrease them (Caamaño-Martín et al., 2008; Braun et al., 2012)). Though some may argue that net metering is an expensive policy to non-PV owner ratepayers, others argue that net metering has been an integral support policy for development of the PV market in the US. Net metering has been the main support policy, other than upfront cost incentives, for behind-the-meter PV. Changing rates to a two-part tariff with a uniform fixed fee, for example, would greatly reduce the value of bill savings from PV (see in section 4.4.2 later in this chapter). The risk of such a change in rates creates great uncertainty in the return on investment from PV for potential PV customers. Hence, given that net metering has been the PV compensation mechanism of choice in the US, one would expect that PV system owners and stakeholders resist changes in retail rates.

1.2 Dissertation outline

Residential behind-the-meter PV is predominantly compensated with net metering, which provides customers with PV bill credits for each unit of PV generation at the underlying retail rate. PV generation thus derives its value from the savings in the customer's electricity bills. The second chapter of the dissertation builds on existing literature by exploring how differences in rate structures affect the value of the bill savings provided through net metering, focusing on California as a case study. Understanding the interactions between retail rates, compensation mechanisms, and the value of bill savings is a crucial factor impacting the private customer economics of behind-the-meter PV. A number of studies, including Mills et al. (2008) and Borenstein (2007), have investigated bill savings from PV for different customer classes (e.g. commercial customers) or under different conditions (e.g. smaller PV systems), but this chapter focuses on residential customers using current rates in California and methods previously utilized in existing literature. Chapter 2 quantifies bill savings from PV with the prevailing flat rate, with increasing block pricing, for the two largest investor-owned utilities in California. It also explores some of the more efficient rates discussed in the section above and how these impact the value of bill savings from PV, with a particular focus on the time-of-use rates offered by the utilities (at the time of writing this dissertation, they did not offer real-time rates for residential customers). In addition, this chapter explores the potential impact on bill savings of replacing net metering and moving towards an avoided-cost compensation, to understand how large the "subsidy" associated with net metering is to PV owners, using three potential alternative compensation mechanisms all based on the same avoided-cost valuation. However, the focus of this chapter is on current rates, and hence this does not consider the impact of changes to wholesale markets or other rate structures. Changes in electricity market characteristics and retail rate structures could impact retail electricity rates (by way of changes to wholesale electricity price profiles) and bill savings from behind-the-meter, residential PV.

The third chapter of the dissertation provides an example of how changes in wholesale market characteristics – in this case higher PV penetrations – may impact wholesale price profiles (and hence retail electricity rates), and provides a motivation for further exploration of the impact of wholesale market changes on bill savings from PV, a topic explored in chapter 4. More specifically, short-term wholesale price impacts from higher levels of PV generation are examined via the merit-order effect. PV generation in any given hour effectively shifts the hourly electricity generation supply curve outwards, which reduces the marginal price of generation in the wholesale market (given the supply curve's positive slope). Using hourly generator and load bid data from the California Independent System Operator, hourly supply and demand curves were reconstructed for each hour, over a one year period in 2009-2010. The resulting wholesale price profiles could then be used to develop retail rates. However, though this method demonstrates that changes in wholesale market characteristics can have a sizeable impact on wholesale market prices (particularly their temporal profiles), a model that accounts for capacity expansion and operational constraints would more accurately portray future wholesale electricity price profiles and trends. This chapter examines the shortcomings of this method, and motivates the use of a more complex capacity expansion and dispatch model, which incorporates changes in the generation mix as well as operational constraints, in the following chapter of the dissertation.

The fourth chapter of the dissertation explores how potential changes in wholesale market characteristics could impact retail electricity rates, and the value of bill savings from behind-the-meter PV, by way of a simplified production-cost and capacity-expansion model to model hourly wholesale market prices from various electricity market scenarios. The scenarios include various levels of renewable and solar energy deployment, high and low natural gas prices, the possible introduction of carbon pricing, and greater or lesser reliance on utility-scale storage and demand response. Based on the hourly wholesale market prices calculated in the first step, I create three potential future retail rates for each electricity market scenario: flat, time-of-use, and real-time pricing. The rate levels and structures are created using standard rate design principles and assuming full cost recovery of variable and fixed costs. Finally, the value of bill savings from PV is calculated for a sample of residential customers by calculating their annual bill with and without PV generation, for each retail rate type and for each electricity market scenario. The bills with PV are calculated using two compensation mechanisms: net metering and a partial form of net metering. The literature has focused thus far on wholesale price effects of wholesale market conditions, but this work is the *first* known effort to extend the analysis to the retail level, and link the retail rate effects to the customer economics of behind-the-meter solar. In this chapter, I demonstrate that future electricity market scenarios, retail rate structures, and the availability of net metering can interact to greatly impact the future value of bill savings from residential PV.

Chapter 2 THE IMPACT OF RATE DESIGN AND NET METERING ON THE BILL SAVINGS FROM DISTRIBUTED PV FOR RESIDENTIAL CUSTOMERS IN CALIFORNIA

2.1 Introduction

Net metering has become a widespread policy in the U.S. for supporting distributed photovoltaics (PV) adoption.[5] Though specific design details vary, net metering allows customers with PV to reduce their electric bills by offsetting their consumption with PV generation, independent of the timing of the generation relative to consumption – in effect, compensating the PV generation at retail electricity rates (Rose et al., 2009).

Though net metering has played an important role in jump-starting the PV market in the U.S., challenges to net metering policies have emerged in a number of states and contexts, and alternative compensation methods are under consideration. Moreover, one inherent feature of net metering is that the value of the utility bill savings it provides to customers with PV depends heavily on the structure of the underlying retail electricity rate, as well as on the characteristics of the customer and PV system. Consequently, the bill-savings value of net metering – and the impact of moving to alternative compensation mechanisms – can vary substantially from one customer to the next. For these reasons, it is important for policymakers and others that seek to support the development of distributed PV to understand both how the bill savings benefits of PV vary under net metering, and how the bill savings under net metering compare to savings associated with other possible compensation mechanisms.[6]

To advance this understanding, the bill savings from PV were analysed for residential customers of California's two largest electric utilities, Pacific Gas and Electric (PG&E) and Southern California Edison (SCE), based on actual hourly load data from 215 customers within the two utilities' service territories.[7] The focus is on these two utilities, both because of ready access to a sample of load data for their residential customers, and because their service territories are the largest markets for residential PV in the country.

The bill savings were first computed based on current net metering rules and retail electricity rates, and then the value of the bill savings under net metering were compared to three potential alterative compensation mechanisms, each of which credits some or all PV production at prices based on the state's Market Price Referent (MPR).[8] In the course of developing these comparisons, a number of critical underlying issues that influence the value of the bill savings

[5] 43 states and Washington DC require some or all utilities to offer net metering, and utilities in 3 additional states offered net metering voluntarily (Database of State Incentives for Renewable Energy (DSIRE), 2010).
[6] It should be noted that the customer economics of PV is just one of many issues and trade-offs that policy makers and state utility regulators consider with respect to rate design, net metering, and policies for supporting solar deployment.
[7] Although the focus of this chapter is solely on residential customers, other studies have shown that the bill savings from net metered PV is lower for commercial customers in California than for residential customers (Mills et al., 2008; E3, 2010a). It follows that the benefits of net metering for PV customers, relative to alternative forms of compensation, are likely higher for residential customers in California than for commercial customers.
[8] The MPR is the price used to evaluate wholesale contracts with renewable generators and is intended to represent long-run avoided generation supply costs, based on the cost of a combined-cycle natural gas fired generator.

under net metering, and thus also the value of net metering relative to alternative compensation mechanisms are also examined, including retail rate design, PV system size, PV orientation, and customer load characteristics.

The work presented in this chapter is based on a LBL report (Darghouth et al., 2010), and then as an article in Energy Policy (Darghouth et al., 2011), and builds on a body of literature that has investigated various aspects of the customer economics of PV under net metering and the relationship of the customer-economics of PV to retail rate structures. Of particular note, Borenstein (2007) calculated the bill savings for net-metered residential customers of PG&E and SCE with 2 kW PV systems, in order to determine whether mandatory TOU rates for PV customers would cause a reduction in bill savings. The present study relies on the same sample of customer load data (see Section 2.2.3) as used in Borenstein (2007), updating the analysis based on the set of residential retail rates offered by PG&E and SCE as of 2009, and extending the analysis by evaluating bill savings under varying PV system sizes and by comparing the value of the bill savings between net metering and several alternative compensation mechanisms. Another publication is the cost-effectiveness evaluation of net metering in California, prepared by Energy and Environmental Economics (E3) for the California Public Utilities Commission (E3, 2010a). The E3 study and the present analysis both address the economics of net metering in California, but have a different scope and focus on a different set of questions. The E3 report is focused principally on evaluating the total costs and benefits of net metering to the utility and its ratepayers. In doing so, it estimates the net cost to the utility and its ratepayers of providing bill credits to net-metered customers for electricity exported to the grid (i.e., for the *portion* of onsite electricity generation that exceeds contemporaneous electricity consumption). In addition, the E3 study includes in their analysis residential and non-residential net-metered customers of all three electric investor-owned utilities (IOUs) in California, as well as all types of net-metered generation.

Other related studies include Hoff and Margolis (2004), Borenstein (2008), and Bright Power Inc. *et al.* (2009), all of which show that net-metered time-of-use and/or real-time pricing rates can increase the value of PV generation to the customer. MRW and Associates (2007), meanwhile, evaluate which retail rate structures provide the greatest benefits to different classes of PV customers in California. Mills *et al.* (2008) investigate the impact of retail rate structure on the value of bill savings for commercial customers in California, focusing in part on the extent to which PV can reduce customer demand charges. VanGeet *et al.* (2008) calculate the rate impacts of demand charges and energy charges on the bills of commercial customers with PV systems in the city of San Diego. Finally, Cook and Cross (1999) estimate the costs and benefits of net metering in Maryland from the perspectives of participating customers, non-participants, and utility shareholders, based on a hypothetical net-metered PV customer.

The boundaries and limitations of the analysis presented in this chapter should be clearly acknowledged. First, the current residential retail rates offered by PG&E and SCE are unique in several respects, and thus the specific findings presented in this chapter cannot be generalized to apply to other utilities or states. Second, the analysis is based on a sample of customers that, while geographically diverse, may not be statistically representative of the entire population of residential customers in either PG&E's or SCE's service territories, and may not be representative of the current population of residential customers with PV systems. Third, the analysis focuses exclusively on the value of the bill savings provided to customers with PV; it does not consider the overall cost-effectiveness of distributed PV for an individual customer, nor does it consider the value or cost-effectiveness of distributed PV from the perspective of the utility, non-participating ratepayers, or society-at-large. Finally, in comparing net metering to several alternative compensation mechanisms, only the value of the bill savings or bill credits provided to customers through each compensation mechanism is considered here; net metering may provide other advantages and disadvantages (both financial and otherwise) relative to the alternative compensation mechanisms considered, but these are not covered in the analysis presented here.[9]

The remainder of this chapter is organized as follows. Section 2.2 describes the data used within the analysis and the basic analytical framework used to calculate customer utility bills and the value of the bill savings from PV under net metering and under each of the alternative compensation mechanisms. Section 2.3 presents intermediate results showing how the least-cost rate, among the set of residential retail rates offered by each utility, varies with PV system size for customers with net metered PV systems. Section 2.4 describes the value of the bill savings from PV under net metering and the associated variability across customers, including several sensitivity analyses to explore how different rate choices and PV panel orientations impact the bill savings. Section 2.4 also presents two side-analyses examining, first, the effect of recent revisions to SCE's residential time-of-use (TOU) rates on the bill savings from net metered PV (2.4.3), and second, the PV system size at which customers exhaust their annual bill savings under current net metering rules (2.4.4). Section 2.5 then examines three alternative compensation mechanisms for distributed PV, and compares the value of the bill savings between each of these alternatives and net metering. Finally, brief conclusions and policy implications are presented in section 2.6.

2.2 Data and Analysis Methods

In this section, the data used within the analysis and the basic analytical framework used to calculate customer utility bills and the value of the bill savings from PV is described. Key data inputs include: residential retail rate definitions and prices, net metering rules, MPR definitions and prices, customer load data, and simulated PV generation data.

2.2.1 Utility Tariff Descriptions

2.2.1.1 Current Residential Electricity Rates

PG&E and SCE both offered residential customers the choice between a non-time-differentiated (i.e., "flat") rate and a time-of-use (TOU) rate.[10] The utilities' flat rates were "inclining block" rates with five usage tiers and increasing volumetric charges for usage within

[9] As one set of examples, alternatives to net metering that entail explicit sales of electricity by the customer to the utility may be subject to income taxes, may give rise to federal regulatory compliance requirements, and could potentially interfere with common customer financing mechanisms like third-party power purchase agreements (PPAs)/leases and property assessed clean energy (PACE) financing.

[10] SCE's tariff book includes three residential TOU rates; however, two of these rates (Schedules TOU-D-1 and TOU-D-2) were closed to new customers on October 1, 2009, and were replaced by the third TOU rate (Schedule TOU-D-T). The analysis focuses primarily on Schedule TOU-D-T, although Section 2.4.3 discusses the implications of this change in TOU rates.

each successive tier. The lowest tier was the baseline allotment, which varies according to the baseline region in which the customer is located and is designed to cover 50-60% of the average electricity consumption in the region.[11] The other four tiers were defined as percentages of the baseline: specifically, Tier 2 is 100-130% of the baseline, Tier 3 is 130-200%, Tier 4 is 200-300%, and Tier 5 is greater than 300%.

Figure 3(a) displays the tiered rate structure for PG&E's and SCE's flat rates, as of March 2010. As shown, prices for usage in the highest tiers of both utilities are considerably greater than in the baseline tier, but PG&E's tiers were significantly steeper than SCE's.[12] Specifically, volumetric charges under PG&E's flat rate rise from $0.12/kWh for usage in Tier 1 up to $0.50/kWh in Tier 5, while SCE's rate rises from $0.13/kWh for usage in Tier 1 up to $0.31/kWh in Tier 5. Both utilities' flat rates also specify a minimum monthly charge, and SCE's flat rate also contains a fixed customer charge.

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

The volumetric prices of both utilities' TOU rates are summarized in Figure 3(b-c), along with the flat rates, for comparison. On PG&E's TOU rate, the combination of steep tiering and a TOU rate structure yields quite high marginal prices for high-usage customers during summer on-peak periods (e.g., $0.61/kWh and $0.68/kWh for Tier 4 and 5, respectively). Prices on SCE's TOU rates do not rise as high, with summer on-peak prices reaching $0.53/kWh. The utilities' TOU rates all contain both fixed and minimum monthly customer charges. Note that the SCE TOU rate described in Figure 3(c) is the recently introduced TOU-D-T rate, which replaces two other residential TOU rates (TOU-D-1 and TOU-D-2) that have no usage tiers.

[11] There are 10 baseline regions in PG&E's service territory and 9 in SCE's, each corresponding to a particular climate zone.

[12] Legislation passed in 2001 (Assembly Bill 1X) froze prices for usage up to 130% of the baseline (Tiers 1 and 2), contributing to the steep tiering structure in place today. More recently, legislation passed in 2009 (Senate Bill 695), allows Tier 1 and 2 rates to be increased by up to 5% per year, which will presumably lead to less steeply tiered rates and thus reduce the variability across customers in the value of the bill savings provided by net-metered PV.

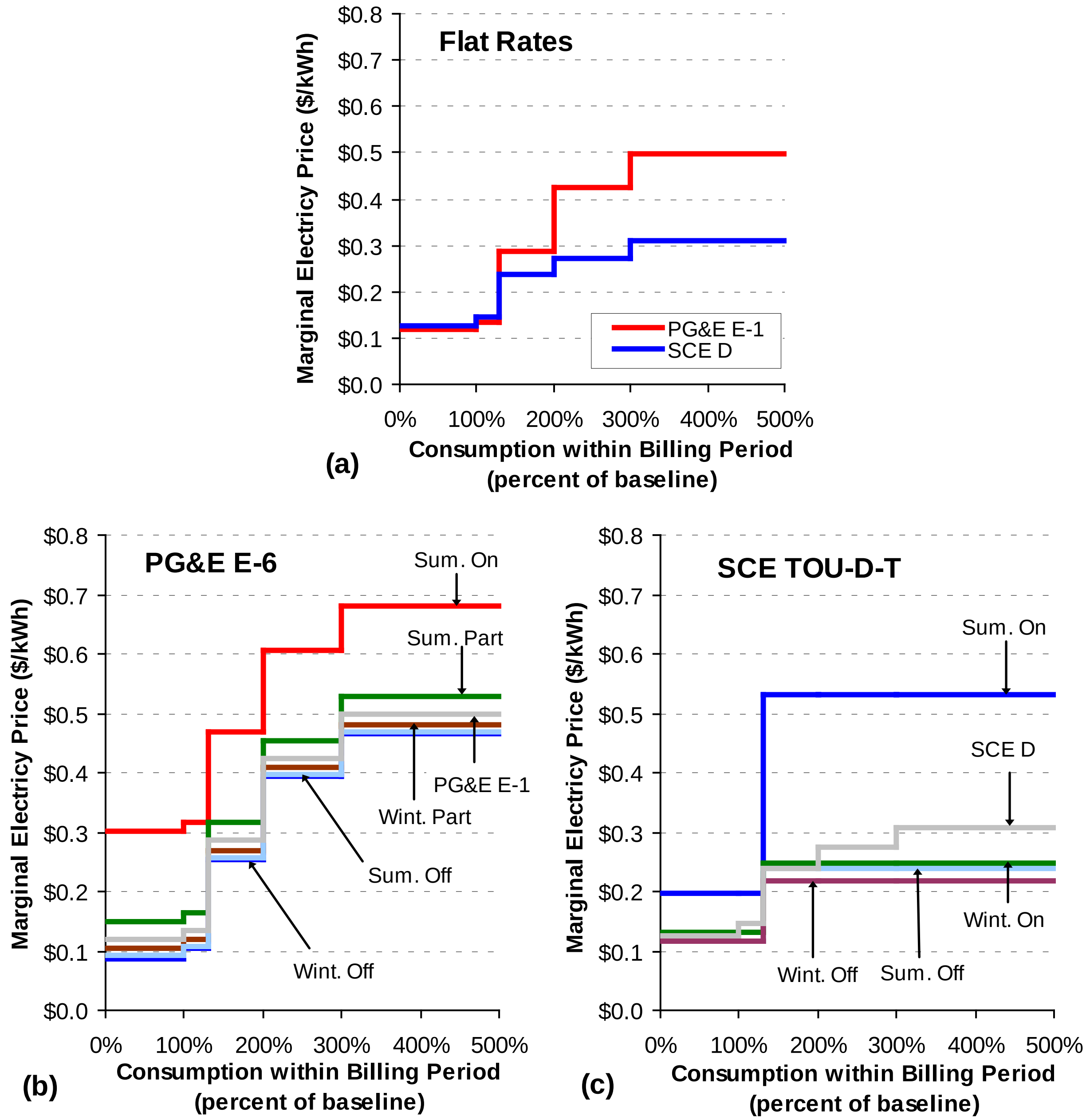

Figure 3. Prices under Current PG&E and SCE Residential Retail Rates

Table 1. TOU Period Definitions

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

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

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

2.2.1.2 Current Net Metering Tariffs

PG&E and SCE both offer net metering to residential customers with PV systems. Under current the terms of the net metering tariffs, customers are able to offset volumetric charges within each billing period, but fixed charges cannot be offset, and minimum monthly charges still apply. Any excess bill credit remaining at the end of each monthly billing period is carried over to the subsequent billing period. However, under existing net metering tariffs, any excess bill credits remaining at year-end are forfeited.[13] For a customer on a flat rate, bill credits within any 12 month period of time are exhausted when annual PV generation is approximately equal to annual consumption.[14] For a customer on a TOU rate, however, bill credits may be exhausted by PV systems that meet less than 100% of the customer's usage, if the PV generation is more highly concentrated during high-priced TOU periods than is the customer's usage.

2.2.2 The Market Price Referent

The alternative compensation mechanisms considered in this chapter are based upon California's Market Price Referent (MPR). The MPR is a price established by the CPUC and

[13] A law passed in California, Assembly Bill (AB) 920, alters this element of the net metering rules by requiring utilities to offer customers the choice either to receive compensation for net surplus electricity at the end of the year or to roll forward the net surplus electricity to be used as a credit against future electricity consumption. As of the writing of this chapter, in 2010, revised tariffs implementing AB 920 had not yet been approved by the California Public Utilities Commission, and therefore the changes required by AB 920 are not reflected in the analysis.

[14] Because net metered customers cannot eliminate minimum monthly charges, a customer on a flat rate could actually exhaust her annual bill credits with a PV system that generates somewhat less than her annual consumption.

updated each year that is intended to represent the long-term market price of electricity, based on the ownership, operating, and fixed-price fuel costs for a new natural gas-fired combined cycle gas turbine (CCGT). The original purpose of the MPR was to serve as a benchmark for assessing the above-market costs of contracts with renewable generators signed by the state's investor-owned utilities for complying with California's RPS. More recently, it has become the basis for the contract price under California's small renewable generator feed-in tariff program. That program, which is available to certain solar and other renewable generation projects smaller than 1.5 MW, provides an alternative to net metering under which customers can opt to either sell all electricity generated by their system under an MPR-based feed-in tariff or use their renewable generator to first meet on-site load and sell only the excess generation to the utility under the feed-in tariff. Two of the alternative compensation mechanisms considered in this chapter are modeled after, though not identical to, the two compensation options under the state's existing feed-in tariff program.

The MPR has several elements. The "baseload" MPR price, which is based on the long-term cost of a CCGT, is updated annually and varies according to the year in which the renewable energy project enters commercial operation and the contract length (see Table 2 for the 2009 MPR baseload prices). To establish the MPR price for a specific renewable energy generator or contract, the baseload MPR price is adjusted according to the Time-of-Delivery (TOD) period within which electricity is generated (see Table 3), by multiplying the baseload MPR rate by the utility-specific TOD adjustment factor. Thus, similar to the utilities' retail TOU rates, the MPR TOD adjustment factors provide higher levels of compensation during summer afternoon hours than at other times, although specific structural details (e.g., the definitions of the time periods and price spread between time periods) differ between the retail TOU rates and the MPR TOD factors.

Table 2. 2009 Baseload MPR Prices ($/kWh)

First Year of Commercial Operation	10-Year	15-Year	20-Year	25-Year
2010	0.08448	0.09066	0.09674	0.10020
2011	0.08843	0.09465	0.10098	0.10442
2012	0.09208	0.09852	0.10507	0.10852
2013	0.09543	0.10223	0.10898	0.11245
2014	0.09872	0.10593	0.11286	0.11636
2015	0.10168	0.10944	0.11647	0.12002
2016	0.10488	0.11313	0.12020	0.12378
2017	0.10834	0.11695	0.12404	0.12766
2018	0.11204	0.12090	0.12800	0.13165
2019	0.11598	0.12499	0.13209	0.13575
2020	0.12018	0.12922	0.13630	0.13994

Source: CPUC (2009)

Table 3. MPR TOU Periods and TOD Adjustment Factors, as of 2009.

Months	TOD Period Name	TOD Period Definition	Adjustment Factor
PG&E			
Summer (June-Sept.)	Super-Peak	M-F 12pm-8pm	2.205
	Shoulder	M-F 6am-12pm, 8pm-10pm; Sat-Sun 6am-10pm	1.122
	Night	Everyday 10pm-6am	0.690
Winter (Oct.-Feb.)	Super-Peak	M-F 12pm-8pm	1.058
	Shoulder	M-F 6am-12pm, 8pm-10pm; Sat-Sun, holidays 6am-10pm	0.935
	Night	Everyday 10pm-6am	0.764
Spring (March-May)	Super-Peak	M-F 12pm-8pm	1.146
	Shoulder	M-F 6am-12pm, 8pm-10pm; Sat-Sun 6am-10pm	0.846
	Night	Everyday 10pm-6am	0.642
SCE			
Summer (June-Sept.)	On-Peak	M-F 12pm-6pm	3.13
	Mid-Peak	M-F 8am-12pm, 6pm-11pm	1.35
	Off-Peak	M-F 11pm-8am; Sat-Sun all day	0.75
Winter (Oct.-May)	Mid-Peak	M-F 8am-9pm	1.00
	Off-Peak	M-F 6am-8am, 9pm-12am; Sat-Sun, holidays 6am-12am	0.83
	Super-Off-Peak	Everyday 12am-6am	0.61

Source: CPUC (2009)

2.2.3 Customer Load Data

The analysis relies on 15-minute interval load data from residential customers located throughout the service territories of PG&E and SCE, none of which have PV systems installed. These data were originally collected as a part of California’s Statewide Pricing Pilot (SPP), which sought to analyze changes in electricity consumption associated with peak pricing rate structures. The analysis specifically utilizes data for the SPP control group of customers, who were not under peak pricing rate structures. The original SPP control group dataset consisted of load data from 442 customers, who were chosen using Bayesian sampling techniques in order to reflect the diversity of California customers across climate zones (Charles River Associates, 2005). Following the data cleaning process described below, load data from 215 of these customers (118 PG&E customers and 97 SCE customers) were ultimately used in the analysis.

Several steps were required to prepare the SPP load data for analysis. First, a common 12-month time period was selected. The original data spanned 15 months, from May 19, 2003 to September 30, 2004. For the analysis, data from the last 12 months of this time period (i.e., October 1, 2003 to September 30, 2004) was used, as this was the period with the least amount of missing load data. Second, two types of customers were removed from the dataset: multi-family housing (N=133) and single-family customers with more than seven cumulative days of missing or zero-value load data (N=145). Third, gaps in the load data for the remaining customers were filed. For gaps of four continuous hours or less, the missing data were replaced with linearly interpolated values from the hours immediately preceding and following the gap. For gaps longer than four continuous hours, the entire day was replaced with data from the previous weekday/weekend (depending on whether the missing data occurred on a weekday or weekend).

After cleaning the raw data set, the resulting working dataset contained 227 customers. Each customer was then assigned to a utility and baseline region, using Geographic Information System (GIS) software and the zip code data records contained within the SPP database. Based on this GIS analysis, 118 customers were determined to be located in PG&E's service territory, 97 customers in SCE's, and 12 in San Diego Gas and Electric (SDG&E)'s territory. Customers of SDG&E were excluded from the analysis, due to the inadequate sample size.

Figure 4 shows the distribution in usage – expressed here as the average monthly usage per customer – across the customers in the final data set. PG&E customers in the sample consumed 667 kWh/month in the median case and 734 kWh/month on average, while the SCE customers consumed 730 kWh/month in the median case and 827 kWh/month on average. The figure compares the average usage per customer between the sample and the total population of residential customers of each utility. As shown, customers in the final sample have, on average, higher electricity consumption than the overall population of residential customers (by 30% and 38% for PG&E and SCE, respectively). This is, in part, a consequence of the fact that customers in multi-family residential buildings (e.g., apartments), who on average have lower electricity consumption than customers in single-family homes, were removed from the sample.[15]

[15] Had the multi-family customers been included, the mean consumption for the sample would have been 625 kWh/month and 746 kWh/month, for PG&E and SCE customers, respectively, or 11% and 26% over the 2007 average consumption for PG&E and SCE customers, respectively.

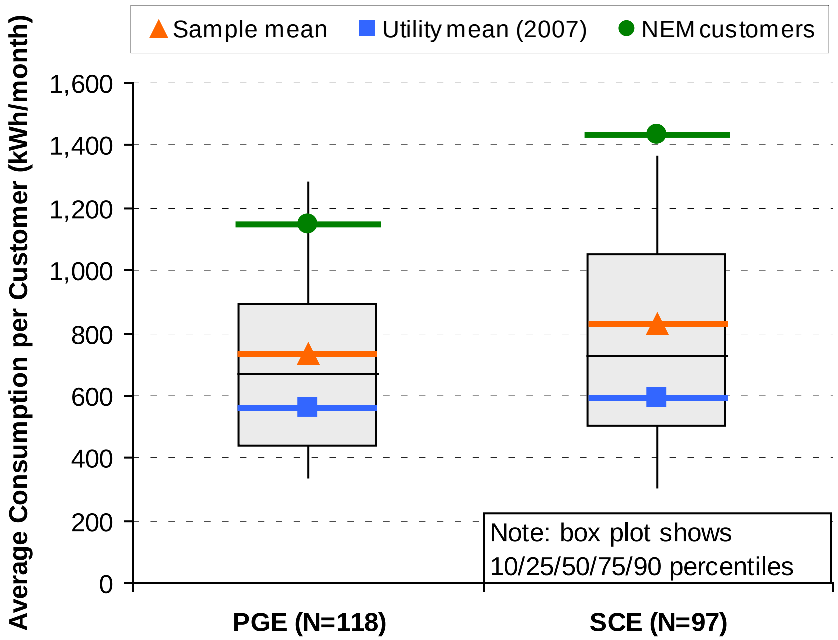

Figure 4. Distribution in Average Monthly Consumption across Customers in Data Sample[16]

However, the customers in the sample appear to have average electricity consumption well below the current population of residential customers with PV. For example, MRW & Associates (2007) presents analysis based on a sample of approximately 5,600 PG&E customers with net metered PV systems, and those residential customers were found to have an average consumption of 935 kWh/month prior to PV installation. The recent CPUC net metering cost-effectiveness evaluation (E3, 2010a), meanwhile, estimates the gross consumption level for a large fraction of the net-metered customers in the state. Among the approximately 23,000 PG&E net-metered residential customers in that study's sample, the average consumption is 1,148 kWh/month, and for the approximately 7,700 SCE net-metered residential customers, the average consumption is 1,434 kWh/month (DeBenedictis, 2010). These latter data, in particular, imply that average consumption by residential customers with PV systems in California is roughly double the average consumption by all residential customers in the state, and is considerably higher than the customer sample used in the present analysis.

Figure 5 shows the distribution of customer-months within the sample terminating in each usage tier (i.e., the highest usage tier reached in each customer-month). Among the PG&E customers in the sample, approximately one-third of all customer-months do not exceed Tiers 1 or 2, with most the remaining customer-months reaching Tiers 3 and 4, and 13% reaching Tier 5. The distribution for SCE customers in the sample is skewed slightly more towards high-usage tiers, with only 21% of customer-months terminating in Tiers 1 or 2, and almost one-quarter reaching Tier 5.

[16] Data on average usage by residential customers of each utility is derived from Energy Information Administration, Form EIA-861. Data on average usage by actual PG&E and SCE residential Net Energy Metering (NEM) customers is from the E3 NEM cost-benefit analysis, as reported by DeBenedictis (2010).

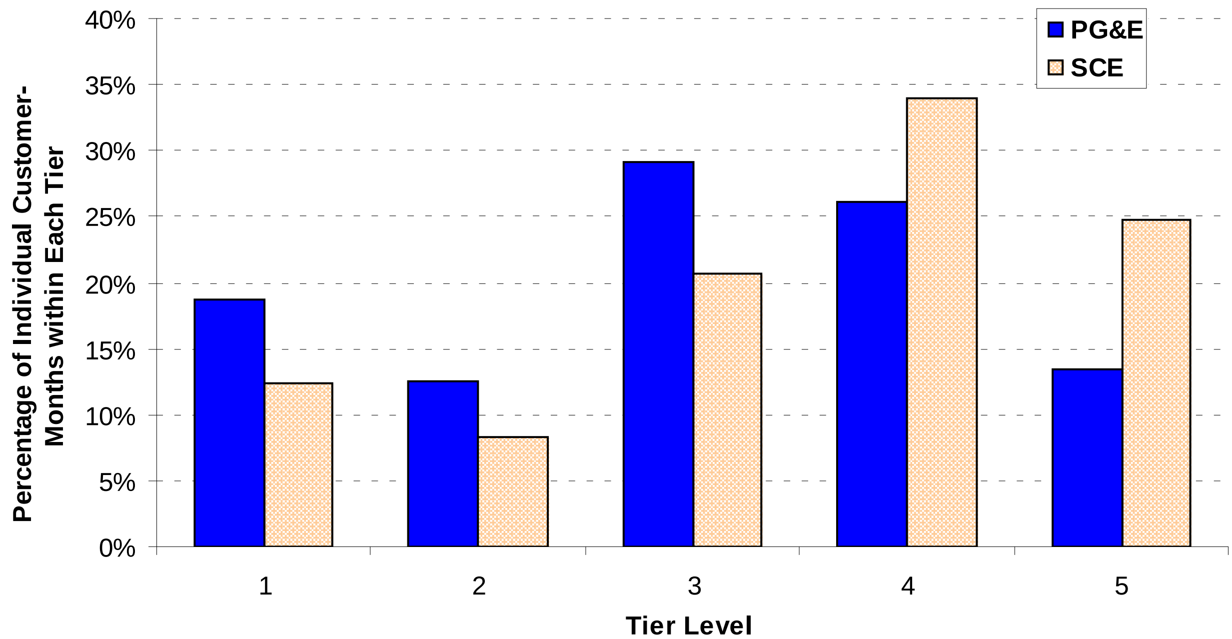

Figure 5. Customer Sample Distribution by Usage Tier

Figure 6 shows the distribution, across customers in the sample, of the percentage of each customer's annual usage occurring within each TOU period. Of greatest importance, in terms of understanding the relative cost of the flat rate vs. the TOU rate options, is the percentage of customers' consumption occurring during the high-priced summer peak period. In the median case, 9.4% of PG&E customers' annual usage and 9.8% of SCE customers' annual usage occurs during each utility's respective summer on-peak period. However, as indicated by the height of the bars surrounding the median values, many customers' load profiles are either more or less concentrated during the summer on-peak period.

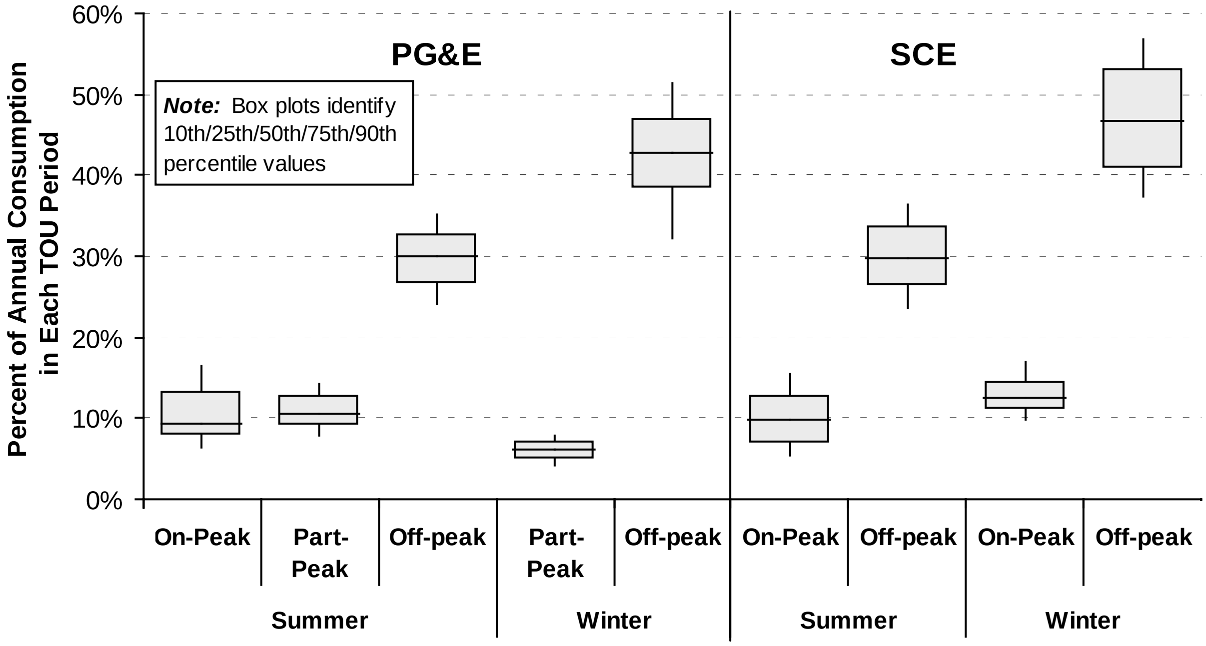

Figure 6. Customer Load Distribution by TOU Period

2.2.4 Simulated PV Generation Data

Each customer within the load data sample was matched with simulated PV production data. For the analysis, PV simulation data from the National Renewable Energy Laboratory (NREL) was used, based on the PVFORM/PVWatts Model and the National Solar Radiation Database (NREL, 2007, 2010; Denholm et al., 2009). The data consists of simulated hourly AC electricity generation for a 1 kW system located at each of 73 weather stations located throughout California, derived from weather data for the same 12-month period as the customer load data (October 1, 2003 through September 30, 2004). Each customer within the load data set was assigned to the PV production data from the nearest of the 73 weather stations.[17]

Simulated PV production data were obtained for a number of PV panel orientations. For the base case analysis, simulated production for a south-facing (i.e., 180º azimuth) system with a 25º tilt is used, as this is the azimuth that usually produces the most kWh per kW in the northern hemisphere, and 25º is a typical angle for a sloping rooftop. Sensitivity analyses for two alternate PV panel orientations were also conducted: a 240º azimuth (approximately west-southwest, though this orientation is referred from here on simply as "southwest") with a 25º tilt, and flat-mounted system (i.e., tilt=0º). The southwest orientation was chosen because systems facing in that direction receive more sunlight during the summer on-peak TOU period when retail electricity rates are highest under the utilities' TOU rates. The no-tilt orientation was chosen to represent systems installed on flat roofs, which are common in some parts of California. Both alternative PV orientations yield less annual PV generation than the base case orientation: based on the location of the customers in the sample, the southwest orientation results in 11% less PV

[17] The weather station nearest to each customer was identified using GIS software. Because customer location data consisted only of the zip code within which each customer was located, the proximity of each weather station to each customer was based on the distance between the weather station and the centroid of the customer's zip code.

electricity production in the median case, and the flat PV orientation results in 10% less electricity production.

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

Figure 7 shows the percentage of annual PV electricity production within each retail-rate TOU period of the two utilities, for each of the three PV orientations included the analysis. Each bar in the figures represents the median value[18], across the customers within the data sample; also included in the figures, for comparison, is the median percentage of customer load within each TOU period (as presented previously in Figure 6). Focusing first on the south-facing systems with a 25º tilt (the base-case PV orientation), 23% and 24% of annual PV electricity production is generated during the high-priced summer peak periods of PG&E and SCE, respectively. PV electricity production is therefore significantly more-concentrated during the summer peak period than is customer usage, with 9.4% of PG&E customer usage and 9.8% of SCE customer usage occurring within each utility's respective summer peak period.

When comparing between the base-case and alternate PV orientations, relatively modest changes in the distribution of PV production across TOU periods were noted. Of most importance, perhaps, is that for both alternate orientations, electricity production is more highly concentrated during summer peak periods, compared to the base-case orientation. This effect is, as expected, more pronounced for the southwest-facing orientation, where 29% and 31% of electricity production occurs during the summer peak period for PG&E and SCE, respectively (compared to 23% and 28% in the base case). Also of note is that flat-mounted systems yield more highly concentrated electricity production during all summer TOU periods than the base-case orientation. This occurs because the angle of the sun is steeper during the summer, and thus the sunlight hits flat-mounted PV panels at a less oblique angle.

[18] Only the median value is presented (rather than a box-and-whiskers chart, as used in other figures), as the distribution of PV production within each TOU period, across customers, is quite narrow.

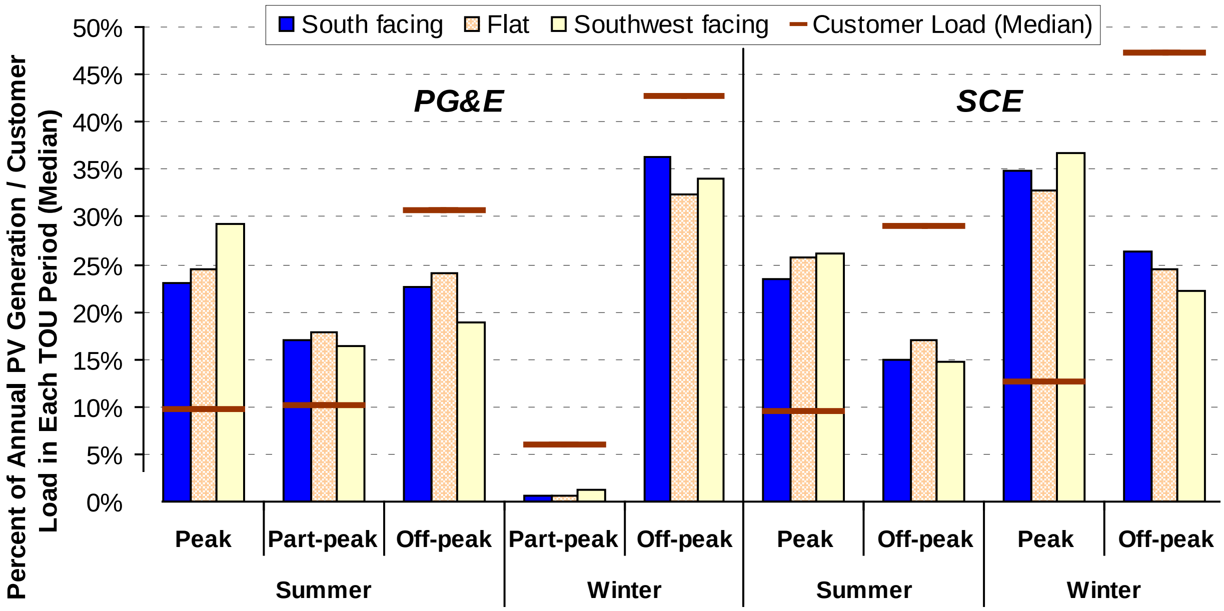

Figure 7. Distribution of PV Electricity Generation by Retail TOU Period

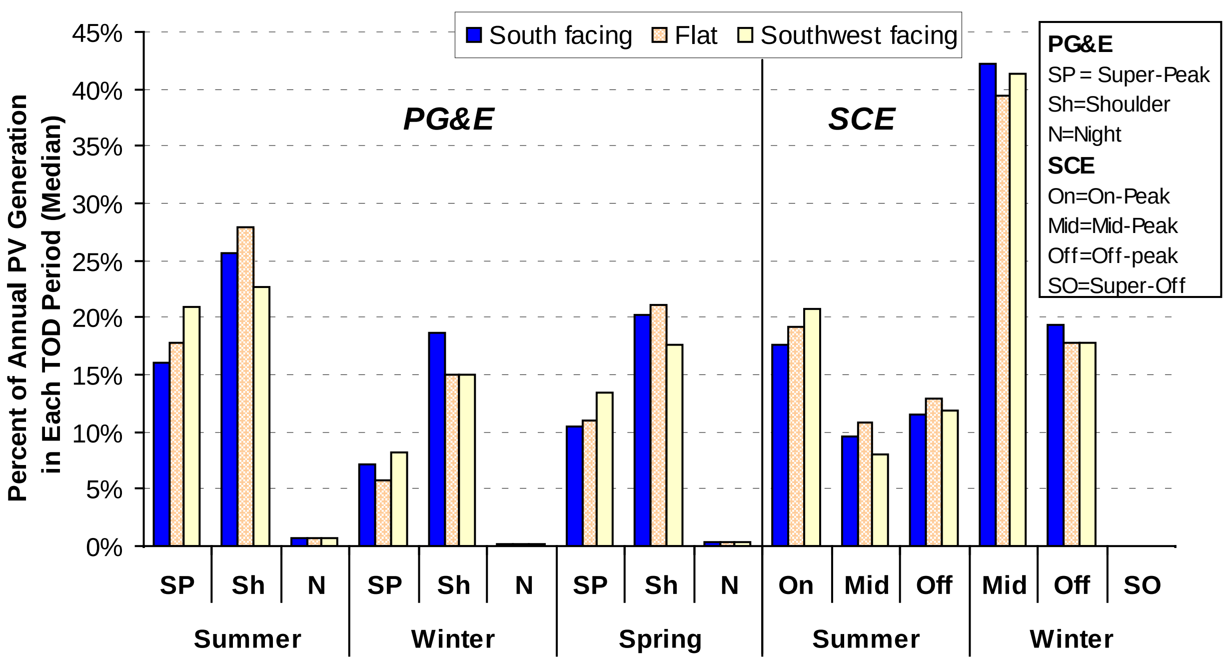

Figure 8. Distribution of PV Electricity Generation by MPR-TOD Period

As described further in Section 2.2.6, the analysis also considers scenarios in which PV generation is compensated, in whole or in part, based on the utilities' MPR pricing structures, which have different TOD period definitions than the utilities' retail TOU rates. Figure 8 presents the distribution of PV production across the MPR-TOD periods for each PV orientation. As in the previous figure, each bar represents the median value across the customers within the data sample. Focusing first on the south-facing systems, 16% of annual PV generation occurs within PG&E's highest priced MPR-TOD period (Summer Super-Peak), and 17% occurs within SCE's highest priced period (Summer On-Peak). These percentages are smaller than the corresponding values for the summer peak periods under the utilities' retail TOU rates, because the highest priced MPR-TOD periods are defined to cover a narrower set of hours each day and/or a narrower set of months, as discussed previously. Similar to what was observed with the retail TOU rates, compared to the base-case PV orientation, the alternate PV orientations yield a greater percentage of total production during the highest-priced MPR-TOD periods. For the southwest-facing systems, 21% of annual production occurs within PG&E's Summer Super-Peak MPR-TOD period as well as within SCE's Summer On-Peak period.

2.2.5 Utility Bill Calculations

Annual utility bills for each customer were calculated, both with and without a PV system, under each of the currently available residential retail rates offered by the utility in whose service territory the customer is located. Utility bills with PV systems were calculated for each possible combination of:

- PV-to-load ratio (25%, 50%, and 75%);
- PV orientation (south-facing at a 25° tilt, southwest facing at a 25° tilt, and flat); and
- PV compensation mechanism (net metering, MPR-based feed-in tariff, hourly netting, and monthly netting).

All bill calculations are based on the retail rates, net metering rules (if applicable), and MPR prices (if applicable) in place as of March 2010. Further details on the bill calculation procedure for each PV compensation mechanism are as follows.

2.2.5.1 Net Metering

For customers on the flat rate (that is, the non-TOU rate), monthly utility bills were calculated by first computing the customer's net electricity consumption – that is, the difference between gross electricity consumption and PV electricity production – for the month. Net consumption was then compared to the customer's baseline allocation for that month to determine the quantity of net consumption within each usage tier. Finally, the applicable price for each tier was applied to the net consumption quantity within each tier.

For customers on a TOU rate, monthly utility bills are calculated according to the same basic series of steps, except that charges and credits are computed for each TOU period. First, the net electricity consumption within each TOU period of the month was calculated. Total net consumption for the billing month (i.e., the sum of the net consumption over all TOU periods) was then compared to the customer's baseline allocation for that month to determine the quantity of consumption within each usage tier. Charges for net consumption within each usage tier were then calculated based on a weighted-average of the volumetric prices for each TOU period, where those prices were weighted according to the customer's net consumption within each TOU period. This computation is described by equation (1):

$$Bill = \sum_{i=1}^{5} \frac{c_i}{c_t}\left(r_{p,i} \cdot c_p + r_{pp,i} \cdot c_{pp} + r_{op,i} \cdot c_{op}\right) \tag{1}$$

where c_i is the net consumption in tier i, c_t is net consumption for the entire billing month, $r_{p,i}$ is the peak rate for tier i, c_p is the net consumption during peak periods, $r_{pp,i}$ is the part-peak rate for tier *i* (if applicable), c_{pp} is the net consumption during part-peak periods (if applicable), $r_{op,i}$ is the off-peak rate for tier i, c_{op} is the net consumption during off-peak periods. [19]

For all customers (both those on TOU rates and those on the default non-TOU rate), if the monthly charges calculated according to the preceding procedures are less than the minimum monthly charge under the given retail tariff, the difference is carried forward to the following billing month as a bill credit. However, at the end of the 12-month analysis period, any remaining bill credits are forfeited by the customer.[20]

2.2.6 Alternative PV Compensation Mechanisms

Three hypothetical alternatives to net metering were considered under which some or all PV production is compensated at an MPR-based rate (rather than at the retail electricity rate, as under net metering) and is credited against charges for the customer's usage. These three alternatives are:

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

The first two of these alternative compensation mechanisms are modeled after – though not identical to – California's existing feed-in tariffs for small renewable generators, which provide customers with certain solar and other renewable generation projects the option to either sell all electricity generated by their system at MPR-based prices or use their renewable generator to

[19] Although the procedure embodied in equation (1) is defined for a rate structure with three TOU periods per month and five usage tiers (the most complex of the rate structures evaluated), it was used for all of the residential retail rates analyzed, by using constant prices across TOU periods for non-TOU rates and for TOU rates with only two TOU periods in a particular billing month, and by using constant prices across usage tiers for SCE's TOU-D-T rate, which has only two tiers.

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

first meet on-site load and sell only the excess generation to the utility at MPR-based prices.[21] The third option is a variant of net metering that exists in a number of states, under which customers receive payment for monthly excess generation at an avoided cost based rate, rather than rolling the net excess generation forward to the following month and thereby receiving compensation at retail electricity prices.

The bill calculation procedure for each of the three alternative compensation mechanisms is described below. In each case, the approved 2009 baseload MPR rate for a 20-year contract with deliveries beginning in 2010 was used, equal to $0.09674, plus an time-of-delivery adjustment factor.

Option 1: MPR-Based feed-in tariff. Under this option, all electricity generated by the PV system is compensated at the prevailing MPR-TOD rate (see Table 4). Compensation for PV generation and charges for consumption are therefore entirely independent of one another, and the consumption portion of the bill is the same as in the “no PV” case (i.e. the PV system is not installed “behind the meter”). Bill credits for PV electricity production in each MPR-TOD period are equal to the product of the quantity of PV generation in the TOD period, the MPR rate, and the applicable TOD factor. Bill credits for each TOD period are then summed to determine the total monthly bill credit for PV electricity production, which is then deducted from the charges for the customer’s consumption to determine the net monthly bill.

Option 2: Hourly netting. This option represents a hybrid between standard net metering and a full feed-in tariff, whereby all PV production up to the customer’s usage level within each hour offsets consumption, but excess PV production within each hour is compensated at the prevailing MPR-TOD rate. To compute monthly utility bills under this compensation mechanism, net consumption (subject to a minimum value of zero) and excess PV production are computed for each hour. Hourly net consumption values are summed for each TOU period, and monthly charges for net consumption are then calculated in the same manner as under standard net metering. The monthly bill credit for PV electricity production is calculated in a similar manner as under Option 1, except that it is based on the sum of excess production within each hour of each MPR-TOD period (rather than on the sum of all PV production within each MPR-TOD period).

Option 3: Monthly netting. This option is similar to Option 2, except that PV generation can offset up to 100% of the customer’s usage within each month (rather than only within each hour), and excess PV production at the end of the month is compensated at an MPR-based rate. In effect, the only difference between this option and standard net metering is that excess production at the end of each month is credited at an MPR-based rate, rather than at the retail rate. The application of the monthly netting option differs slightly depending on whether customers are taking service under a flat rate or TOU rate. For customers on a flat rate, PV production is netted against total monthly consumption, and any net excess PV production at the end of the month is compensated at a single MPR-based price. In that case,

[21] Under the “excess sales” option of the existing feed-in tariffs, excess generation may be computed on a sub-hourly basis. Within the analysis, however, excess generation is computed on an hourly basis, as that is the time resolution of the source of simulated solar generation data.

the MPR-based price is an average of the applicable MPR-TOD prices, weighted according to the median percentage of PV production in each MPR-TOD period (see Table 4).[22] For customers on a TOU rate, PV production is netted against monthly consumption *within each TOU period*, and any net excess PV production within each TOU period at the end of the month is compensated at an MPR-based price defined for that particular TOU period. In this case, the MPR-based price for each retail rate TOU period is an average of the MPR-TOD prices overlapping the TOU period, weighted according to the median percentage of PV production occurring within each overlapping MPR-TOD period (see Table 4).[23]

Table 4. MPR-Based Prices for Monthly Excess PV Generation under the Monthly Netting Option

Season*	TOU Period	PG&E	SCE
Customers on Flat Rates			
Summer	n/a	$0.1310	$0.1907
Winter	n/a	$0.0919	$0.0841
Customers on TOU Rates			
Summer	Peak	$0.1819	$0.2571
	Part-peak	$0.1011	n/a
	Off-peak	$0.0991	$0.0856
Winter	Peak	n/a	$0.0500
	Part-peak	$0.1108	n/a
	Off-peak	$0.0915	$0.0468

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

The bill calculation procedures described above are used to calculate the *pre-tax* value of the bill savings under each alternative compensation mechanism. However, explicit payments or bill credits provided to customers for generation exported to the grid (i.e., for generation not used to directly offset consumption) may be subject to federal and state income taxes. In that case, customers may then also be able depreciate the capital costs of their PV system, thereby offsetting, at least in part, taxes assessed on electricity sales. Given that these tax effects are

[22] That is, for each retail rate season, the median percentage, across all customers, of PV generation within each overlapping MPR-TOD period is calculated. Those percentages are then applied to the corresponding MPR-TOD prices to determine a weighted-average seasonal MPR-based price that reflects the median distribution of PV generation within the season. These prices are then applied to monthly net excess generation within the season for all customers taking service on a flat rate under the monthly netting option.

[23] The MPR-based prices for customers on TOU rates under the monthly netting option are calculated and applied in an analogous manner as for customers on flat rates, the only difference being that the prices are based on the median distribution of PV generation occurring within each retail rate TOU period (rather than within the season).

somewhat uncertain, the primary focus is on the *pre-tax* value of the bill savings. However, as a "worst-case" scenario, the *after-tax* bill savings is also assumed under the assumption that customers are taxed for all electricity sales but do not depreciate the capital cost of their PV system. In this scenario, electricity sales are assumed to be taxed at a federal personal income tax rate of 28% (the marginal rate for a married couple filing jointly with taxable income of $137,300 - $209,250 in 2010) and a California personal income tax of 9.55% (the rate for married couples filing jointly with income greater than $92,698).

2.2.7 Value of Bill Savings Metric

To determine the value of the utility bill savings to each customer, the annual utility bill is compared with and without a PV system, for each combination of PV-to-load ratio, PV orientation, and compensation mechanism. Unless otherwise noted, customers are assumed to choose the least-cost rate before and after PV installation. The bill savings are expressed on a $/kWh basis, in terms of the annual reduction in the utility bill per kWh generated by the PV system, as shown in equation (2):

$$Value\ of\ Bill\ Savings = \frac{Bill_{no\ PV} - Bill_{PV}}{PV\ Generation} \tag{2}$$

Expressing the value of bill savings in terms of $/kWh allows for a direct comparison of electricity bills between customers with different loads as well as between alternate PV-to-load ratios. Also, since electricity is charged to retail customers per kWh and the rate paid to generators (e.g. MPR rate) is also per unit energy output, the units and the significance of the numbers can easily be interpreted.

2.3 Least-Cost Rate Selection with Net Metering

For customers that can choose between multiple rate options – in the case of PG&E and SCE residential customers, between a flat rate and a TOU rate – the choice of retail rate can potentially impact the value of bill savings from PV. Throughout most of the analysis, customers are assumed to select the least-cost rate, both before and after PV installation. In this chapter, the cost of electricity between each utility's flat and TOU rate options are compared first, followed by how the least-cost rate choice varies across customers, PV-to-load ratios, and alternate PV panel orientations. How the least-cost rate option depends on customers' load characteristics is then examined in more detail – specifically, the amount of net consumption and the peakiness of the hourly consumption profile. The results presented in this chapter assume that PV production is compensated via net metering; in Chapter 5, an abbreviated analysis of least-cost rate selection under the three alternative PV compensation mechanisms is presented.

2.3.1 Least-Cost Rate Choice across PV-to-Load Ratios

The cost of electricity (COE) is defined as a customer's total annual bill divided by its net annual consumption, which effectively represents the average price paid by the customer for each kWh of net consumption. Figure 9 shows the distribution, across customers in the sample, of the *difference* between the COE on the TOU rate and on the flat rate. Thus, a positive value on the graph indicates that the flat rate is least-cost, and a negative value indicates that the TOU rate is least-cost.

Across the PG&E customers in the sample, the flat rate is consistently least-cost when no PV system is installed, with a median COE $0.014/kWh less than the TOU rate. As the PV-to-load ratio increases, however, the TOU rate becomes progressively more attractive, relative to the flat rate. The logic underlying this trend is simply that, at a low PV-to-load ratio, most customers in the sample would have too much usage during high-priced TOU periods for the TOU rate to be least-cost. However, as the PV system increases in size, it disproportionately reduces the customer's net consumption during high-priced TOU periods, driving down the annual bill on the TOU rate faster than on the flat rate. At a PV-to-load ratio of 75%, the COE on the TOU rate is, on average, substantially less than on the flat rate, with half of the customers in the sample paying at least $0.025/kWh less on the TOU rate, and one-quarter of the customers paying at least $0.061/kWh less. Note, however, that the apparently large difference between the COE on the TOU and the flat rate at a 75% PV-to-load ratio is partly the result of the fact that net consumption (i.e., the denominator in the COE calculation) is relatively small – thus, a relatively large difference in COE between the two rates does not necessarily imply a large difference in the absolute dollar size of the annual utility bill.

The trend for the SCE customers in the sample bears some qualitative similarities to the trend for PG&E customers – namely, the TOU rate becomes progressively more attractive at a higher PV-to-load ratio. This can be attributed to the similar increasing block pricing flat rate structure for both SCE and PG&E. However, at any given PV-to-load ratio, SCE's TOU rate is relatively more attractive compared to its flat rate, than it is for PG&E. With no PV system, the median difference in COE between the TOU rate and flat rate is approximately zero, and at a 75% PV-to-load ratio, the median COE for the TOU rate is $0.044/kWh less than the flat rate (compared to $0.024/kWh less for the PG&E customers). The fact that SCE's TOU rate is relatively more attractive than PG&E's can be loosely attributed to the fact that SCE's TOU rate has only one TOU period (the summer peak period) with prices higher than the flat rate, while PG&E's TOU rate has two TOU periods (the summer peak and summer part-peak periods) with prices higher than the flat rate.

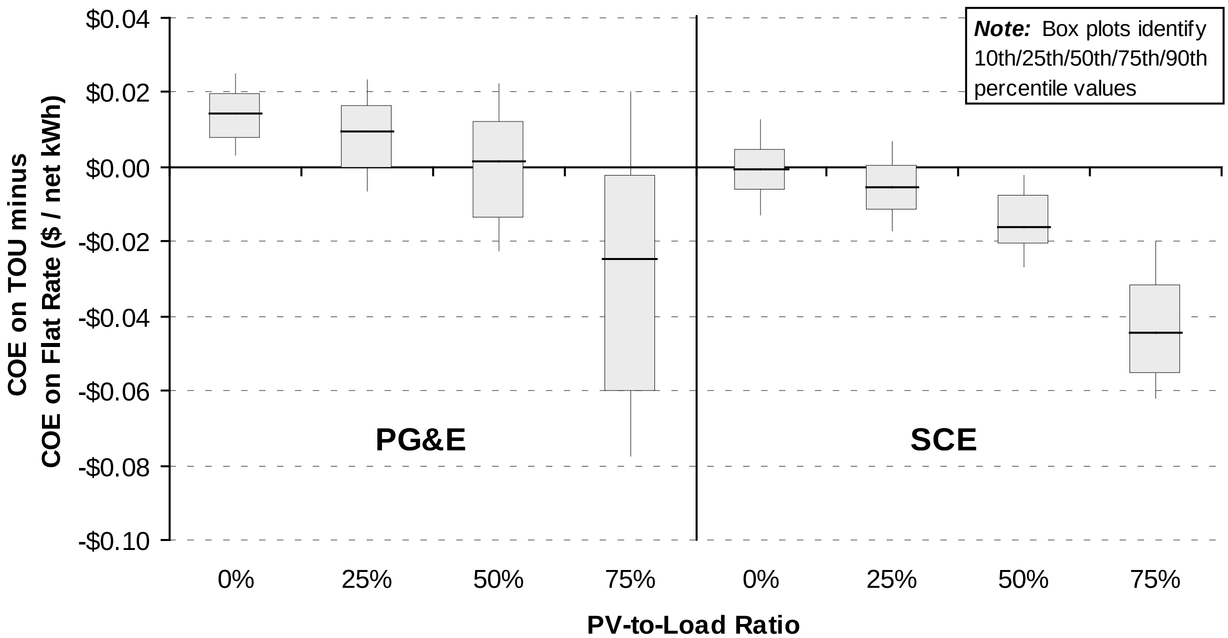

Figure 9. Difference between COE on TOU and Flat Rate

Given the relative COE of the available rate options, Figure 10 shows the corresponding percentage of customers in the sample for which the TOU rate would be the least-cost option. Focusing first on PG&E customers, one sees that with no PV system, the TOU rate is least-cost for almost none of the customers in the sample. As the PV-to-load ratio increases, the TOU rate steadily becomes more attractive (for reasons described previously), becoming least-cost for 78% of customers at a PV-to-load ratio of 75%. Among the SCE customers in the sample, 54% would find the TOU rate least-cost with no PV system installed, and at a PV-to-load ratio of 75%, virtually all of the customers would find the TOU rate least-cost.

The previous analyses assumed the base-case PV panel orientation (south-facing at 25° tilt). Figure 11, however, shows the least-cost rate both for the base-case orientation as well as the two alternate PV orientations considered (southwest-facing at 25° tilt and flat). For PG&E customers, one sees that, with the alternate PV orientations, a somewhat larger percentage of customers would find the TOU rate to be least-cost, compared to the base-case orientation. This is as one would expect, given that the alternate PV orientations result in a higher percentage of PV production occurring during the TOU peak period (as shown previously in Figure 7), which will tend to make the net consumption profile less peaky and the TOU rate more attractive. A similar, though much less pronounced trend, is evident for SCE customers.

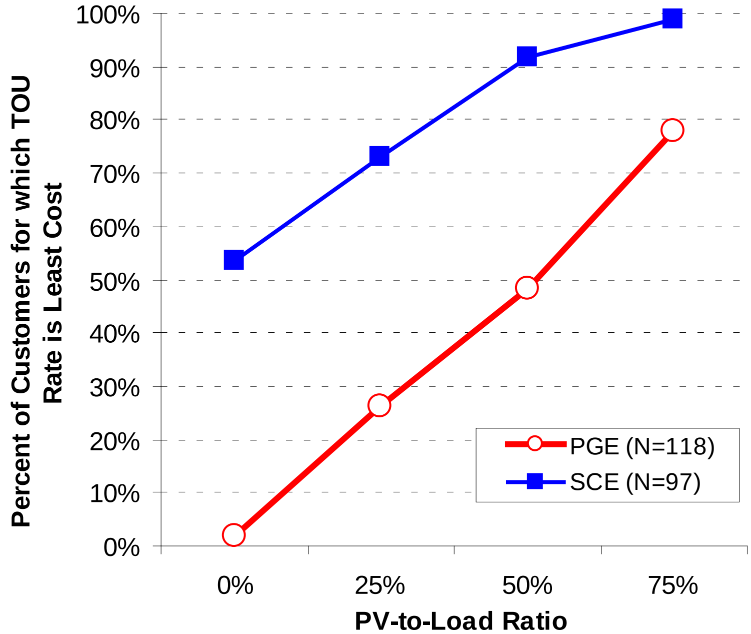

Figure 10. Least-Cost Rate Choice at Varying PV-to-load Ratios

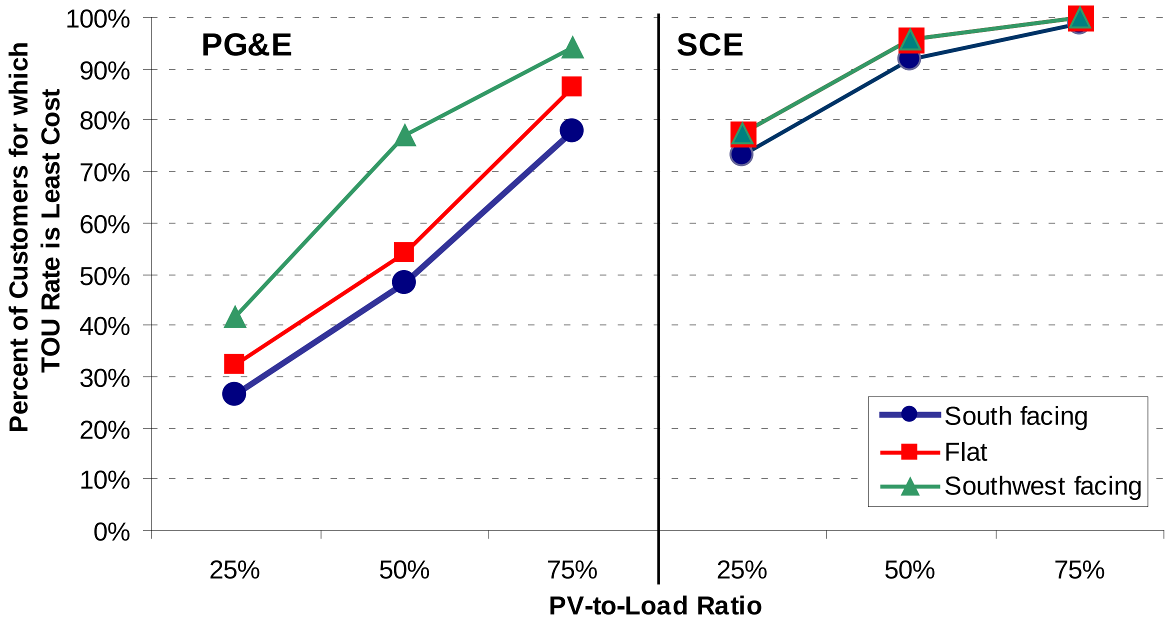

Figure 11. Least-Cost Rate Choice under Alternate PV Orientations

2.3.2 Impact of Customer Size and Usage Profile on Least-Cost Rate Option

For any given set of rate options and PV-to-load ratio, the least-cost rate option will be determined by the characteristics of the customer's consumption pattern. This relationship is illustrated in Figure 12 and Figure 13, which show, for each individual customer, its net annual consumption (on the x-axis, as a percent of baseline), the peakiness of its net load shape (on the y-axis, expressed in terms of net summer peak period consumption as a percent of net annual consumption), and its least-cost rate choice.

For both utilities, the peakiness of the customer's net load shape is the primary determinant of whether the flat rate or TOU rate is least-cost, where customers with relatively peaky load shapes tend to prefer the flat rate. However, net annual consumption is also important, as indicated by the fact that lower-usage customers tend to find the flat rate least-cost. In the case of PG&E, this is due to the fact that its TOU rate (but not its flat rate) contains a fixed daily charge, which adds about $8 to the monthly bill. For low-usage customers with a relatively flat net load shape, this fixed charge is large enough to offset the cost advantage that the TOU rate would otherwise provide. For SCE, net annual consumption has a more modest impact on the least-cost rate choice. Nonetheless, there is a tendency for SCE's higher-usage customers to prefer the TOU rate because SCE's TOU rate has fewer usage tiers than its flat rate.

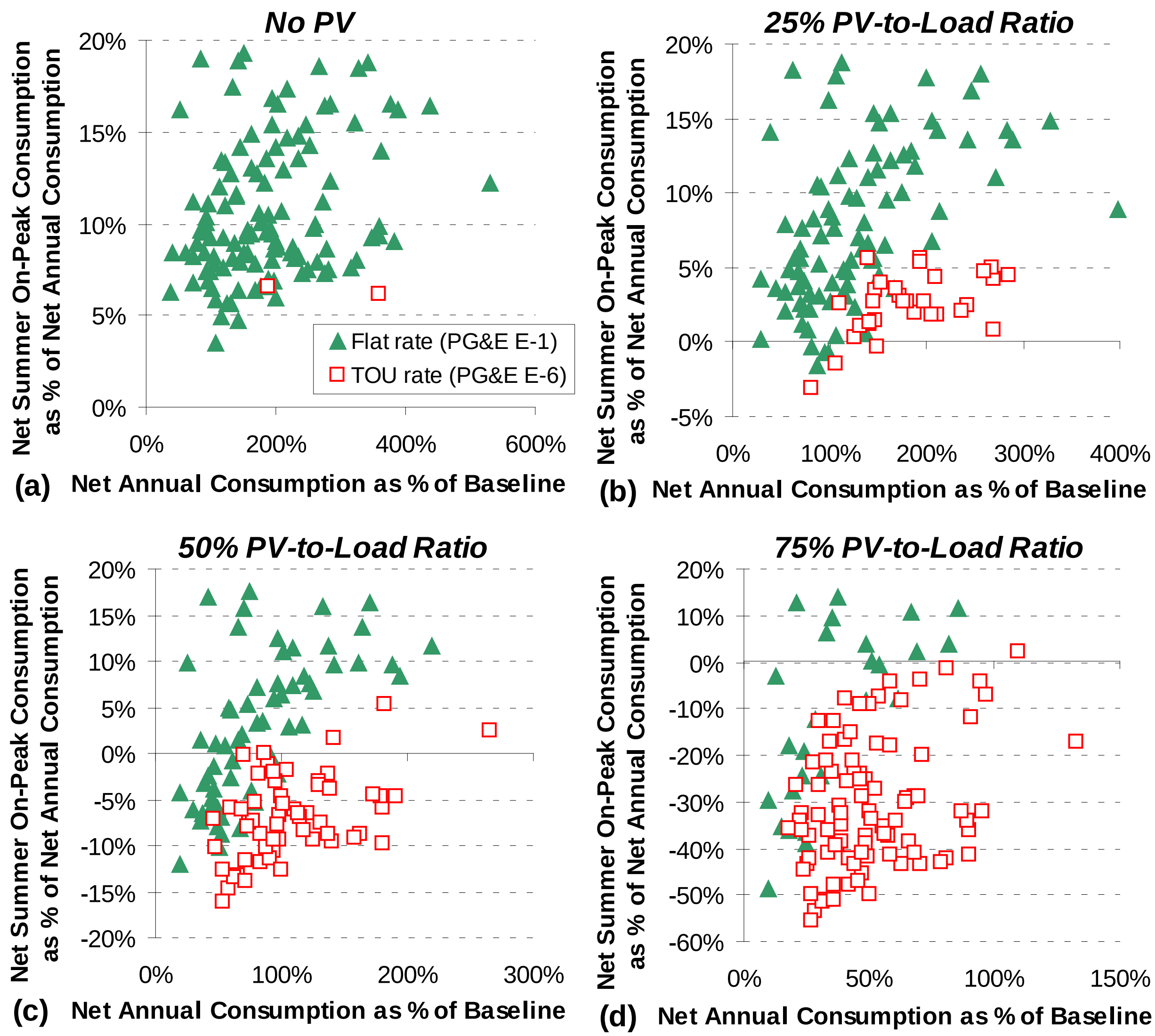

Figure 12. Customer Characteristics Associated with Least-Cost Rate Choice (PG&E)

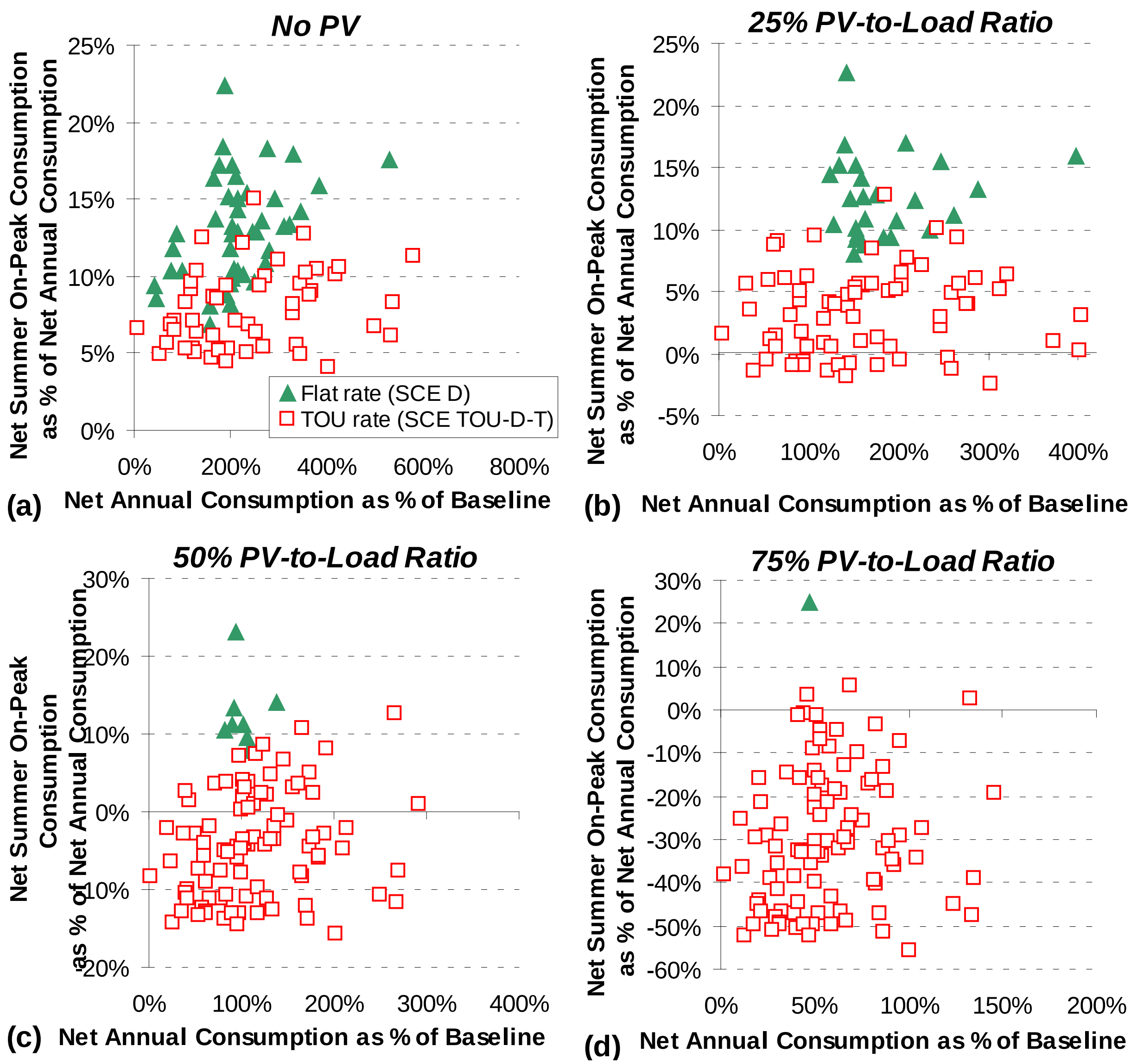

Figure 13. Customer Characteristics Associated with Least-Cost Rate Choice (SCE)

2.4 Bill Savings under Current Retail Rates and Net Metering Rules

This chapter presents the results of the analysis of the value of the bill savings from PV for the PG&E and SCE residential customers in the sample, based on current retail rates and current net metering rules. First, results for the base-case assumptions at varying PV-to-load ratios are presented, highlighting the significance of customer usage level on the value of the bill savings. Two sensitivity analyses are then presented, showing how sub-optimal rate selection and alternate PV panel orientations affect the value of the bill savings. Last, two peripheral, but related, analyses are presented. The first of these briefly investigates the impact of recent change to SCE's TOU rates on the bill savings realized through net metering. The second explores certain implications of a specific provision within existing net metering tariffs – forfeiture by the customer of any excess bill credits at year-end – by identifying the PV-to-load ratio at which each customer would exhaust its annual bill credits.

2.4.1 Bill Savings under Base-Case Assumptions

Figure 14 presents the distribution in the value of bill savings across customers in the sample, under the base-case assumptions (least-cost rate choice both before and after PV installation, and south-facing PV panels at a 25° tilt). Bill savings are expressed in terms of the calculated reduction in the annual utility bill per kWh of PV electricity generated. Across the PV-to-load ratios shown, the median bill savings ranges from $0.19-$0.25/kWh for the PG&E customers in the sample, and from $0.20-$0.24/kWh for the SCE customers. Median bill savings are somewhat higher for the PG&E customers, because PG&E's retail rates are generally somewhat higher than SCE's (as shown previously in Figure 3), leading to a slightly higher average bill savings from PV.

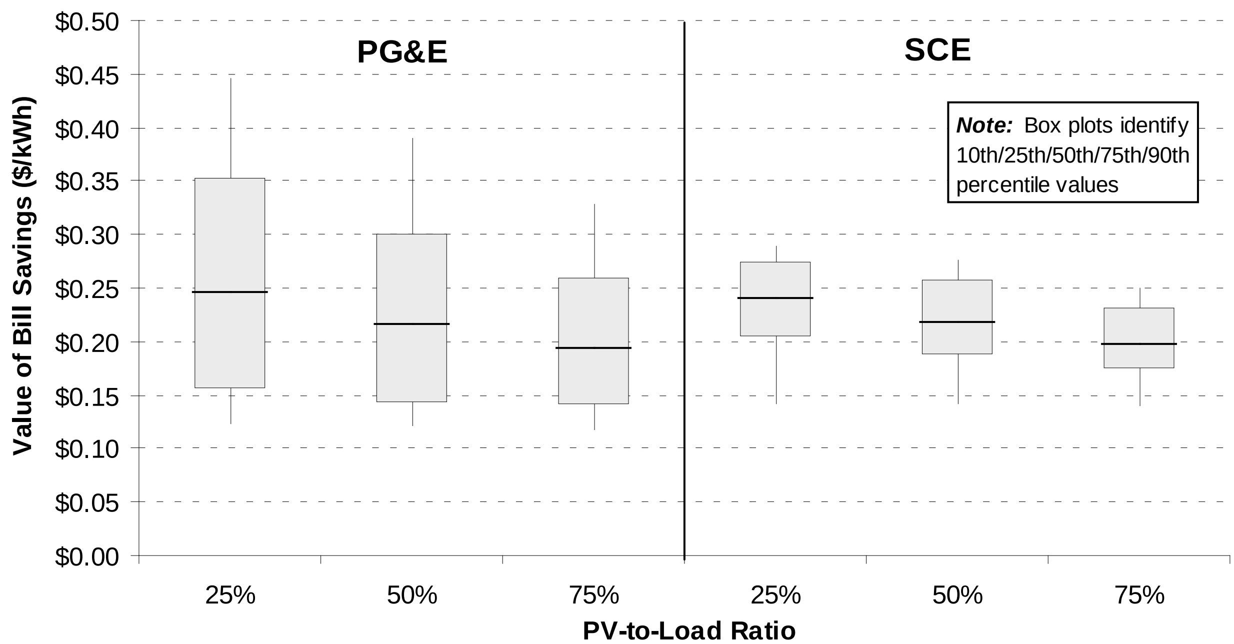

Figure 14. Distribution in Bill Savings under Net Metering and Base-Case Assumptions

As evident by the height of the box-plots in Figure 14, the value of the bill savings varies significantly across customers at each given PV-to-load ratio, though the distributions are substantially wider for PG&E than for SCE. This variation across customers is associated primarily with differences in customer usage level, where higher usage customers receive greater bill savings from PV by offsetting higher-priced usage within the upper usage tiers.

The specific relationship between the per-kWh value of bill savings and customer usage level is shown in Figure 15, which plots the value of bill savings for each customer against the customer's gross annual consumption (as a percent of the baseline allocation). For the PG&E customers in the sample, the value of bill savings increases steadily with customer consumption. At a 50% PV-to-load ratio, for example, the value rises from a low of approximately $0.12/kWh for customers in Tier 1 to $0.36-$0.46/kWh for customers in Tier 5. In contrast, the value of bill savings for the SCE customers in the sample increases at a much more gradual pace, and tapers off with increases in usage above the Tier 5 threshold: at a 50% PV-to-load ratio, the bill savings for the SCE customers in the sample rises from approximately $0.14/kWh for customers in Tier 1 to $0.24-0.29/kWh for customers in Tier 5. The differing trend between the two utilities is a result of differences between their retail rate structures – specifically, the fact that SCE's flat rate has less steep usage tiers than PG&E's, and that SCE's TOU rate has only two usage tiers, while PG&E's has five. Consequently, high-usage SCE customers face a significantly lower marginal price for their usage than do PG&E customers, resulting in lower bill savings from net metered PV for those customers.

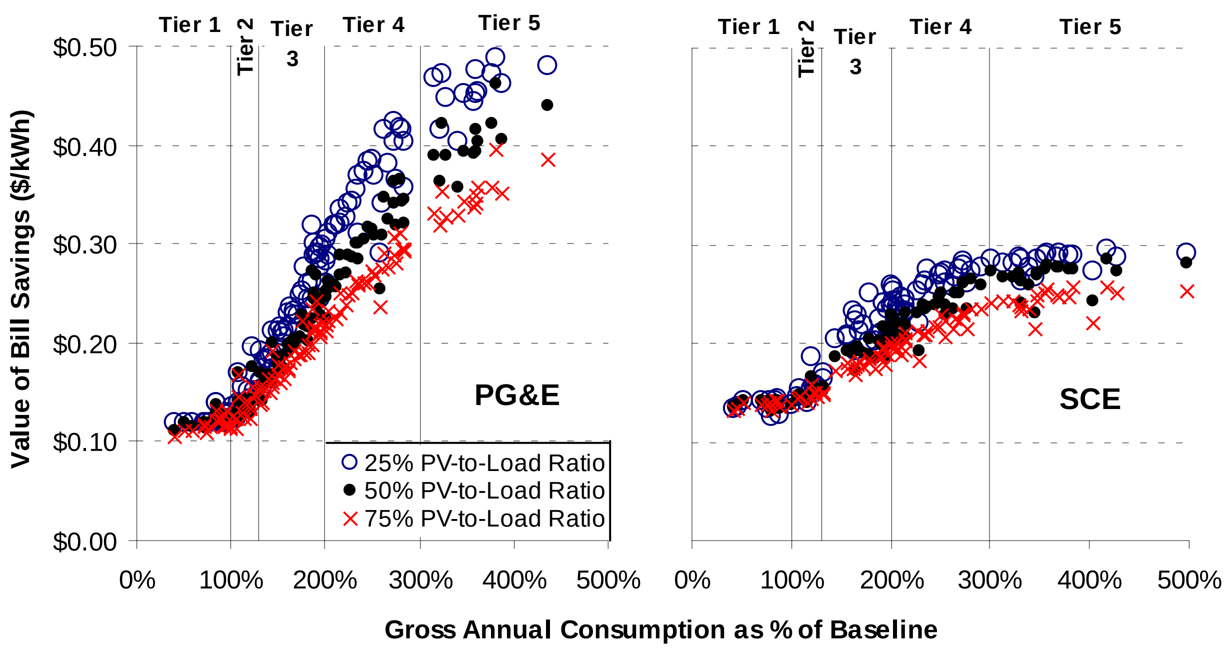

Figure 15. Variation in Bill Savings with Customer Gross Annual Consumption

The fact that bill savings value increases with customer consumption has an important implication for the applicability of the results to the population of net metered residential customers in California. As described earlier in Section 2.2.3, the average consumption of customers in the data sample is significantly lower than the average consumption of the actual population of residential customers with PV in California. As such, though the analysis is still valid in presenting the bill savings impacts of PV over a range of residential customer characteristics, it likely understates the median bill savings for the actual population of residential customers in California with net metered PV.

Another key trend exhibited in Figure 14 is that the per-kWh value of bill savings declines with an increasing PV-to-load ratio. This trend is also illustrated in Figure 13 by the downward shift in the per-kWh bill savings for each customer, with each successive increase in the PV-to-load ratio. This decline occurs for the simple reason that incremental increases in PV production offset consumption in progressively lower-priced usage tiers. As such, the decline in the per-kWh value of bill savings with PV-to-load ratio is particularly pronounced for the high-usage PG&E customers in the sample, as these customers progress through a larger number of lower-priced usage tiers than would a lower-usage customer that starts from a lower initial tier. This can be seen in the precipitous drop in the upper tail of the PG&E distribution in Figure 14, where the 90th percentile value of bill savings declines from $0.45/kWh to $0.33/kWh when the PV-to-load ratio increases from 25% to 75%. One does not observe the same magnitude of drop off for the SCE customers in the sample (for which the decline in the 90th percentile value of bill savings is from $0.29/kWh to $0.25/kWh), primarily because the majority of the SCE customers in the sample with PV are found to minimize their bill by taking service under the TOU rate, which has only two usage tiers, and also because the usage tiers under SCE's flat rate are significantly less steep than under PG&E's flat rate.

2.4.2 Net Metering Sensitivity Analyses

Two sensitivity analyses were conducted to examine how deviations from the base-case assumptions affect the value of bill savings from PV under net metering. The first sensitivity analysis examines the impact of sub-optimal rate choice, and illustrates the importance of proper rate selection for customers seeking to maximize the value of the bill savings from their PV system. The second sensitivity analysis examines alternate PV panel orientations, showing that, under certain circumstances, the alternate PV orientations can lead to a slightly higher bill savings on a per-kWh basis, although the absolute dollar magnitude of the bill savings produced by such systems may be lower due to reduced annual PV production per kW of installed capacity.

2.4.2.1 Impact of Sub-Optimal Rate Choice on Bill Savings

The base case analysis assumed that customers chose the lowest cost rate before and after installation of their PV systems. Given that customers may not always choose the least-cost rate, however, the value of bill savings were also calculated assuming that all customers choose the most expensive rate after PV installation, but continue to select the least-cost rate prior to PV installation.[24] This combination of assumptions results in the lowest value of bill savings possible, among the various combinations of assumptions about rate choices, and thus helps to illustrate both the significance of the base-case assumption, as well, more generally, the importance of proper rate selection for customers with net metered PV.

For each customer, the *difference* between the value of the bill savings under the worst-case rate selection assumptions and under the least-cost (i.e., base-case) rate selection assumptions were calculated. Figure 16 shows the distribution, across customers, in the difference in value of the bill savings between these two cases, at varying PV-to-load ratios. The values are thus negative, as sub-optimal rate selection causes a reduction in the bill savings value.

[24] There is some evidence that, in fact, many PV customers do not select the least-cost rate – or more specifically, that customers remain on the flat rate rather than switching to TOU, even if doing so would reduce their bill. Energy and Environmental Economics (2010) identifies the actual rate choice of net metered PG&E and SCE customers, indicating that approximately 13% of the residential PG&E customers and 4% of the SCE customers appear to be taking service on a TOU rate. Although the PV-to-load ratio for these customers is not known, the analysis suggests that the TOU rates likely would be the least-cost option for a much larger fraction of these customers.

In general, the results indicate that sub-optimal rate selection can have a sizable impact on the value of the bill savings for some customers at low PV-to-load ratios, but has a relatively modest effect at higher PV-to-load ratios. Specifically, at a 25% PV-to-load ratio, the median reduction in bill savings resulting from sub-optimal rate selection is $0.028/kWh (or an 11% decrease) and $0.021/kWh (a 10% decrease) for the PG&E and SCE customers in the sample, respectively. However, the distributions at a 25% PV-to-load ratio are wide, with some customers – in particular, those with particularly flat or peaky load profiles who would be much better off on one rate than on the other – experiencing a substantially greater loss of bill savings. For example, one-quarter of the PG&E customers in the sample would experience a decline of $0.049/kWh (23%) or more, and one-quarter of the SCE customers would see a decline of $0.039/kWh (17%) or more.

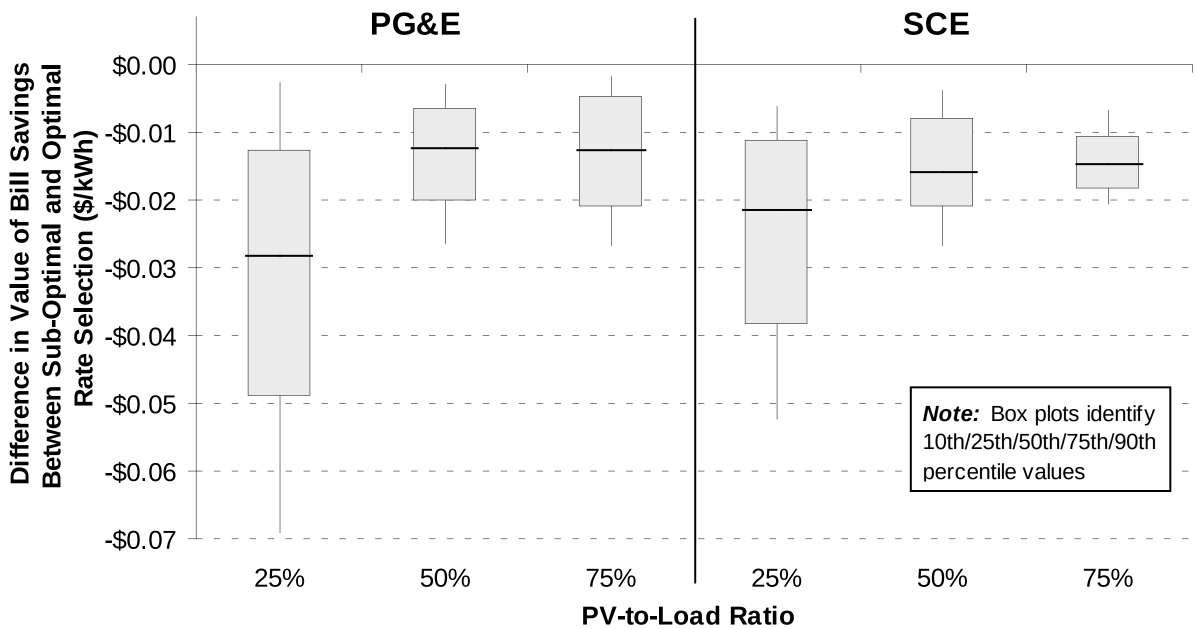

Figure 16. Distribution in the Effect of Sub-Optimal Rate Selection on the Value of Bill Savings

At higher PV-to-load ratios, the impact of sub-optimal rate selection on the value of bill savings is diminished. This is fundamentally a mathematical phenomenon: at higher PV-to-load ratios, customers' net consumption, and thus their exposure to retail rates, is lower, reducing the absolute dollar impact of the choice between rate options. At the same time, the amount of PV generation is greater, reducing the dollar impact per kWh generated even further. Thus, for PG&E customers, the median loss in bill savings associated with improper post-PV rate selection declines to $0.012/kWh (a 5% decrease) and $0.013/kWh (6%) at 50% and 75% PV-to-load ratios, respectively. For SCE customers, the median loss in bill savings declines to $0.016/kWh (a 7% decrease) and $0.015/kWh (7%) at 50% and 75% PV-to-load ratios. However, this assumes that customers were making the least-cost choice before installation of PV, which is not necessarily correct. If customers were making poor choices before PV, then the difference in the bill savings with the suboptimal choice after introduction of PV would be greater, even at larger PV-to-load ratios.

2.4.2.2 Impact of PV Panel Orientation on Bill Savings

The results presented in Section 2.4.1 assumed that PV panels were facing due-south at a 25° tilt. To test the effect of alternate PV orientations, the per-kWh value of bill savings for systems facing at an azimuth of 240° (approximately west-southwest) with a 25° tilt were also calculated, as well as for systems with no tilt (i.e. mounted flat on a non-sloping rooftop). Figure 17shows the difference in the per-kWh value of the bill savings between each alternative PV orientation and the base-case orientation. In general, the difference in bill savings between alternate PV orientations is quite modest – in most cases, less than $0.01/kWh or 5% – and can be either positive or negative. For most PG&E customers, the flat orientation results in slightly lower bill savings per kWh than the base-case orientation, particularly at low PV-to-load ratios, while the southwest-facing system generally results in higher per-kWh bill savings than the base-case orientation. For SCE customers, both alternate orientations generally yield higher per-kWh bill savings than the base-case orientation.

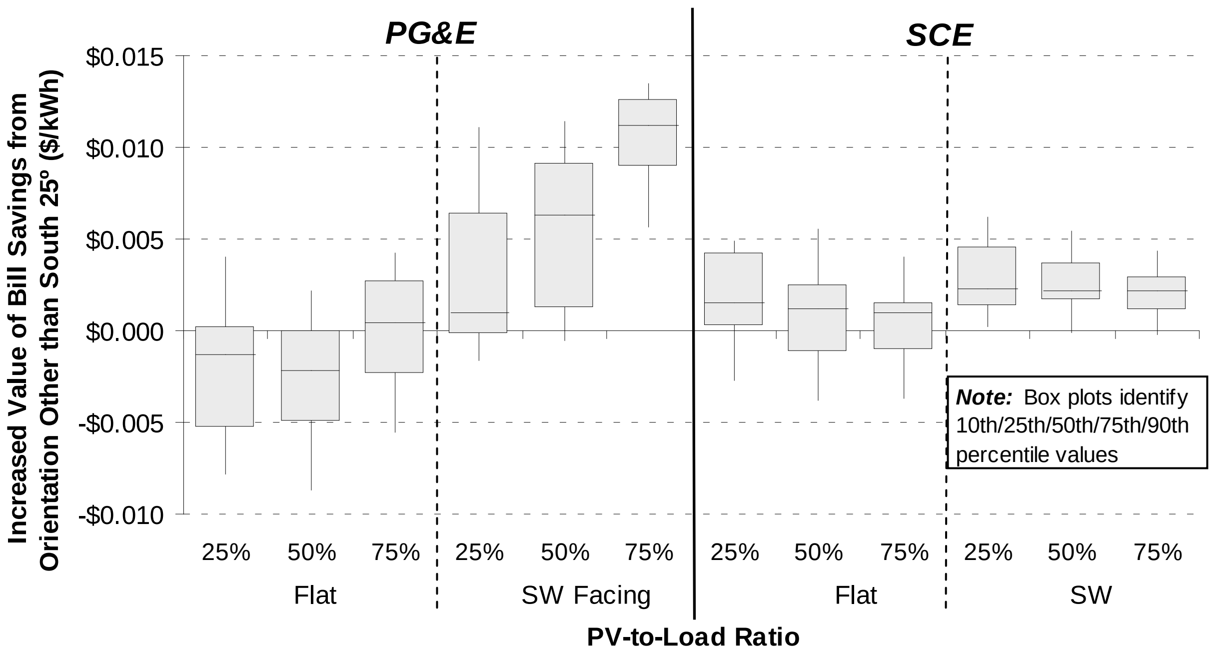

Figure 17. Difference in Bill Savings between Alternate and Base-Case PV Orientations

To be clear, the comparisons presented in Figure 17 are intended only to illustrate whether deviations from the base-case PV panel orientation would significantly alter the results. These comparisons do not, however, indicate which orientation would produce a greater *absolute* level of bill savings (in terms of the total dollar reduction in annual utility bills), as the quantity of PV electricity production also varies among orientations. In the median case, the west-southwest orientation results in 11% less PV electricity production than the south-facing orientation, and the flat PV orientation results in 10% less electricity production. These effects are, in fact, much more significant than the change in the per-kWh value of the bill savings across the three PV panel orientations, and imply that, for most customers, the absolute dollar amount of bill savings would be lower under the alternative PV panel orientations than under the base-case orientation, irrespective of the changes in the per-kWh value of bill savings shown in Figure 17.

2.4.3 Impact of Changes to SCE's TOU Rates on the Bill Savings under Net Metering

One feature of net metering is that the bill savings can change over time as a result of changes to the underlying retail rate. As an illustration, the impact of changes to SCE's residential TOU rates at the end of 2009 was considered.[25] Prior to October 2009, SCE offered two TOU rates to residential customers, schedules TOU-D-1 and TOU-D-2, which are now closed to new customers (though still available for customers that were already enrolled). Unlike the new TOU-D-T rate, the old TOU rates had no usage tiers,[26] which provided a strong incentive for high-usage customers to opt for a TOU rate and thereby avoid the high-priced usage tiers under the flat rate.

To characterize the impact of this revision to SCE's residential TOU rates on net metered PV customers, for each SCE customer in the sample, the bill savings under the pre-October 2009 set of rate options – assuming, as usual, that customers choose the least-cost rate option available – were calculated and compared to the bill savings under the current set of rate options (i.e., the base-case results, presented earlier).[27] **Figure** 18 shows the *difference* in the value of bill savings, for each customer, under the current set of rate options and under the pre-October 2009 rate options. Thus, a positive value indicates that the current rate options result in higher bill savings.

In the median case, the impact is small, with most customers receiving bill savings that are approximately $0.01-$0.02/kWh greater under the current set of rate options. However, for high-usage customers, the current set of rate options appears to result in a fairly sizable increase in the value of the bill savings. This is because, under the previous set of rate options, high-usage SCE customers without PV systems are found to opt for one of the TOU rate options, in order to avoid the high-priced usage tiers under the flat rate. Because the new TOU rate includes usage tiers, utility bills for high-usage customers without PV systems are higher, which in turn results in a larger decrease in the utility bills after a PV system is installed. Separate from that dynamic, the introduction of usage tiers in the TOU rate also results in an increase in utility bills at high PV-to-load ratios, as the incremental PV generation tends to displace usage in the lower-priced usage tier. Consequently, the difference in the value of the bill savings between the current and old set of rate options tends to diminish at higher PV-to-load ratios.

[25] Of note, PG&E recently proposed a major revision to its residential retail rates, under which Tiers 3, 4, and 5 would be combined into a single usage tier, and baseline allotments would be reduced. Although this rate proposal is not analysed here, it would likely have a significant impact on the value of the bill savings received by high-usage customers with net metered PV systems.

[26] Schedule-TOU-D-1 does, however, offer a discount of $0.035/kWh for usage within the baseline tier.

[27] To be clear, in one case, customers are assumed to select the least cost option (both before and after PV installation) among the flat rate and the two old TOU rates, and in the other case, between the flat rate and the current TOU rate. In reality, customers that were previously taking service on one of the old TOU rates could switch to the new TOU rate; however, for simplicity, this combination of choices was not included within the analysis.

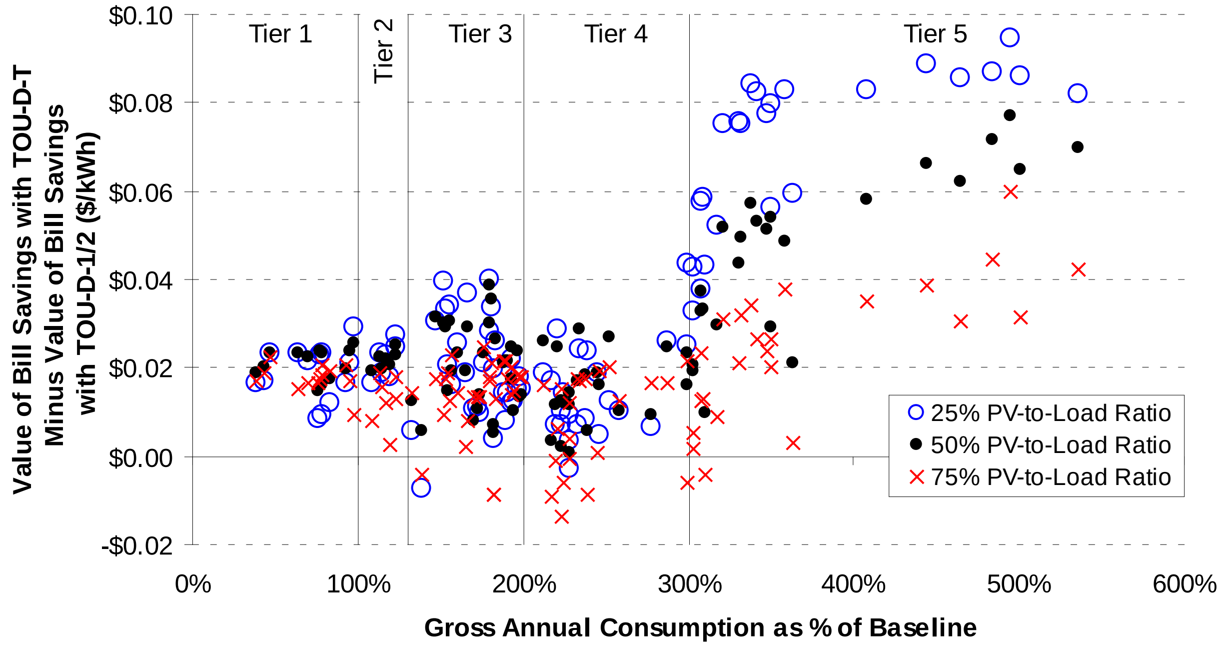

Figure **18**. Difference in Bill Savings between Current and Old SCE Rate Options

2.4.4 Maximum PV Size to Exhaust Annual Bill Savings

The net metering tariffs in place as of March 2010 allow customers to offset all volumetric energy charges over the course of year, but any excess bill credits remaining at year-end are forfeited by the customer.[28] As discussed previously in Chapter 3, at relatively high PV-to-load ratios, most PG&E and SCE customers would minimize their utility bill on the TOU rate option. Because PV production is typically more highly concentrated during high-priced TOU periods than is customer consumption, most customers would therefore exhaust their annual bill savings with a PV system that is sized to meet less than 100% of their annual consumption.

Figure 19 presents cumulative frequency distributions showing the percentage of customers that would exhaust their annual bill savings at varying PV-to-load ratios As shown, 86% of the PG&E customers in the sample, and 97% of the SCE customers would exhaust their bill savings with PV systems sized to meet less than 100% of their annual usage. In the median case, the PG&E customers exhaust their bill savings at a PV-to-load ratio of 93%, and the SCE customers do so at a PV-to-load ratio of 92%.

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

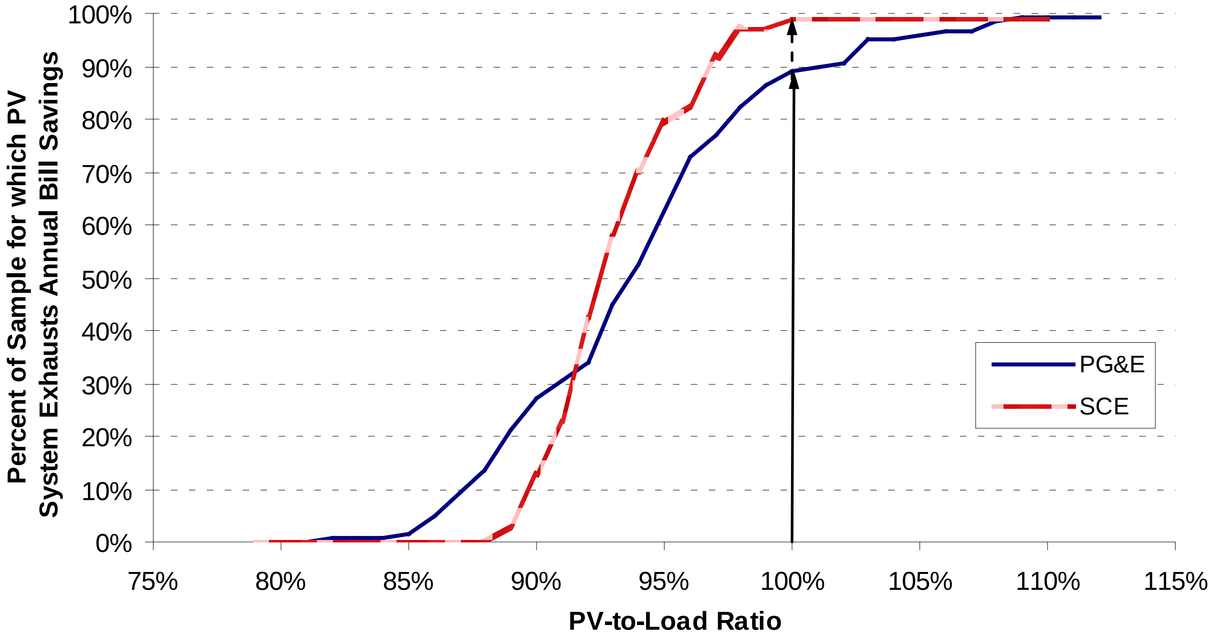

Figure 19. PV System Size that Exhausts Annual Bill Savings

2.5 Bill Savings under Alternative PV Compensation Mechanisms

In this chapter, the bill savings between net metering and each of three alternative compensation mechanisms were compared, under which some or all PV generation is compensated at prices based on the state's Market Price Referent (MPR), rather than at the customer's retail rate.[29] These three alternatives are:

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

The first two of these alternative compensation mechanisms are similar – though not identical – to compensation options currently offered though California's small renewable generator feed-in tariff program.[30] The third alternative is a variant of net metering that exists in

[29] Net metered customers in California are exempt from interconnection fees. In comparing the bill savings between net metering and the alternative compensation mechanisms, no difference in interconnection costs or other ancillary costs of participation (e.g., meter costs) is assumed born by the customer.

[30] California's small renewable generator feed-in tariff program is available to certain solar and other renewable generation projects smaller than 1.5 MW. That program, which provides an alternative to net metering, provides customers with the option to either sell all electricity generated by their system under an MPR-based feed-in tariff or to use their renewable generator to first meet on-site load and sell only the excess generation to the utility under the feed-in tariff. Under the latter, "excess sales" option, excess generation may be computed on a sub-hourly basis.

a number of states, under which customers receive payment for monthly excess generation at an avoided cost based rate, rather than rolling the net excess generation forward to the following month and thereby receiving compensation at retail electricity prices. The MPR-based prices paid under each of these alternatives are based on the 2009 MPR prices (CPUC 2009). However, MPR prices are adjusted annually and are based in part on contemporaneous long-term projections of natural gas prices, which can change significantly from year to year; thus, any comparison between the bill savings under net metering and under MPR-based alternatives is also subject to such fluctuation.

Although these three options are reasonable points of comparison to the existing net metering tariffs in California, they by no means represent the universe of possible alternatives, either in terms of pricing or structure. With respect to pricing, the MPR-based price paid for excess PV production under each of these alternatives reflects only avoided generation costs. Cost-benefit analyses of distributed PV often identify other benefits to utilities and ratepayer, including, though not limited to, deferred T&D capacity upgrades and reduced line losses. As such, the MPR arguably represents a lower-bound on the value of distributed PV production to the utility and ratepayers. Although the range of other possible benefits of distributed PV were not comprehensively examined, at the end of this chapter, the potential impact of increasing the prices paid under the alternative compensation mechanisms to reflect avoided T&D costs and reduced line losses is explored.

The comparisons presented in this chapter between net metering and the alternative compensation mechanisms focus primarily on the *pre-tax* value of the bill savings or payments for net excess generation. However, unlike the bill savings that customers receive through net metering, explicit payments or bill credits provided to customers for generation exported to the grid may be subject to federal and state income taxes. In that case, customers may then also be able depreciate the capital costs of their PV system, thereby offsetting, at least in part, taxes assessed on electricity sales. Given that these tax effects are somewhat uncertain, comparing bill savings primarily on a pre-tax basis was opted for. However, as a “worst-case” scenario, comparisons are also presented under the assumption that customers are taxed for electricity sales but do not depreciate the capital cost of their PV system.

2.5.1 Net Excess PV Production

Under the hourly and monthly netting options, only a portion of PV production – the hourly or monthly net excess PV generation, respectively – is compensated at MPR-based prices rather than at the retail rate. Figure 20 shows the portion of annual PV production subject to MPR-based prices (i.e., total annual net excess generation as a percentage of total annual generation), based on all PG&E and SCE customers in the sample combined. Net excess generation is computed in three different ways: on an hourly basis (for the hourly netting option), a monthly TOU-period basis (for customers on a TOU rate under the monthly netting option), or a simple monthly basis (for customers on a flat rate under the monthly netting option).

Within the analysis, however, the smallest time interval over which excess generation is computed is an hourly basis, as that is the time resolution of the source of simulated PV generation data.

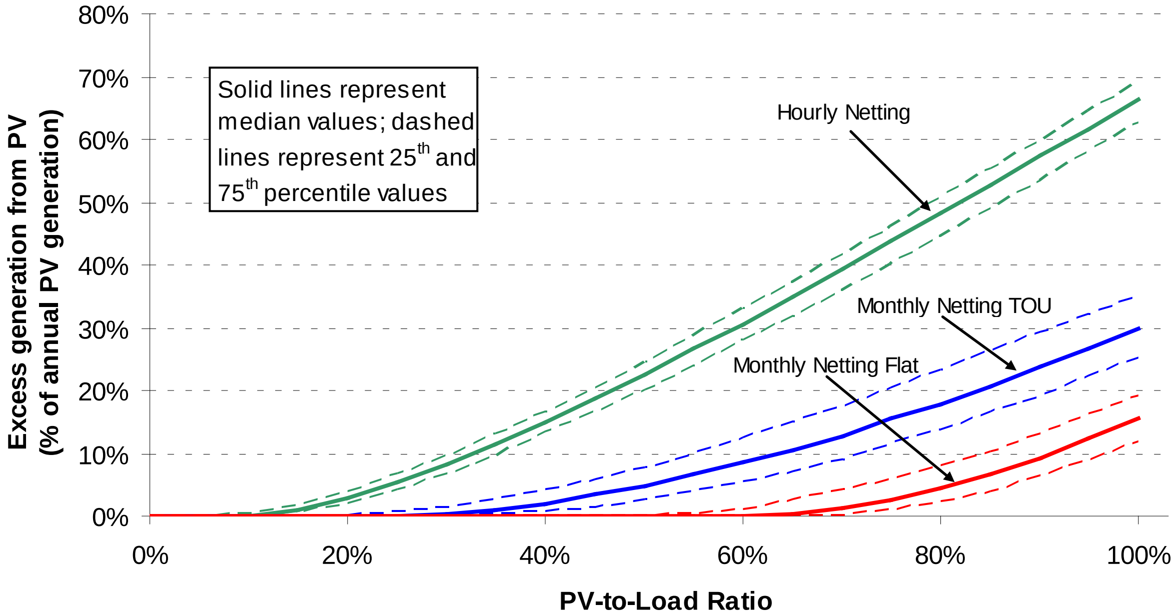

Figure 20. Annual Net Excess PV Generation under Hourly and Monthly Netting Options

As to be expected, annual net excess PV generation as a percentage of total generation rises with the PV-to-load ratio, and is greatest under hourly netting and least under simple monthly netting for customers on a flat rate. With hourly netting, net excess generation begins to occur at a PV-to-load ratio of roughly 10% (in the median case), rising to approximately 5% of total annual PV generation at a 25% PV-to-load ratio and to 44% at a 75% PV-to-load ratio. For monthly-TOU netting, net excess generation begins to occur at PV-to-load ratios greater than about 30%, reaching 15% of total PV generation at a 75% PV-to-load ratio. Finally, when calculated on a simple monthly basis for customers on a flat rate, net excess generation occurs only at PV-to-load ratios greater than about 65%, reaching just 3% of total annual PV generation at a 75% PV-to-load ratio. From this analysis, one can see that, with monthly netting, a relatively small portion of PV generation is compensated in a different manner than under net metering.

2.5.2 Least-Cost Rate Choice under Alternative Compensation Mechanisms

Bill savings under the hourly and monthly netting options depend in part on customer rate choices, just as under net metering. As in the net metering analysis, customers are assumed to take service under the least-cost rate option, both before and after PV installation. Figure 21 identifies, for each compensation mechanism and across PV-to-load ratios, the percentage of customers for which the TOU rate would be the least-cost option.

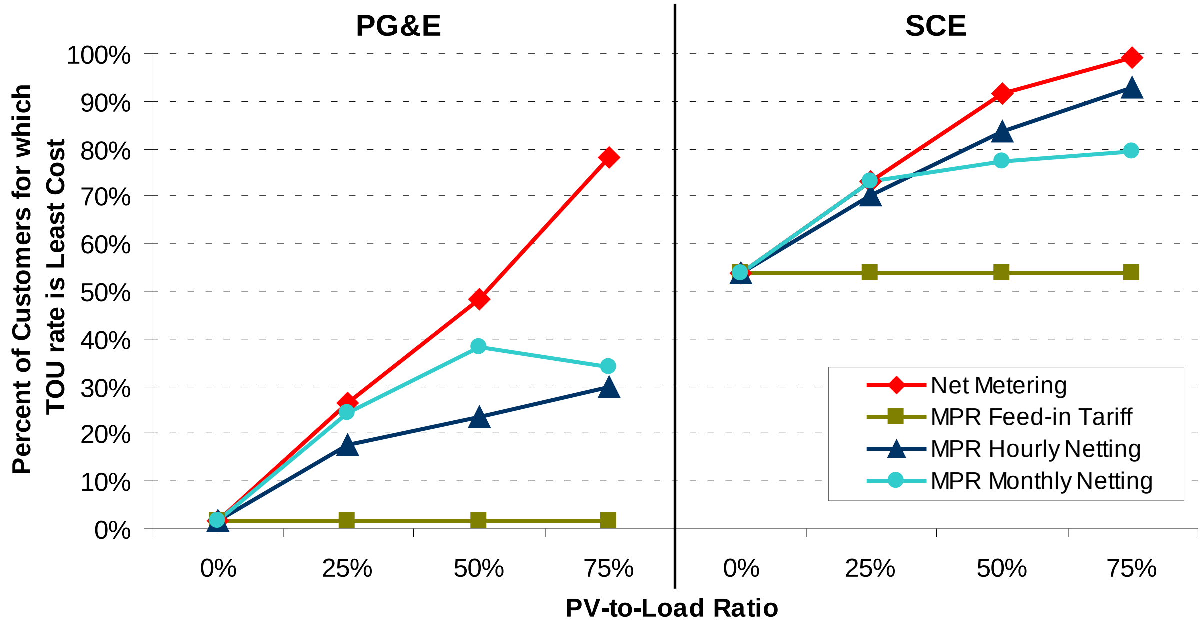

Figure 21. Least-Cost Rate Choice under Alternative PV Compensation Mechanisms

In general, the results show that, under the alternative compensation mechanisms, customers' least-cost rate choice is less dependent on the PV-to-load ratio and, consequently, TOU rates are the least-cost rate option for a smaller percentage of customers than under net metering. Under the full MPR-based feed-in tariff, the least-cost rate is, as one would expect, wholly independent of the PV-to-load ratio and is therefore simply based on whatever the least-cost rate was in the case of no PV. Under the hourly and monthly netting options, an increasing percentage of customers find the TOU rate to be the least-cost option at higher PV-to-load ratios, the same as under net metering; however, the trend towards TOU with increasing PV-to-load ratio is dampened. TOU rates are somewhat less valuable under the hourly and monthly netting options, because net excess PV production occurs disproportionately in the summer peak period, and thus a smaller fraction of the total PV production is credited at the summer peak TOU period retail price under hourly and monthly netting than under net metering.[31]

[31] Figure 21 exhibits a number of other trends as well. First, under monthly netting, the percentage of PG&E customers for which the TOU rate is least-cost decreases slightly from a 50% to a 75% PV-to-load ratio. This occurs because monthly net excess generation is lower under the flat rate than under the TOU rate (as shown previously in Figure 20), allowing a larger percentage of PV production to be compensated at retail rates, rather than at the MPR-based rate. Because the retail rate is higher than the MPR, this tends to make the flat rate more attractive. Second, for SCE, the TOU rate is least-cost for a larger percentage of customers with hourly netting than with monthly netting for customers with a 50% and 75% PV-to-load ratio, while the reverse it true for PG&E. This difference ultimately derives from the fact that, with monthly netting, the TOU rate results in larger amounts of net excess generation during winter peak periods, and SCE's MPR-based price during the winter peak period is much lower than its retail rates, which tends to make the flat rate somewhat more attractive under monthly netting.

2.5.3 Comparison of Bill Savings between Net Metering and Alternative Compensation Mechanisms

With the previous results as background, for each customer, the bill savings under each of the alternative compensation mechanisms and at each PV-to-load ratio are calculated, and compared to the bill savings under net metering. Key findings of this analysis are summarized below, for each alternative compensation mechanism in turn.

2.5.3.1 MPR-Based Feed-In Tariff

Figure 22(a) presents the distribution, across customers in the sample, of the value of the bill savings under the full MPR-based feed-in tariff. As shown, under the full MPR-based feed-in tariff, the median value of the bill savings (or feed-in tariff payment, as the case may be) from PV is approximately $0.12/kWh for the PG&E customers in the sample, and $0.13/kWh for the SCE customers, with little variation across customers or across PV-to-load ratios.

Figure 22(b) presents the distribution in the *difference* between the bill savings value under the MPR-based feed-in tariff and under net metering; thus, negative values indicate that the bill savings under a particular alternative are lower than under net metering. For most customers, the bill savings received through the MPR-based feed in tariff are substantially lower than under net metering, and the reduction in bill savings is greatest for high-usage customers (especially high-usage PG&E customers), who receive the largest bill savings under net metering. Specifically, among the PG&E customers in the sample, the median reduction in bill savings under the MPR-based feed-in tariff, relative to net metering, ranges from $0.08-$0.13/kWh (a 40%-54% reduction) across the PV-to-load ratios examined. For the quartile of PG&E customers with the highest usage, however, the reduction in bill savings exceeds $0.14-$0.23/kWh (55%-67%) across the PV-to-load ratios. Among the SCE customers in the sample, the median reduction in bill savings under the MPR-based feed-in tariff, relative to net metering, ranges from $0.07-$0.11/kWh (34%-46%) across the PV-to-load ratios. The difference in bill savings between the MPR-based feed-in tariff and net metering is less for SCE than for PG&E, primarily because the bill savings under net metering are generally lower for the SCE customers than for the PG&E customers, particularly for high-usage customers.[32]

[32] In addition, SCE's MPR rate has a higher summer on-peak TOD adjustment factor than PG&E, which tends to make MPR-based compensation more attractive for SCE customers than for PG&E customers. However, this effect is offset to some extent by other differences between the two utilities' MPR-TOD structures (e.g., PG&E has three MPR seasons, while SCE has two, and PG&E's Summer Super-Peak period spans a wider set of hours than SCE's Summer Super-Peak).

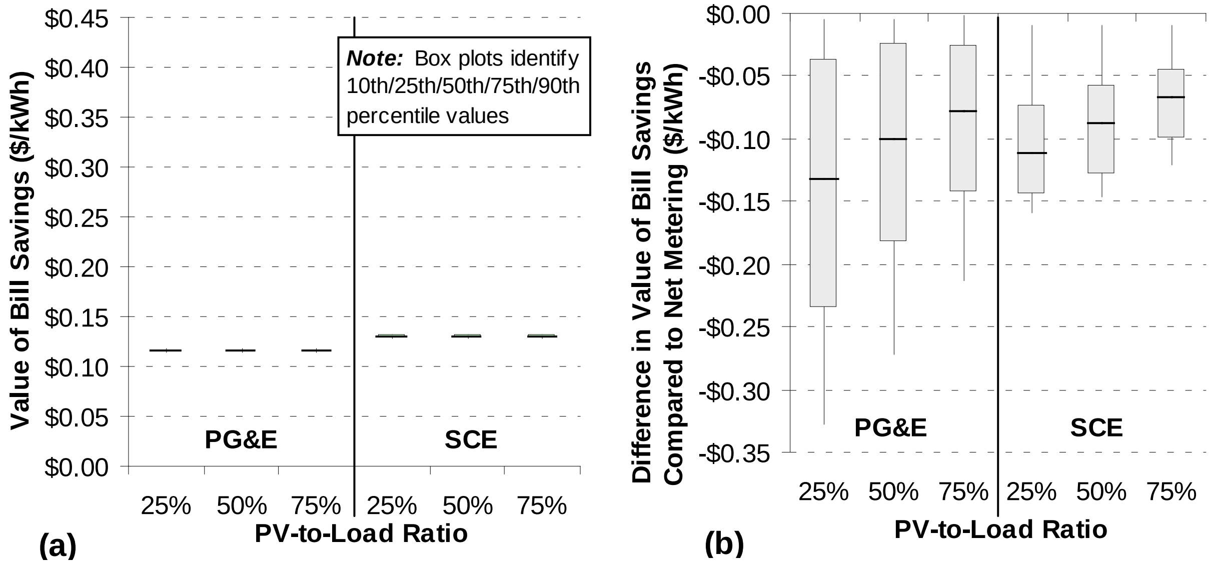

Figure 22. Distribution in Bill Savings under the MPR-Based Feed-In Tariff and the Change in Bill Savings Relative to Net Metering

For a customer with PV to be indifferent between the full MPR-based feed-in tariff and net metering, the average price paid for PV generation under the feed-in tariff would therefore need to be higher than the average MPR-based price, by an amount equal to the difference in the value of bill savings between the two options, as shown in Figure 22(b). Thus, for the median PG&E customer in the sample, the feed-in tariff price would need to be $0.13/kWh higher than the average MPR-based price at a 25% PV-to-load ratio and $0.08/kWh higher at a 75% PV-to-load ratio.[33] Similarly, for the median SCE customer in the sample, the feed-in tariff price would need to be $0.11/kWh higher than the average MPR-based price at a 25% PV-to-load ratio and $0.07/kWh higher at a 75% PV-to-load ratio.

The preceding results are based on the *pre-tax* value of the bill savings under the MPR-based feed-in tariff. If one were to assume that all compensation provided through the MPR-based feed-in tariff were subject to state and federal income tax, however, and that customers do not take advantage of the corresponding opportunity to depreciate the capital cost of their PV system, then the difference between the *after-tax* value of the bill savings provided under net metering and under the MPR-based feed-in tariff would be $0.043-$0.048/kWh greater in the median case. Specifically, among the PG&E customers in the sample, the median difference in the after-tax value of bill savings would be $0.175/kWh at a 25% PV-to-load ratio and $0.121/kWh at a 75% PV-to-load ratio, compared to a pre-tax difference of $0.132/kWh and $0.078/kWh, respectively. Similarly, among the SCE customers in the sample, the median difference in the after-tax value of bill savings would be $0.160/kWh at a 25% PV-to-load ratio and $0.116/kWh at a 75% PV-to-load ratio, compared to a pre-tax difference of $0.112/kWh and $0.067/kWh, respectively.

[33] To be clear, these values effectively represent the size of the "adder" that would need to be included in the price paid for each kWh of PV generation under the feed-in tariff, in order for the median customer to be indifferent between the feed-in tariff and net metering. The adder does not represent the increase in the baseload MPR price that would be required to achieve that outcome.

2.5.3.2 MPR-Based Hourly Netting

Under the hourly netting option, the total bill savings for any individual customer is equal to the sum of the bill savings from offsetting hourly consumption at retail prices and the bill credits for hourly net excess generation as compensated at the applicable MPR rate. As shown in Figure 23(a), the median bill savings for the PG&E customers in the sample is approximately $0.23/kWh at a 25% PV-to-load ratio, declining to $0.17/kWh at a 75% PV-to-load ratio. For SCE customers, the median bill savings ranges from $0.23/kWh at a 25% PV-to-load ratio to $0.18/kWh at a 75% PV-to-load ratio.

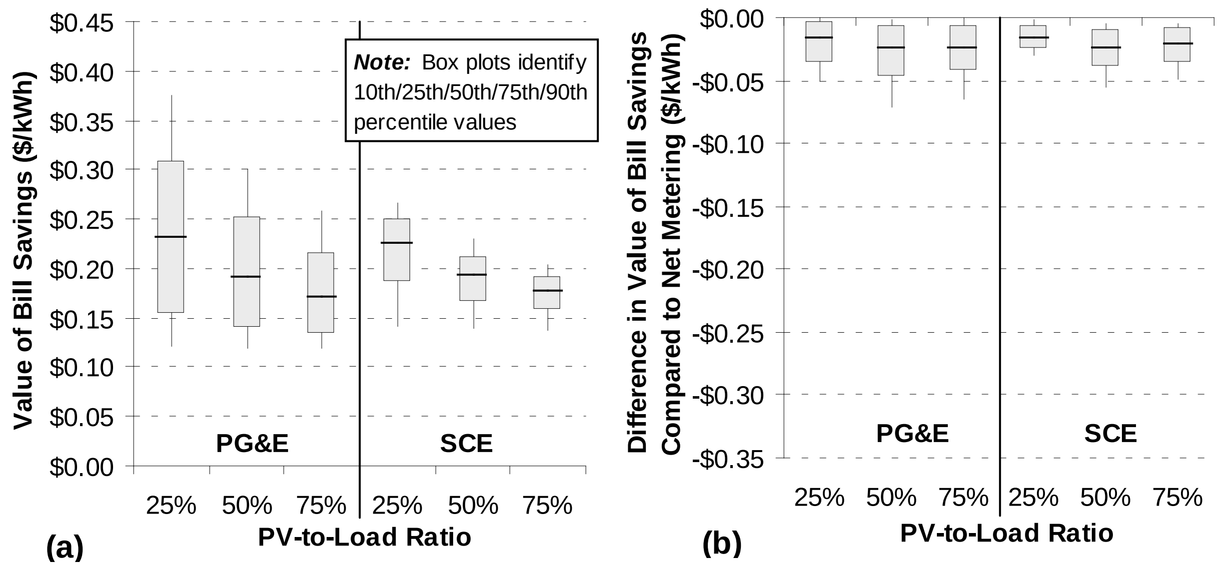

Figure 23. Distribution in Bill Savings under MPR-Based Hourly Netting and the Change in Bill Savings Relative to Net Metering

Customers of both utilities would generally experience a reduction in bill savings under hourly netting, relative to net metering, but the difference is significantly less than under the full MPR-based feed-in tariff. As shown in Figure 23(b), the median reduction in bill savings relative to net metering is, among the PG&E customers in the sample, approximately $0.015/kWh at a 25% PV-to-load ratio (about a 6% reduction in bill savings), increasing to $0.024/kWh (or 12%) reduction at a 75% PV-to-load ratio. For the SCE customers, the median reduction in bill savings ranges from $0.016/kWh (6%) to $0.021/kWh (11%) over this range in PV-to-load ratios. Furthermore, unlike the full MPR-based feed-in tariff, the reduction in bill savings is not significantly greater for high-usage customers than for other customers in the sample, as demonstrated by the tighter range of results shown in Figure 23(b), compared to Figure 22(b).

The difference in the bill savings between net metering and MPR-based hourly netting derives specifically from the difference in the value of the bill credits provided for hourly excess generation. As shown in Figure 24, under MPR-based hourly netting, the median value of the bill credits for hourly excess generation is about $0.12/kWh across all PV-to-load ratios and for the customers of both utilities in the sample. In comparison, the median value of the bill credits for hourly excess generation under net metering ranges from $0.15-$0.18/kWh for the PG&E customers, and from $0.16-$0.21/kWh for the SCE customers in the sample, across the three PV-to-load ratios.[34]

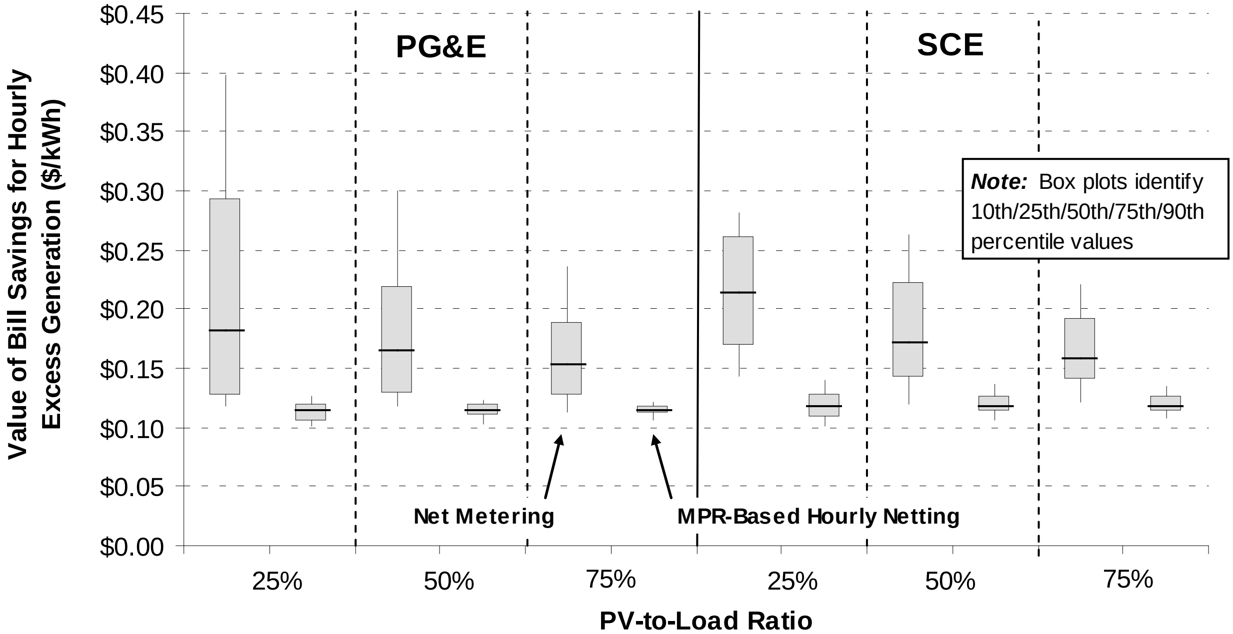

Figure 24. Comparison of Bill Credits for Hourly Excess Generation under Net Metering and MPR-Based Hourly Netting

Higher prices for hourly net excess generation would therefore be required for most customers within the sample to be indifferent between hourly netting and net metering. Among PG&E customers in the sample, the price for hourly net excess generation would, in the median case, need to be increased above the current average MPR-based price by approximately $0.07/kWh at a 25% PV-to-load ratio and $0.04/kWh at a 75% PV-to-load ratio. Similarly, for the SCE customers in the sample, the price for hourly net excess generation would, in the median case, need to be increased above the current average MPR-based price by approximately $0.09/kWh at a 25% PV-to-load ratio and $0.04/kWh at a 75% PV-to-load ratio.

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

The preceding results are based on the *pre-tax* value of the bill savings under the hourly netting option. If one were to assume that payments or bill credits provided for hourly net excess generation were subject to state and federal income tax, however, and that customers do not take advantage of any corresponding opportunity to depreciate the capital cost of their PV system, then the difference between the *after-tax* value of the bill savings provided under net metering and under MPR-based hourly netting would be approximately $0.007-$0.026/kWh greater in the median case. Specifically, among the PG&E customers in the sample, the median difference in the after-tax value of bill savings would be $0.028/kWh at a 25% PV-to-load ratio and $0.049/kWh at a 75% PV-to-load ratio, compared to the pre-tax difference of $0.015/kWh and $0.024/kWh, respectively. Similarly, among the SCE customers in the sample, the median difference in the after-tax value of bill savings would be $0.023/kWh at a 25% PV-to-load ratio and $0.046/kWh at a 75% PV-to-load ratio, compared to the pre-tax difference of $0.016/kWh and $0.021/kWh, respectively.

2.5.3.3 MPR-Based Monthly Netting

Last, under the MPR-based monthly netting option, the value of the bill savings is only marginally different than under net metering (see Figure 25(b)). Specifically, the reduction in bill savings relative to net metering is zero (or approximately zero) at low PV-to-load ratios, and slightly greater at higher PV-to-load ratios (i.e., a median loss of less than $0.01/kWh at 75% PV-to-load ratio, for both the PG&E and SCE customers in the sample). The difference between the value of the bill savings under net metering and under monthly netting is small for two reasons. First, and most obviously, the portion of PV generation that is compensated differently between the two options is quite small, as shown earlier in Figure 20. Second, under net metering, monthly excess PV production is effectively credited at Tier 1 prices, which differ only slightly from the MPR-based prices.

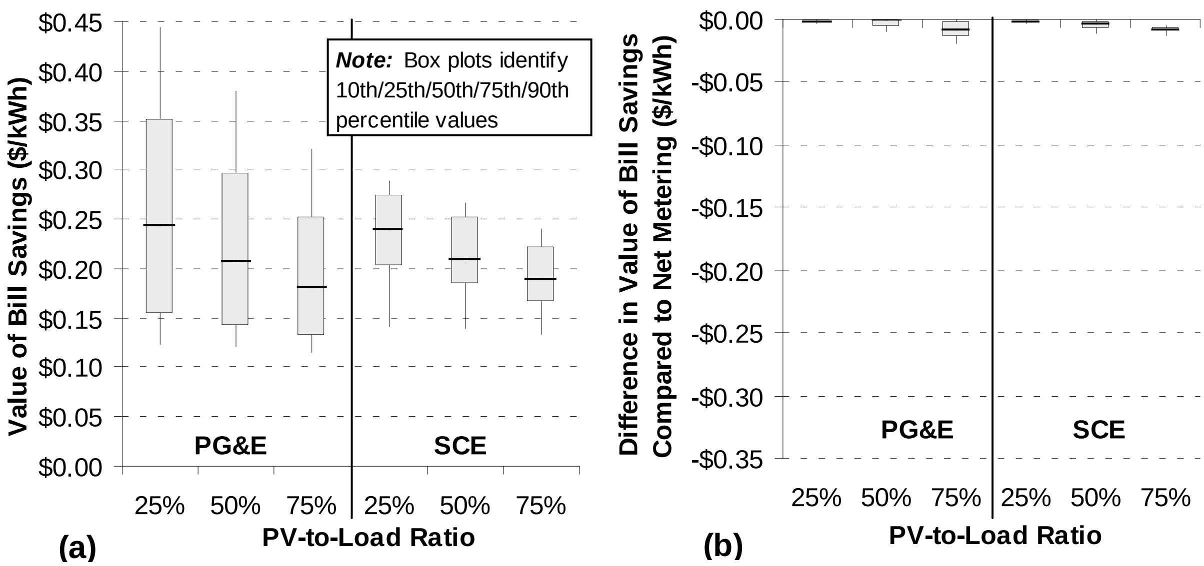

Figure 25. Distribution in Bill Savings under MPR-Based Monthly Netting and the Change in Bill Savings Relative to Net Metering

2.5.4 The Potential Bill Savings Impact of Accounting for Avoided T&D Costs and Reduced Line Losses

The preceding comparisons were based on alternative compensation mechanisms with prices based on the MPR, which is intended to represent the long-run market price of electricity. However, distributed PV may result in additional avoided costs that could conceivably be incorporated into the price paid for PV generation under these compensation mechanisms. Here, the results of other studies that have attempted to estimate two specific additional sources of avoided costs – deferred T&D capacity upgrades and reduced line losses – are reviewed and the potential impact of incorporating these avoided costs into the alternative compensation mechanisms analyzed in the preceding sections is considered. Cost-benefit studies of distributed PV have, in some cases, included other, additional benefits; however, the analysis here is limited solely to avoided T&D costs and reduced line losses.[35]

First, with respect to T&D capacity deferrals, one inherent challenge to incorporating the associated avoided costs into a PV compensation mechanism is that they are highly idiosyncratic and depend on the specific location of each individual PV system, the quantity of PV installed, the point in time that it is installed, and the temporal correlation between PV generation and peak demand on the T&D systems. Various studies have evaluated the benefit of T&D capacity deferrals from distributed PV, a sub-set of which are summarized in Table 6. These studies evaluate T&D capacity deferrals under two fundamentally different types of situations. The first set of studies focuses on T&D capacity upgrades that would be required to meet load growth but are deferred as a result of distributed PV. The range in avoided costs, both within and across this class of studies, is wide, ranging from less than $0.001/kWh to more than $0.04/kWh. This variation reflects differences in underlying economic drivers (e.g., load growth, the cost of T&D capacity, solar insolation, PV system configuration, etc.), as well as methodological differences among the studies. The other set of studies in Table 6, instead, address the avoided costs from distributed PV that may occur as a result of deferring long-distance transmission that would otherwise be required to access remote renewable resources. Kahn (2008) focuses on the specific case of the proposed Sunrise Transmission Link into San Diego; based on his analysis, the benefit provided by distributed PV in deferring construction of that line ranges from approximately $0.057-$0.132/kWh. This range is considerably higher than the unit cost of the transmission line per kWh delivered, which Kahn (2008) estimates to be $0.035/kWh.[36] In other contexts, however, the avoided cost value of deferring transmission may be more closely approximated by the unit cost of transmission per kWh of renewable energy delivered, which Mills *et al.* (2009) and Mills *et al.* (2010) report as ranging from $0.005-$0.062/kWh and from $0.008-$0.032/kWh, respectively.

However it is estimated, including a "T&D adder" in the alternative compensation mechanisms considered previously, in order to account for the value of deferred T&D capacity, would close the gap between the bill savings provided through those mechanisms and net

[35] For example, distributed PV may provide a hedge against fuel price risk (i.e. it "locks in" a fixed cost of energy over the long term) and environmental regulation risks (i.e. it does note emit carbon or other emissions at point of use). Hoff *et al.* (2006) also estimate benefits provided in the form of reduced disaster recovery costs to the utility.

[36] The reason for this divergence is that Kahn (2008) effectively assumes that each kW of distributed PV capacity (adjusted for transmission losses) displaces a kW of transmission capacity, rather than assuming that each kWh of distributed PV generation displaces a kWh of remote renewable generation.

metering.[37] However, the significance of the effect naturally depends on the avoided cost value assumed, which, as Table 6 indicates, could vary by more than two orders of magnitude. For example, a T&D adder of $0.01/kWh would reduce the median pre-tax difference in bill savings between net metering and the *full MPR-based feed-in tariff* by 8%-13% for the PG&E customers in the sample and by 9-15% for the SCE customers, across the range of PV-to-load ratios examined (see Table 5). A T&D adder of this magnitude would reduce the median difference in bill savings between net metering and the *hourly netting* option by 13%-26% for the PG&E customers in the sample and by 10%-23% for the SCE customers, across the range of PV-to-load ratios examined. The impact of a larger T&D adder would be proportional to the increase in the size of the adder (i.e., a doubling of the T&D adder to $0.02/kWh would yield effects twice the size of the percentage values identified in Table 5).

Table 5. Reduction in the Median Loss of Bill Savings Relative to Net Metering if Avoided T&D Costs and Line Losses Are Included in the Price for Net Excess Generation

	PV-to-Load Ratio					
	PG&E			**SCE**		
	25%	**50%**	**75%**	**25%**	**50%**	**75%**
Avoided T&D Costs of $0.01/kWh						
Full Feed-in Tariff	8%	10%	13%	9%	11%	15%
Hourly Netting	13%	19%	26%	10%	15%	23%
Avoided Line Losses (10% loss factor)						
Full Feed-in Tariff	9%	11%	15%	12%	15%	19%
Hourly Netting	15%	21%	29%	13%	17%	30%

The values in the table represent the median percentage reduction, across customers in the sample, in the difference between the value of the bill savings under net metering and under the alternative compensation mechanisms, if the price paid for net excess generation under the alternative compensation mechanisms incorporated avoided T&D costs and avoided line losses, at the illustrative levels shown.

Distributed PV also results in reduced T&D line losses to the extent that the electricity generated is consumed onsite or nearby (e.g., within the same distribution feeder). In general, line losses vary by utility system and by time of day, with higher losses during peak hours. For PG&E and SCE, T&D line losses range from 6-11%, depending on the season and time of use period (E3, 2010a). Accounting for reduced line losses within the alternative compensation

[37] It should be noted that there is some logical inconsistency in applying to the MPR an "avoided T&D cost adder" that is based specifically on the avoided cost of long-distance transmission to access remote renewable resources. Use of the MPR is predicated on the assumption that the avoided generation is a CCGT. If one posits that distributed PV is deferring long-distance transmission to access remote renewables, then avoided generation costs should arguably be based on the cost of the renewable resources that would be connected to the deferred transmission line.

mechanisms can be achieved by applying a line loss multiplier (e.g., 110% if losses are 10%) to PV generation that is compensated at MPR-based prices, rather than used to offset customer consumption. A multiplier of 110% would reduce the median pre-tax difference in bill savings between net metering and the *full MPR-based feed-in tariff* by 9%-15% for the PG&E customers in the sample and by 11%-19% for the SCE customers, across the range of PV-to-load ratios examined (see Table 5). A line loss multiplier of this magnitude would reduce the median difference in bill savings between net metering and the *hourly netting* option by 15%-29% for the PG&E customers in the sample and by 13%-30% for the SCE customers, across the range of PV-to-load ratios examined.

Table 6. Estimates of Avoided T&D Costs from Distributed PV

Study	Value of Avoided T&D Costs ($/kWh)	Notes
Deferred T&D Capacity Upgrades for Load Growth		
Energy and Environmental Economics (2010)	$0.013/kWh	The study estimates the value of avoided costs associated with T&D capacity deferral to the California IOUs. The value cited in this table represents the average value for residential net metered customers of PG&E and SCE.
Sollar Alliance *et al.* (2008)	$0.006-$0.044/kWh (PG&E) $0.023-$0.037/kWh (SCE)	The study estimates avoided T&D costs for PV systems in California, using the E3 avoided cost calculator. The range in values reflects differences across climate zones. Note that the E3 calculator was developed for the purpose of evaluating avoided costs from energy efficiency programs, not distributed PV.
Hoff, T. *et al.* (2006)	$0.001-$0.002/kWh	The study estimates the value of avoided costs associated with T&D capacity deferral to Austin Energy (AE), the municipal utility serving Austin, TX. The range in values corresponds to different distribution planning areas. The study notes that the calculated T&D deferral benefit is lower at AE than at other municipal utilities, because AE reports particularly low levels of potentially-deferrable T&D upgrades.
Hoff, T. *et al.* (2003)	$0.005-$0.037/kWh	The study estimates the value of T&D capacity deferral to Nevada Power. The range reflects differences across planning areas and PV system configurations (fixed-axis or single-axis). The study reports the NPV of avoided costs on a $/kW basis; those values were converted here to levelized $/kWh by dividing by the discounted lifetime kWh produced by a 1 kW system.
Passey et al. (2007)	$0.008/kWh	The study estimates the value of T&D deferral for the Western Australian electricity networks and regional grids.
Contreras et al. (2008)	$0.001-$0.10/kWh	Literature review. Value range depends on the location and the output during peak T&D times.
R.W. Beck, Inc. (2009)	$0-$0.008/kWh	The study estimates the value of avoided costs associated with T&D capacity deferral for various PV deployment scenarios within the service territory of Arizona Public Service Company.

Ong (2012)	$0.04/kWh	This analysis is Michigan specific, and reviews the results from four studies.
Deferred Transmission Capacity Upgrades for Accessing Remote Renewable Resources		
Kahn (2008)	$0.057-$0.132/kWh (transmission capacity and line losses)	The study estimates the value of avoided transmission capacity costs for PV systems installed in San Diego, based on cost of the proposed Sunrise Transmission Project. The range in avoided cost estimates reflects differing discount rates and assumptions about the length of time over which transmission capacity could be deferred. The study reports the dollar value of avoided costs for a 10 kW PV system located in San Diego; those values were converted here to $/kWh by dividing by the discounted lifetime kWh produced such a system.
Mills *et al.* (2009)	$0.005-$0.062/kWh	The study compiles the results from a large number of transmission expansion studies for accessing remote wind resources. The values cited here refer to the levelized cost per unit of delivered energy among studies of transmission projects to deliver wind energy to California utilities.
Mills *et al.* (2010)	$0.008-$0.032/kWh	The study developed estimates of the transmission capacity additions and costs required to meet a 33% RPS throughout the Western Interconnect. The values cited here refer to the levelized cost per unit of delivered energy, of the marginal transmission capacity resource required to meet the 33% requirement; the range in values reflects variation across California load zones.

2.6 Conclusions and Policy Implications

Net metering, in combination with other policy support mechanisms, has been instrumental in jump-starting the market for distributed PV in California and elsewhere in the U.S. The primary benefit that net metering bestows upon customers with distributed PV is that it allows the customer to offset its consumption with PV generation, independent of the temporal coincidence between consumption and generation.[38] This provides customers with greater flexibility in the sizing of their system and eliminates the uncertainty that would otherwise exist if customers could only offset their instantaneous consumption and received no compensation for generation exported to the grid. Although similar benefits might be obtained through wholesale electricity sales (e.g., a feed-in tariff), net metering arguably involves lower transaction costs for the customer and may be more amenable to participation by small, individual residential customers.

[38] In addition, net metering customers in California are exempt from interconnection fees.

One inherent feature of net metering, however, is that the bill savings received by the customer are highly dependent on the underlying retail rate structure. The current residential electricity tariffs offered by PG&E and SCE are relatively unique in their steeply-sloping inclined usage tiers. As a result, the bill savings for net-metered residential PV customers in these utilities' service territories varies widely across customers (by a factor of 4-5 for the PG&E customers in the sample and by a factor 2-3 for the SCE customers), depending on the customer's usage level and the relative size of the PV system. Though this level of variation in bill savings across customers and PV system sizes is relatively unique to California (and, specifically, to the current retail tariffs offered by the state's investor-owned utilities), it demonstrates the sensitivity of the bill savings value of net metered PV to the underlying rate structure.

In the early stages of market development, variation in bill savings across customers may serve a useful purpose by providing relatively high levels of compensation for a sub-set of customers and thereby fostering early adoption. In the long-run, however, large differences in the compensation provided for distributed PV across customers may be more problematic. First, from a social welfare perspective, the *variation* in bill savings occurring under the particular net metering and retail rates currently offered by PG&E and SCE arguably has little or no economic justification – that is, a PV system installed by a high-usage customer does not provide higher value to society than a PV system installed by a low-usage customer, nor does a kWh produced by a small distributed PV system necessarily provide higher value than one produced by a larger system.[39] Second, the degree of variability across customers observed for the two utilities may introduce complexity and uncertainty for customers considering a potential investment in distributed PV. Many residential customers may not possess the analytical know-how, for example, let alone the necessary data, to accurately forecast the bill savings that they would receive under the current set of residential retail rates and net metering rules offered by the two utilities. Perhaps as important, retail rate structures are subject to change over the life of a PV system, introducing further uncertainty for a customer considering a long-term PV investment. Of course, any alternative to net metering may also entail complexity and uncertainty for the customer and, in the end, the relative levels of complexity and uncertainty and the implications therein must be weighed against one another.

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

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

in tariff may also involve a number of other advantages or disadvantages (financial and otherwise) that are not addressed in this dissertation.

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

Chapter 3 SHORT TERM IMPACTS OF SOLAR GENERATION ON WHOLESALE ELECTRICITY PRICES IN CALIFORNIA: THE MERIT-ORDER EFFECT

3.1 Introduction

In chapter 2, I quantified how electricity bill savings are impacted by retail rate design, using retail rates available to residential customer in California in 2009. However, as electricity market conditions are changing, it's likely that wholesale price profiles will change in levels and shapes, trickling down to changes in retail rates (and the value of bill savings from PV). In this chapter, I investigate the potential change in wholesale market prices from a single change in electricity market conditions: increased PV penetrations, studying the merit-order effect. The merit-order effect is the reduction of wholesale prices by the introduction of low marginal cost generation (i.e. PV generation) which displaces more expensive generation, potentially changing the marginal generation and hence reducing the wholesale price of electricity. This analysis demonstrates how changes in wholesale market characteristics – using higher PV penetrations as an example – may impact wholesale price profiles (and hence retail electricity rates). However, though this method demonstrates that changes in wholesale market characteristics can have a sizeable impact on wholesale market prices (particularly their temporal profiles), it has a number of limitations that indicate that a model that accounts for capacity expansion and operational constraints would more accurately portray future wholesale electricity price profiles and trends, motivating the use of such a model in Chapter 4.

3.1.1 Chapter outline

The remainder of the introduction provides background on electricity markets and the merit-order effect, followed by the objectives for this chapter. Section 3.2 introduces the data used in this analysis – the hourly California Independent System Operator's (CAISO) electricity bid data and simulated PV generation data. I then describe the methodology in section 3.3, which involves constructing California PV generation profiles and developing the CAISO electricity bids from the raw data. The results are presented in section 3.4, and the conclusions and limitations of this analysis are discussed in section 3.5.

3.1.2 The merit-order effect and relevant literature

The merit-order effect, introduced in section 1.1.1, is a framework I use for analyzing the short-term impact of solar generation on wholesale electricity prices, which has been used in the literature to explore such affects. The merit-order curve is essentially the supply curve for wholesale electricity generation, arranging available generation in order of increasing marginal electricity costs. Adding PV generation to the merit-order curve adds zero-marginal cost units to the curve, effectively shifting the curve to the right. The impact of the shift in the merit-order curve is to reduce the optimal price, as shown in Figure 1 in Chapter 1, assuming a monotonically increasing merit-order curve. The steeper the curve at the point of intersection with the demand curve, the larger the price impact of PV generation.

The work presented in this chapter builds on broader literature investigating the short-term effects of solar on wholesale electricity prices. Most directly relevant is the literature investigating merit-order effect of renewable generation, notably Sensfuß et al. (2008), which investigates the merit-order effect of renewable generation in Germany. In Sensfuß et al. (2008), the demand curve is shifted in by the amount of solar generation, to create a residual demand curve. This approach finds an equivalent price to when the supply curve is shifted to the right by the amount of renewable generation. The authors conduct a sensitivity analysis, to understand how various scenarios would change the generation mix and impact the supply curve in the long term. Changes in the supply curve result in changes in the price effects of zero marginal cost generation. Others, such as O'Mahoney and Denny (2011), have used this methodology to simulate short-term price effects of renewable electricity generation. A richer literature has utilized other methods to study the price effects of renewables in the wholesale electricity market, such as Lamont (2008), Sáenz de Miera et al. (2008), and Mills and Wiser (2012), which are reviewed in section 1.1.1.

3.1.3 Objectives and boundaries

In this chapter, I simulate the merit-order effects of adding varying levels of PV penetrations to the CAISO market, studying its short-term impact on wholesale prices assuming no changes to the generator and load bids. This method to study the wholesale price impacts of zero-marginal cost PV is likely to over-estimate these impacts. In the long term, one would expect some low marginal cost baseload plants to retire and be replaced by more flexible and higher marginal cost combined cycle natural gas plants, which would make the supply curve steeper earlier, and result in higher prices than those calculated by using today's supply curve to determine the merit-order effect of PV generation. However, short of using a long-term capacity investment and dispatch model, using current bid stacks demonstrates that a sufficient capacity of solar generation in a balancing area *can* impact wholesale market prices. Throughout the analysis, the state of California will be used as the geographical area of interest. Not only is California a likely candidate for achieving high penetration of solar electricity generation before other regions given its aggressive GHG reduction policies, but current load and generation data for California is readily available. The CAISO publishes detailed data on hourly and sub-hourly bids in its day-ahead and real-time markets, the forecast levels of demand, and market results data. Market bid data is available online through the CAISO's Open Access Same-Time Information System (OASIS).

The first exploratory scenarios will quantify the impact of an increasing percentage penetration (up to 10%) of PV generation on wholesale electricity prices assuming the current generation mix in California. Using the OASIS website to download bid data, supply and demand bid stacks for every hour in the period from April 1, 2009 to December 31, 2010 can be derived. Hourly solar generation profiles can be introduced into the bid stacks to calculate effective prices. A detailed methodology is presented in section 3.3.2. This analysis is meant to show that PV generation, at a sufficiently large penetration, can impact wholesale electricity prices.

Results of this study are not meant to forecast what will happen in California's future electricity markets, but instead this is meant to be a preliminary, conceptual analysis. It's more of an exercise to enhance the understanding of the dynamics underlying price changes in the electricity market than it is a forecast for what may happen when PV generation reaches higher penetrations in CA. It's also a way for me to rationalize the use of a longer-term capacity investment and dispatch model in Chapter 4.

California and the CAISO are chosen as study areas, as the CAISO provides one of the most comprehensive data sets to reconstruct generation and load bid curves, and California has a commitment to higher levels of renewables, as per its renewable portfolio standard. Recognizing that California will likely be more integrated into the Western Electricity Coordinating Council (WECC) region with increased transmission to and from neighboring states, one may question the use of studying the merit order effect solely on California. However, the merit order I use is based on bids into the CAISO market, and these bids already include import bids from neighboring states. Limited by existing transmission, which will most probably be enhanced in the coming years, these bids integrate generation in the wider WECC region, at least partially. Moreover, some neighboring states (particularly NV and AZ) are likely to have high PV penetrations as well, so the addition of import and export bids into these states may have a result somewhat similar to the California market (i.e. lower cost generation during times when PV generates electricity). The PV generation profiles will be slightly different that for California, namely, they will peak a bit earlier than California PV, and this would have an effect on (i.e. reduce) California wholesale prices before noon. Import and exports to the Pacific Northwest will have different characteristics, given that solar generation is not expected to be as prevalent in these regions. However, if we treat the Western region as an integrated region, this would roughly equate to a larger region with a lower effective PV penetration. Hence modeling results with a lower PV penetration would be applicable to a larger region with a lower effective PV penetration. If the region of study were WECC, geographic diversity of solar sites in California and other states would reduce the WECC-wide variability of solar generation, which would reduce integration costs of solar generation.

Further boundaries and limitations will be explored in the conclusions section (3.5).

3.2 Data

The principal sources of data are the CAISO's Open Access Same-time Information System (OASIS), freely available online (CAISO, 2012), a time series of state-wide solar output from the California Public Utility Commission's 33% Renewable Portfolio Standard (CPUC, 2010), the SolarAnywhere insolation database maintained by Clean Power Research (Clean Power Research, 2012), and weather data from the National Climatic Data Center (NOAA, 2012). Each of these is described in more detail below.

3.2.1 CAISO's OASIS data

CAISO maintains a web site that provides a wide variety of market results data, including actual prices, system-wide load, the bid stacks for generators and load each hour for all hours since April 2009 for the real-time and day-ahead markets at any node in the restructured CA market[40]. Four types of files were downloaded from OASIS: (a) actual load (one month of hourly

[40] For this analysis, data from the day-ahead market are used; all bids made in the day-ahead market are repeated in the real-time market, and "virtual" trades can be made from the day-ahead to the real-time market so that prices between the two markets tend to converge.

data per csv file); (b) day-ahead hourly market clearing (in-state) load and generation, total hourly exports and imports; (c) day-ahead market actual price (one month of hourly data per csv file); (d) day-ahead market generator, import/export bids, and load bids (one day of hourly data per file). A computer script, written in Perl, was written to download the large number of files. The actual and day-ahead load and price files include hourly load (or price) for each of the Investor-owned Utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric) as well as for the entire CAISO region. Only the data for the entire CAISO region is used in the analysis. The analysis makes use of the following bid data columns: Start time and date, end time, resource type (generator, load, or intertie), bid participant ID, market product type, self-schedule size (for price-takers, number of MW that bid participant will sell as generator or purchase as load at the market clearing price), and energy bid at determined price. From these, one can determine whether the bid is for generation or load, and whether the bid is price-taking, monotonically increasing (for generator bids) or monotonically decreasing (for load bids). The challenge with intertie bids is that the data provided by OASIS do not specify whether the bid is an import or export bid, which is necessary to build complete supply and demand curves. Some information can be deduced from the intertie bid, since monotonically increasing intertie bids are always generator bids and decreasing bids are always load bids, but this cannot be deduced for the self-schedule and single price bids. However, since total imports and exports are provided, one is able to deduce the self-scheduled amount through an iterative process of adding sufficient self-scheduled imports (or exports) in order to result in the day-ahead market price. The methodological details on how bids were constructed are found in section 3.3 below.

3.2.2 Solar insolation and PV generation data

To construct the state-wide solar generation profile for 2009 and 2010, I used a number of datasets including simulated 2020 solar generation output based on 2005 baseline load and insolation from a CPUC 33% Renewable Integration Study, and weather data from the National Oceanic and Atmospheric Administration's National Climatic Data Center. Though the methodology to reconstruct solar PV generation data for 2009 and 2010 is outlined in section 3.3, the data sets are described here.

The CPUC coordinated with the CAISO a 33% Renewable Integration Study, to understand the operational requirements and market impacts of a 33% renewable portfolio standard in California. As a part of this work, a number of solar sites were selected to simulate the solar PV and concentrating solar power (CSP) production in the target year 2020, but based on insolation and weather patterns of 2005. The simulated PV generation has a one-minute time resolution, and are freely available online (CAISO, 2010).

The final dataset used to construct a simulated 2009/2010 state-wide solar generation profile is insolation data for three sites in California for 2005, 2009, and 2010, from the National Oceanic and Atmospheric Administration's National Climatic Data Center site (NOAA, 2012). This data is used to match each day in 2009 and 2010 with a day in 2005 with a similar insolation profile. The three sites are Merced, Redding, and Stovepipe Wells, and were chosen to represent geographically diverse sites within CA in the northern, central, and southern parts of the state.

3.3 Methodology

The general methodology to model short-term price impacts is based on the shifting of economic electricity bids from 2009 and 20010 in the wholesale electricity market due to zero marginal cost solar generation, similar to that used in Sàenz et al. (2008) and Sensfuß et al. (2008). However, since 2009 and 2010 solar generation data is not readily available, I first need to reconstruct a solar generation profile for those years. The methodology for developing the solar generation profiles are outlined in section 3.3.1, and the process of reconstructing bids and determining the resulting shift in prices due to solar generation is described in section 3.3.2.

3.3.1 Constructing solar generation profiles for 2009 and 2010

The approach presented below is to match solar generation with total load, since these two are closely linked, particularly on the hot, sunny days, since California's peak load is often a result of air conditioning load in the summer. Since 2009 and 2010 solar generation data were not readily available, individual days from the simulated solar generation output from the CPUC's 33% Renewable Integration Study based on 2005 weather data were matched to each day of 2009 and 2010, by finding corresponding days that minimized the sum of square error of the daily insolation profiles between each day of 2009 and 2010 with each day of 2005. The minimization was implemented using a brute-force method; that is, a MATLAB script was written to loop through each day in 2009 and 2010 and compare each day of 2005 to find the corresponding insolation profile with the lowest sum of square error over all three sites considered. This method was used only to identify the most appropriate day match, using the insolation profiles from these three sites; the locational data used for the generation profiles are imbedded in the CPUC data, which is a weighted average over sites across CA (i.e. the solar generation data is not a function of the solar insolation from the three sites). A reconstructed solar generation profile was created using the mapping of dates (determined using insolation profiles); each day in 2009 and 2010 is mapped to a single day from 2005, and so the corresponding 2005 solar generation from the CPUC study was concatenated to recreate an hourly solar generation profile for the two years. For example, the 2005 insolation profile with the lowest sum of square error from December 17, 2009 is December 15, 2005, so the CPUC solar generation profile from December 15, 2005 is used for December 17, 2009. The corresponding date for December 18, 2009 is January 1, 2005, so the entire CPUC solar generation profile from January 1, 2005 is used for December 18, 2009, and so forth.[41] The resulting solar generation data is normalized using CAISO's total demand to the sought penetration level. Solar PV penetration is modeled from 1% through 10% in this analysis. I chose 10% as an upper bound in this analysis as this method displays major limitations for higher PV penetrations (discussed in the section 3.5).

[41] The fit between the modeled and actual insolation is particularly good for these two days; the difference between the modeled and actual insolation is greater for many days, due to the large diversity in profile shape combinations.

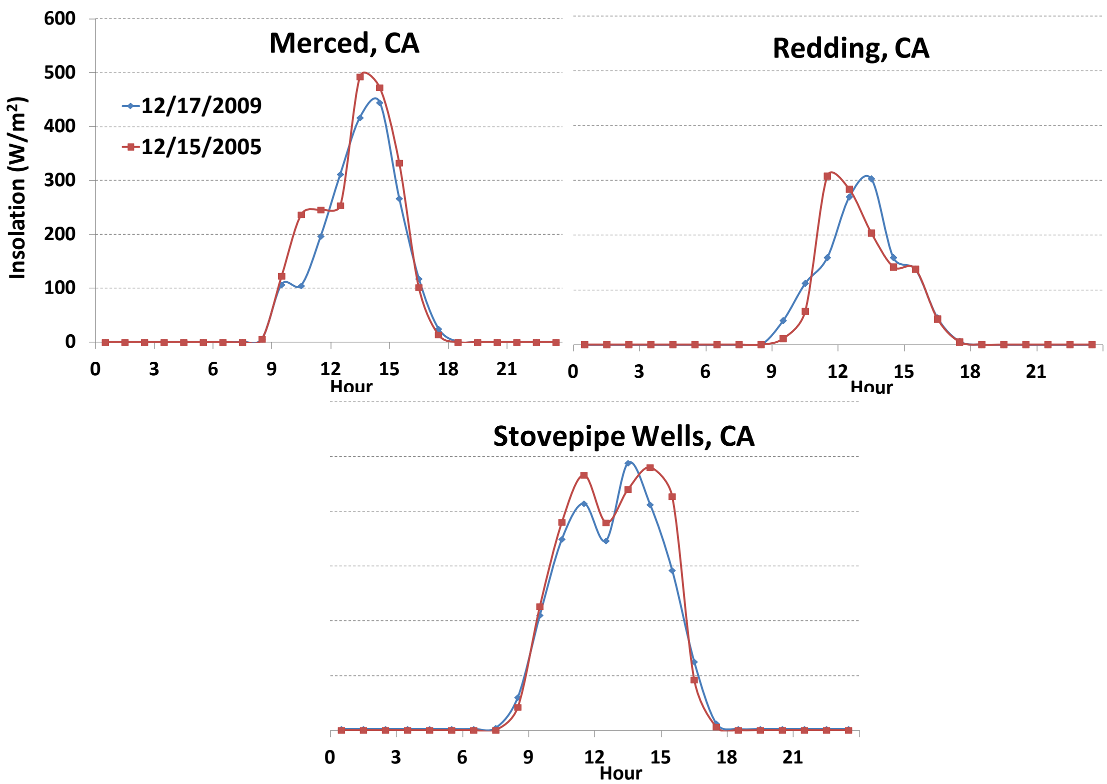

Figure 26. Matched insolation data for December 17, 2009.

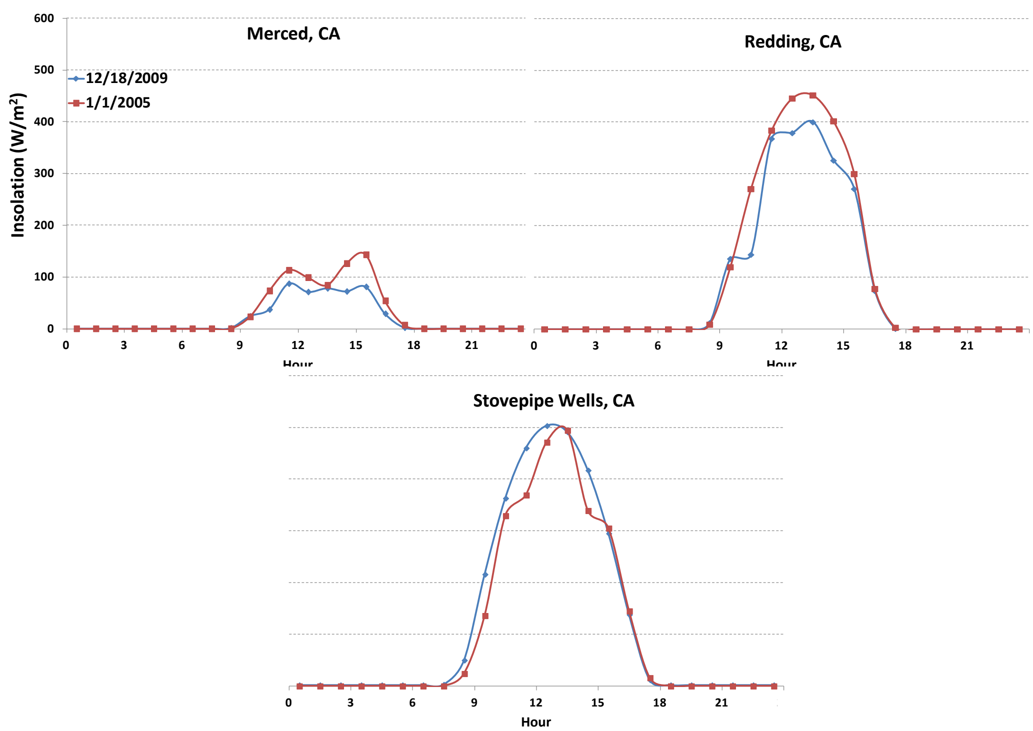

Figure 27. Matched insolation data for December 18, 2009.

3.3.2 Reconstructing supply and demand bid curves and calculating price impacts of solar

Using the CAISO's day-ahead market bid data, in addition to the hourly market clearing load, I recreated a supply and demand curve for electricity in the wholesale market for each hour of April 2009 through December 2010. The CAISO bid data consists of individual data entries for each point on the supply curve or demand curve, and are defined as a generator, load, or intertie point. Each participating load, generator, or intertie has a minimum of two data entries in the bid data (two point entries define a single price bid for a given range of MW). If there are more than two data entries for a given generator a given hour, this implies a monotonically increasing or decreasing bid (for supply/imports or demand/exports, respectively). The supply curve for any hour can be reconstructed from the hourly bid data by adding all generator and import bids, sorting them by increasing bids, and the demand curve can be reconstructed by adding all load and export bids, sorting them by decreasing bids. A number of bids are self-schedules, which implies that they are market price takers. These are entered as negative $100/MWh for supply (implying that self-scheduled supply would be willing to sell at any price above -$100/MWh) and $10,000/MWh for self-scheduled loads (implying that these load entities would be willing to pay any price up to $10,000/MWh for a given amount of load). The intertie bids are not specified as imports or exports, so this is inferred by the bid, if possible. Import bids are generators from outside the CAISO bidding into the CAISO bid pool, and export bids are loads from outside the CAISO (e.g. a utility in AZ which needs load in specific hours). If the intertie bid is monotonically increasing, then it is an import bid, and if the intertie bid is monotonically decreasing, it is an export bid. Single price bids that are higher than the highest supply bid that hour are assumed to be an export bid, and single price bids that are lower than the lowest bid are assumed to be import bids. These supply and demand curves are not complete, however, as the self-scheduled and single-price intertie bids are not included. These bids are not specified to be imports or exports, and hence the single-price intertie bids cannot be used. However, I use the day-ahead market clearing import and export data for that hour and adjust the supply and demand curves to the right as appropriate (hence assuming that all remaining imports and exports are self-scheduled).

An example supply and demand curve, constructed from CAISO bid data, is found in Figure 28 and Figure 29, for hours 0 and 12 on December 17, 2009. In these two examples, the self-scheduled demand (instate load + exports) is 19,762 MW and 25,233 MW for hours 0 and 12, respectively, and the self-scheduled supply (instate generation + imports) is 14,240 MW and 16,560 MW for hours 0 and 12, respectively. The market clearing price is $51.33/MWh and $58.59/MWh for hours 0 and 12, respectively, and the market clearing supply and demand is 21,115 and 27,059 MW for hours 0 and 12, respectively. Note that the slope of the supply curve is gentle from roughly above 15,000 MW to about 40,000 MW for hour 0 and 18,000 MW to about 40,000 MW for hour 12, resulting in small price increases with increased demand; even though the supply curve shifts outward from hour 0 to hour 12, the price increases 14% while the market-clearing load increases by over 28%.[42]

[42] Were load to fall below 15,000 MW in this example, prices would drop off precipitously due to the steepness of the lower part of the supply curve. The curve is steep on the lower end of supply curve resulting from min load and flexibility constraints.

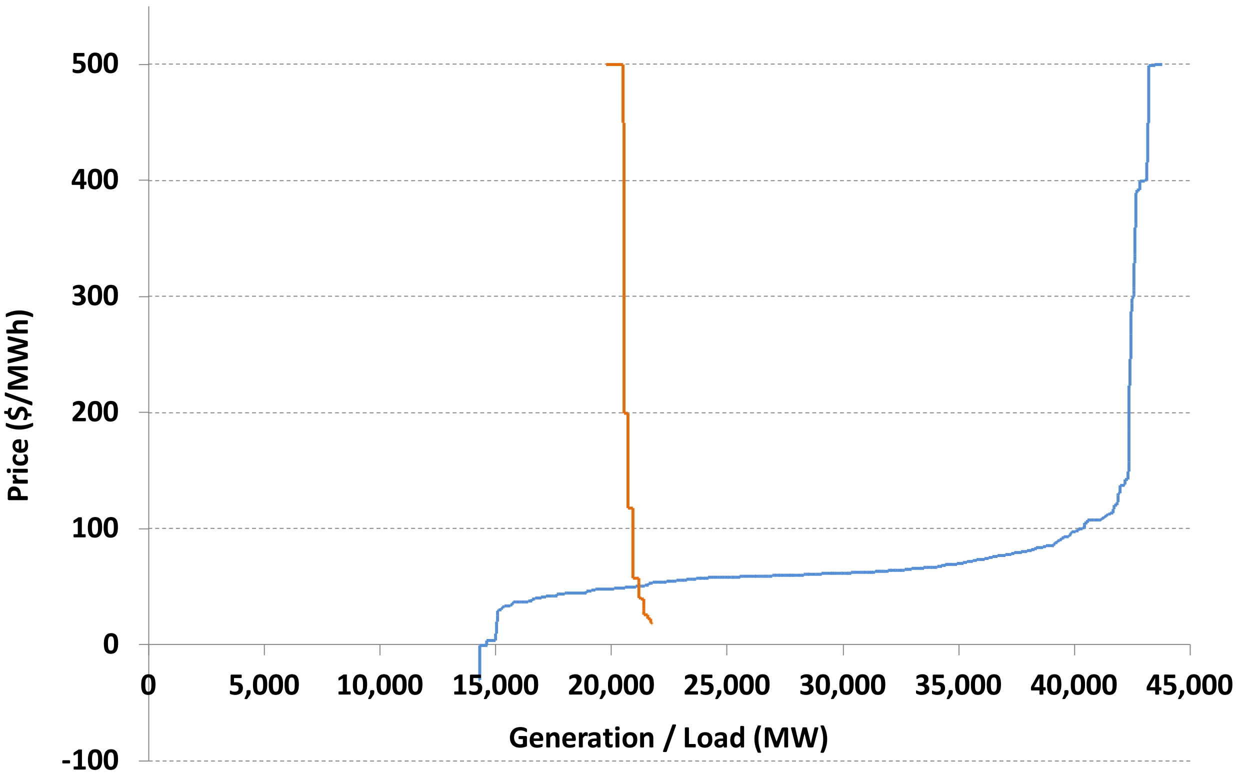

Figure 28. Supply and demand curve for hour 0 of December 17, 2009

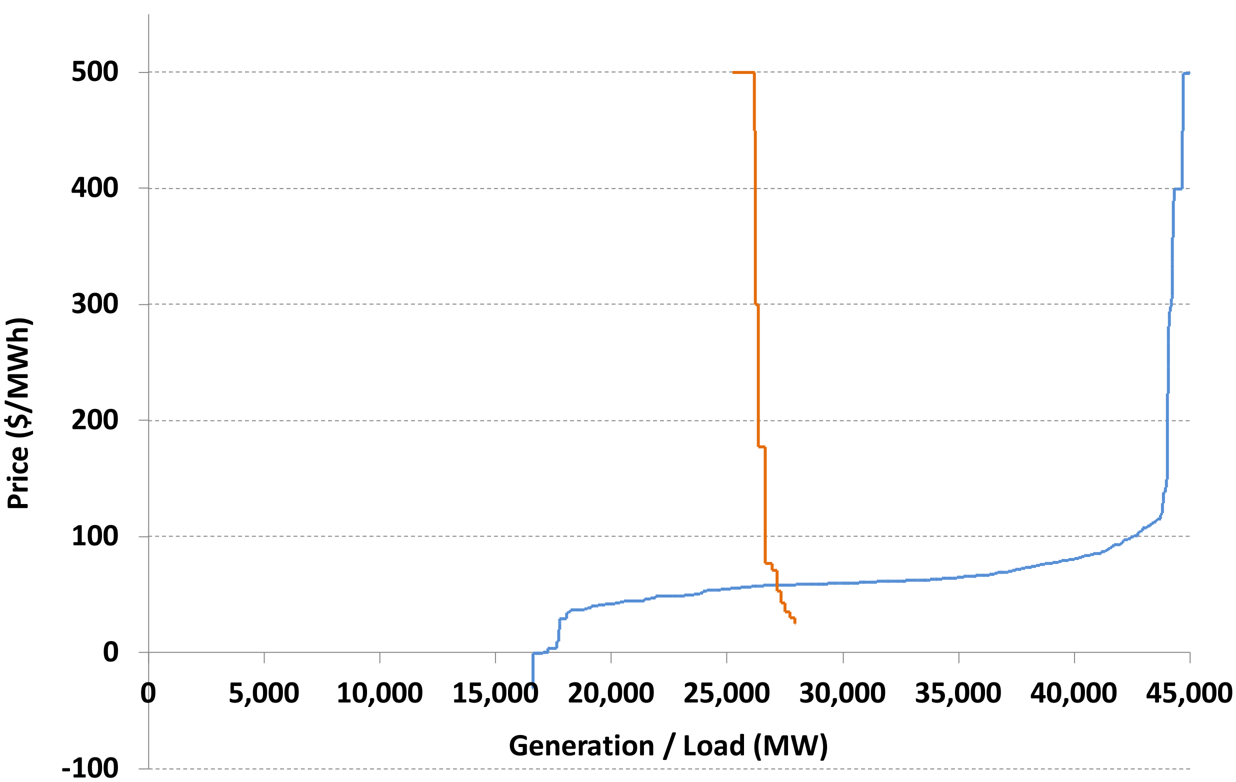

Figure 29. Supply and demand curve for hour 12 of December 17, 2009

The market-clearing price using the above described method results in prices that are less volatile than actual reported day-ahead market clearing price (from CAISO); on average, the absolute difference between calculated market clearing price and actual price is \$6.0/MWh and the average difference is \$3.6/MWh less than the actual price. This is most likely a result of the simplifications made here, as the operational and economic constraints not taken into account. For example, I do not take into account generators' start-up costs, minimum generation limits, ramp rate limits, and part-load inefficiencies, as well as ancillary service requirements, due to a lack of data. This results in less constraints and hence lower price volatility than from the algorithm used by the CAISO to generate prices, but this method still provides insights on general price trends.

3.4 Results

3.4.1 Wholesale price impacts of PV

By modeling the merit-order effect of PV generation on CAISO bids, I simulated the short-term, wholesale price impacts of PV generation. I modeled these price impacts for April 2009 through December 2010, using modeled PV generation and CAISO bid data from CAISO's OASIS web site, as described in section 3.2.

3.4.1.1 Reduction in electricity price with increasing PV penetration for two characteristic periods

As expected, PV generation reduces wholesale electricity prices, as per the merit-order effect. The hourly supply curve is shifted outwards by the amount of PV generation that hour, and for monotonically increasing supply curves, this leads to a lower wholesale electricity price that hour. As an example, Figures 30 and 33 show electricity prices without PV and with an increasing PV penetration, as well load and PV generation for the weeks of February 1-14, 2010, and August 1-14, 2010, respectively.

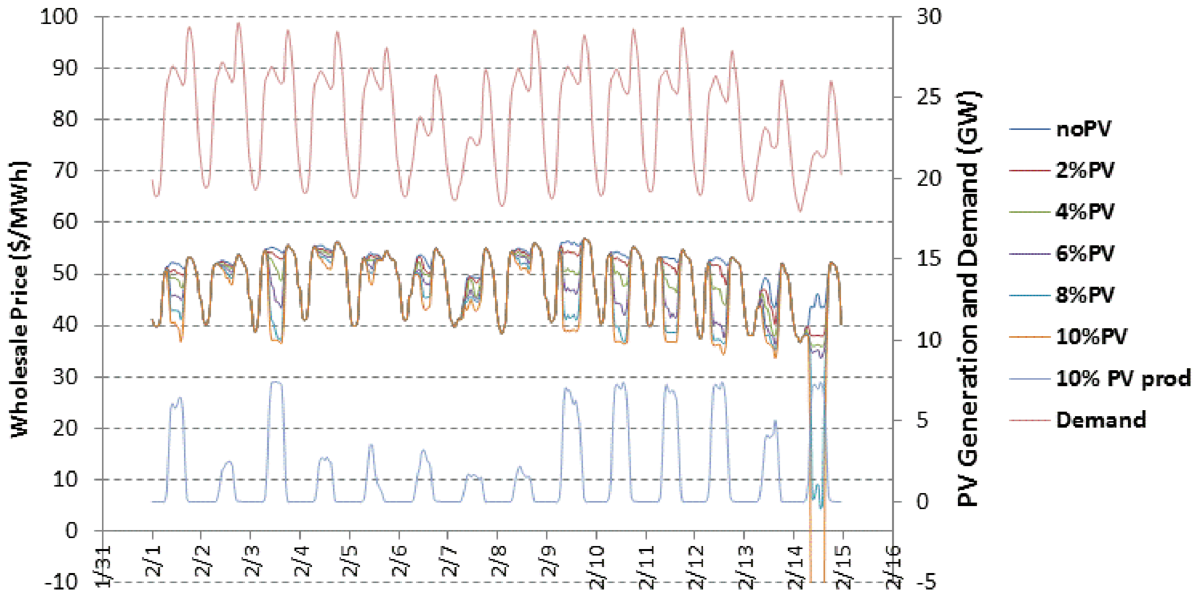

Figure 30. Price impact from simulated PV generation in CAISO area, for February 1-14, 2010.

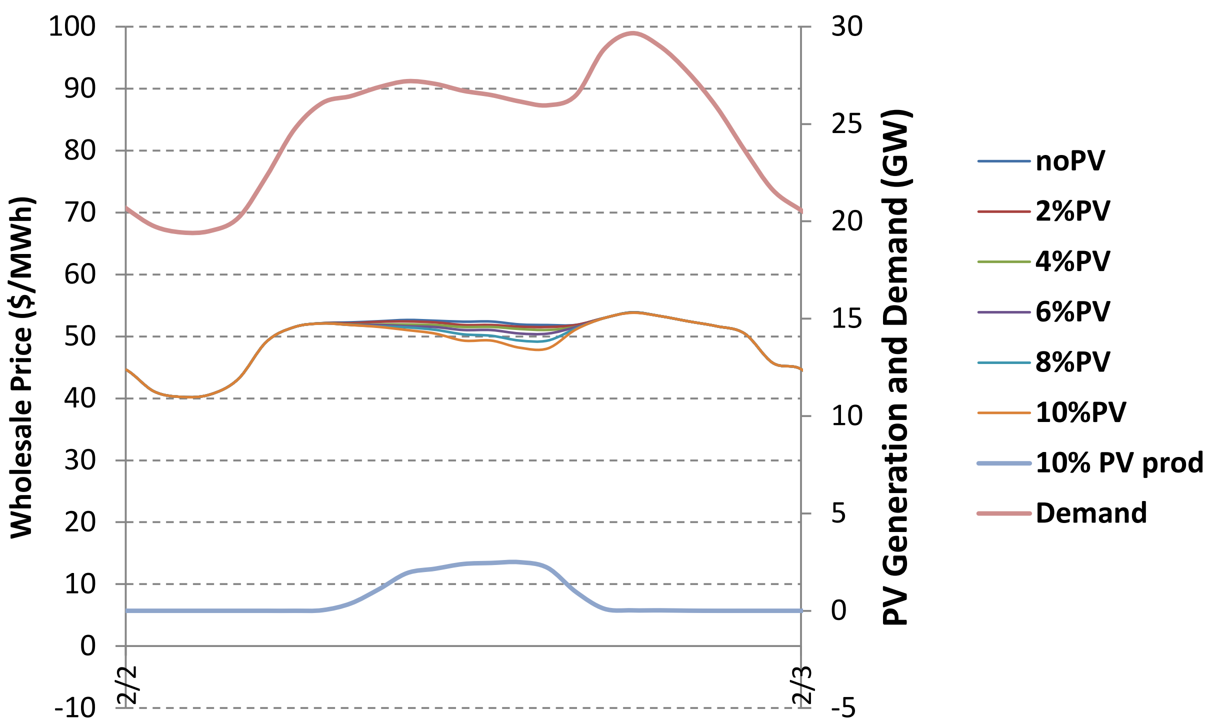

Figure 31. Price impact from simulated PV generation in CAISO area, for February 2, 2010 (cloudy, winter weekday).

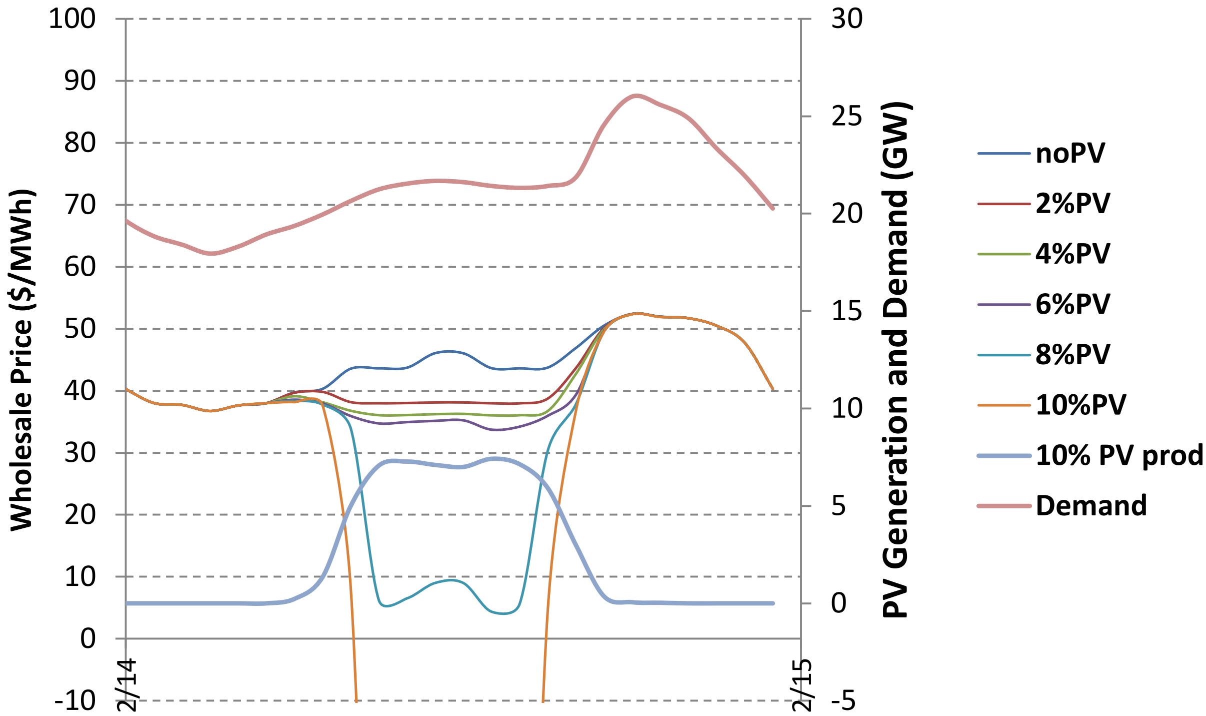

Figure 32. Price impact from simulated PV generation in CAISO area, for February 14, 2010 (sunny, winter weekend day).

The first two weeks of February represent typical winter load and solar profiles. The daily load profiles have two humps, a smaller peak in the morning (around 9-10 AM) followed by a trough in mid-day, and then a higher peak to around 30 GW around 6 pm, which is a typical evening-peaking load profile. The PV profiles are also characteristic of winter, with seven sunny days (on the 1st, 3rd, 9th, 10th, 11th, 12th, and 14th) with PV generation peaking around 7 GW for a 10% penetration level. The weekend loads (on the 6th, 7th, 13th, and 14th) have a similar shape to the weekday loads, but with lower load levels and peaks. With no additional PV penetration, price profile shapes resemble the load profile shape, rising to a morning peak at around 9 AM and again for a daily peak around 6 PM. As PV penetration increases, the prices between 9 AM and 6 PM fall to lower levels, depending on the PV generation that hour. On a cloudy weekday, such as February 2nd (see Figure 31), prices fall in mid-day from about $52/MWh to $49/MWh, a relatively small decrease in prices. On a sunny weekday, such as February 3rd, prices mid-day prices decline much more substantially, from about $55/MWh to $37/MWh at noon. On a cloudy weekend day, prices are more sensitive to PV generation, as the demand is generally lower and hence the demand curve intersects the supply curve further to the left, at a steeper section of the supply curve. The lower section of the supply curve is steep due to the minimum load requirements and inflexibility of baseload generators; inflexible generators cannot simply be turned off and hence bid less than their marginal cost in some hours, which explains the negative bids. The steep slope implies that small outward shifts in the supply curve will impact prices more than if the supply curve were flatter at the point of intersection with demand. On a sunny weekend day, such as February 14th (see Figure 32), even low PV penetrations have a high wholesale price impact. At 11 AM, the price drops from $46/MWh without PV to about $38/MWh with a 2% PV penetration. At a 10% PV penetration, prices are negative from 9 AM to 2 PM. These negative prices are much more likely to happen on weekend days because loads are generally lower then.

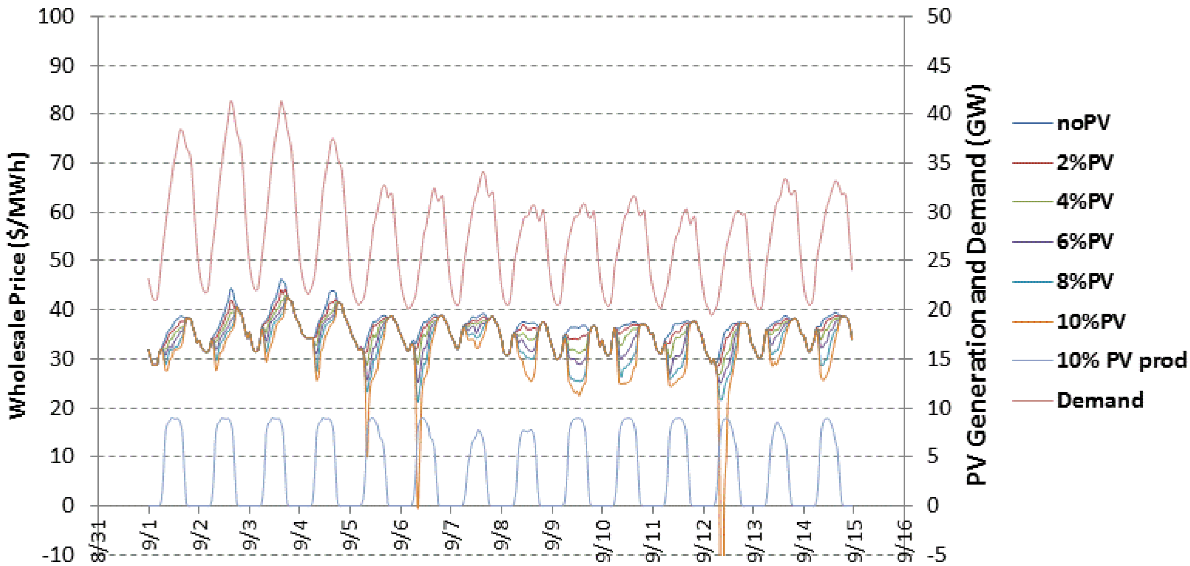

Figure 33. Price impact from simulated PV generation in CAISO area, for September 1-14, 2010.

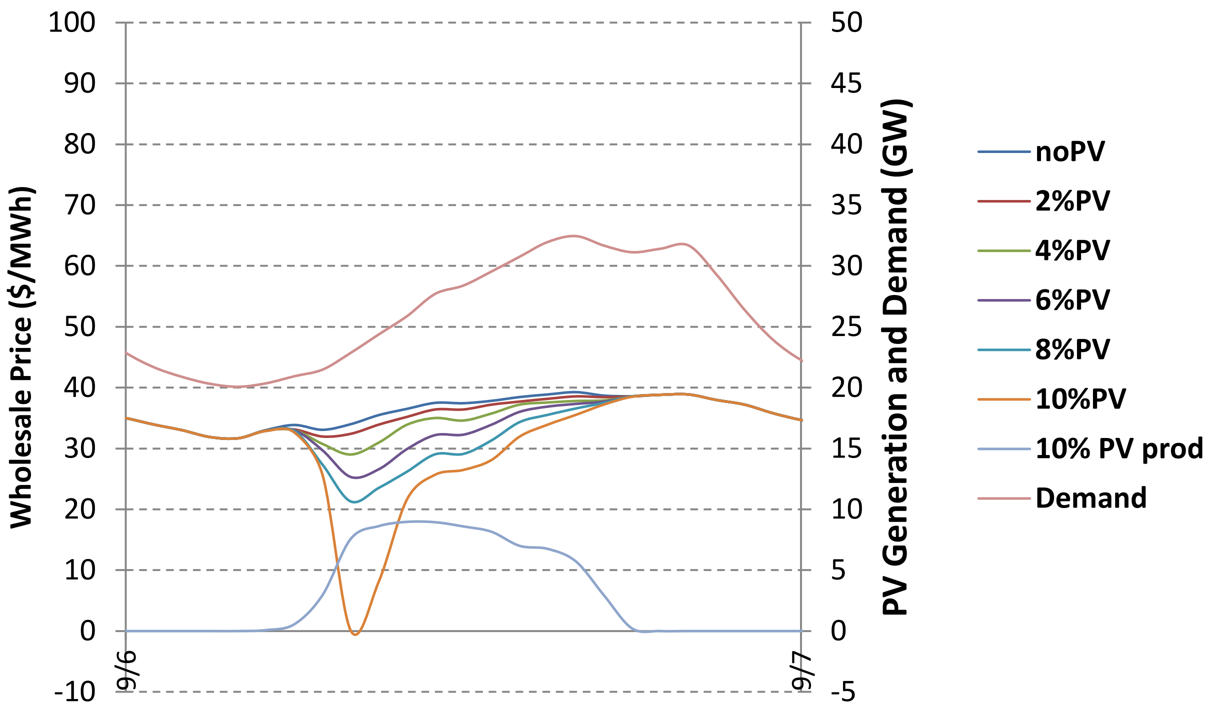

Figure 34. Price impact from simulated PV generation in CAISO area, for September 6, 2010 (sunny, summer weekend day).

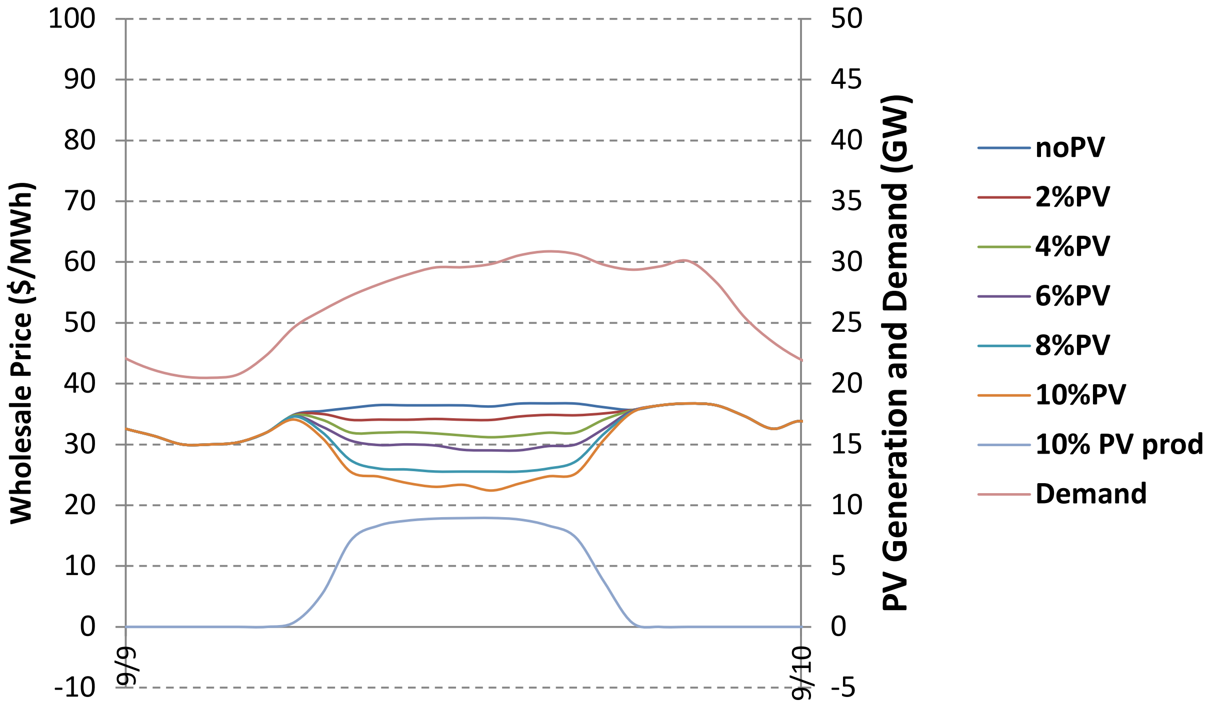

Figure 35. Price impact from simulated PV generation in CAISO area, for September 9, 2010 (sunny, summer weekday).

The first two weeks of September represent typical summer load and solar profiles, for California. The load profiles are quite different than for the winter days, as they peak at higher levels and different times. Instead of the morning and evening peak observed with the winter load profiles, summer daily load profiles rise continuously from morning until about 3 PM, at which point they peak at 30-40 GW (sometimes up to 45 GW). The load then sometimes rises at 5 PM before declining continuously until 1 AM. The weekend profiles are not as different to weekday profiles as during the winter months, because temperatures and air conditioning are the main drivers to peak loads in summer days. In the first two weeks of September, 2010, the average temperatures in CA were high for the first few days of the month, followed by more moderate temperatures (Weather Underground, 2012), which explains the higher price peaks from September 1st through the 4th. On high load peak days, such as September 3rd, simulated prices rise to $45/MWh[43] without PV. This peak price declines to about $38/MWh with a 10% PV generation. The relatively low price decline is due to the low steepness of the supply curve at the intersection of the demand curve. On the days with lower peaks, the erosion in the peak price is greater; on September 9th (see Figure 35), the peak price falls from about $37/MWh at 3 PM with no additional PV generation to $25/MWh with a 10% simulated PV penetration. On a few days, prices fall to even lower levels earlier in the day when PV generation is still ramping up, but load is still relatively low. For example, on September 6th (see Figure 34), at 8 AM when load is 22.9 GW (peaking later in the day at 32 GW), and PV generation is 7.6 GW, prices fall to

[43] Prices rise to higher level in reality, but as explained earlier, these simulated prices are less volatile than real prices as they do not take into consideration generators' start-up costs, minimum generation limits, ramp rate limits, and part-load inefficiencies, as well as ancillary service requirements.

almost zero for a single hour, before load ramps up faster than PV generation and prices climb back to $22/MWh at 10 AM.

3.4.2 PV Valuation for increasing PV penetration

As prices fall with increasing PV penetration in the hours PV generates, the average value of PV also declines. The average simulated PV valuation, over the entire year, is $39.8/MWh. This is 2% higher than the average price over the year – $38.9/MWh – due to the positive correlation between insolation and above average prices (i.e. a solar value factor of 1.02).[44] However, with increasing PV penetration rates, the economic value of the PV generation decreases, based on lower prices resulting from the higher PV levels. As seen in Figure 36 (blue diamonds), the decrease in value is almost linear through a 7% penetration[45], but accelerates from the 7% penetration to the 10% penetration level. This is related to the shape of the supply curve; at lower PV penetrations, the slope of the supply curve where demand intersects is shallow, and hence additional PV generation leads to a moderate decline in prices. As the supply curve is shifted outwards, the slope of the supply curve at the point of intersection with the load curve become steeper, leading to more significant decreases in price. Until about 7% PV penetration, the supply curve is shifted outwards so that the intersection with demand shifts along a weak slope, but at around 8% PV penetration, the intersection with demand starts being along a steeper slope.[46]

The other line in Figure 36 (red squares) shows the impact of a flat block of zero-marginal cost power on PV valuation. A flat block of power would also result in a decrease in prices during times PV generates, but the effect would be weaker since the flat block of power would generate less at times when PV output is strong than the equivalent penetration rate with PV. The decrease in value of PV generation is almost perfectly linear. This can be explained by the point of intersection between the supply curve and the demand curve which stays at a constant shallow slope even as the supply curve is shifted outwards.[47] The lower erosion in value of PV for a flat block of power shows that PV's generation profile shape is concentrated in hours where, without PV, prices are higher than average.

[44] Were real prices used, as reported by the CAISO in OASIS for the same time period, rather than simulated, the average PV valuation would be 8% higher than the average price over the year with zero added PV (i.e. a solar value factor of 1.08). The difference between the real and simulated PV valuation is due to the lower volatility of the simulated prices, for reasons described previously.

[45] The long linear section is a result of the shape of the CA supply curve, which as seen in Figure 29, has a long shallow slope in its middle section.

[46] This is due to California's current electricity market's overcapacity, a result of the electricity crisis in the early 2000s, and low demand growth in the recent past. In future years, when load catches up and there is less overcapacity, we would expect the linear part of the curve to be shorter, with PV valuation dropping off at even lower PV penetration.

[47] At a sufficiently high penetration, the flat-block of power would lead to a precipitous decline in the value of PV generation, also.

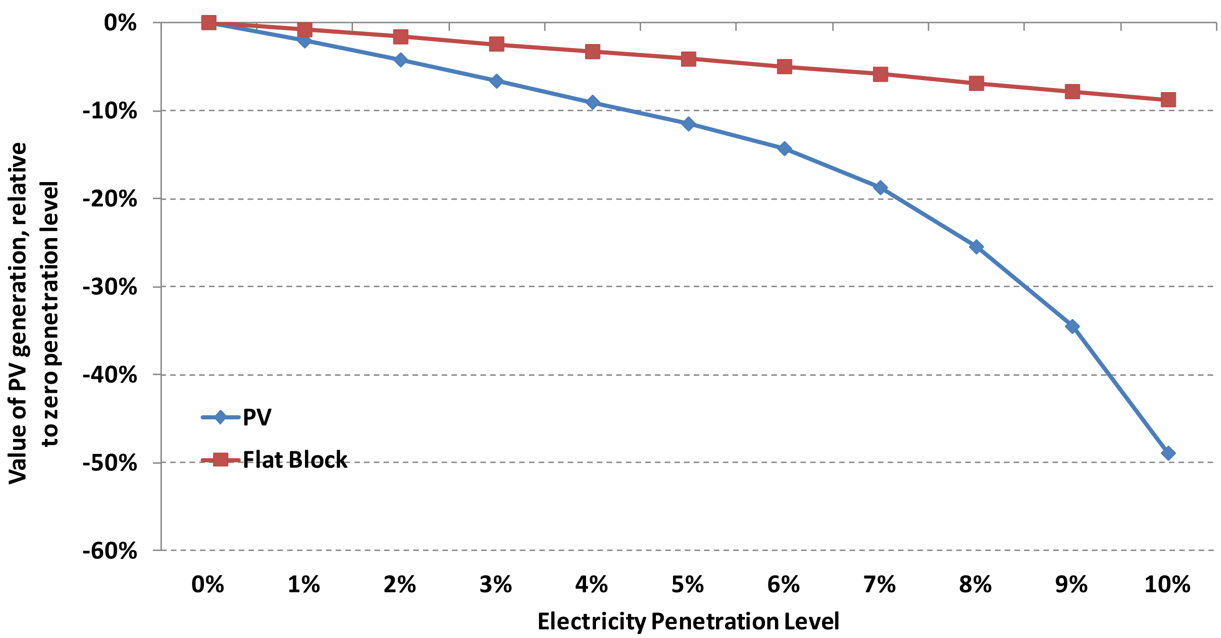

Figure 36. PV valuation with increasing PV penetration and penetration of a flat-block of zero-marginal cost power

3.5 Conclusions and limitations of the merit-order method

In this chapter, I have simulated the merit-order effect for PV penetration generation levels up to 10%. Using publicly available CAISO electricity bid data, I reconstructed supply and demand curves from individual hourly bids from generators and imports, and loads and exports, respectively. By intersecting the supply and demand curves, I computed the hourly market clearing prices for a test period of April 2009 through December 2010. Simulated prices were found to decrease when PV generates at rate greater than a zero marginal-cost flat block of power. At low PV penetrations, the erosion in the value of bill savings increased linearly, up to about 7% penetrations, followed by a faster rate of erosion through 10% PV penetration. For the simulated 10% PV penetration, the value of PV generation fell, by \$6.8/MWh on average (by 49%), relative to its value with no additional PV added to the system. This is 44% lower than the value of PV with a zero marginal cost flat block of power with a 10% penetration.

This method of calculating decrease in value with increasing PV penetration clearly shows how PV may erode its own value in the wholesale market, using basic economic reasoning relating to supply and demand. Though the method employed here is similar to a number of articles, such as Saènz et al and Sensfuß et al., there are a number of issues that limit its accuracy.

First, relating to the data used in this specific analysis, there is added imprecision in the results due to how imports and exports are reported. In the bid data provided by the CAISO (at the time of the analysis), import and export bids were not differentiated. Some of these bids could be used in the reconstruction of these curves, since monotonically increasing bids are always identified as imports and decreasing bids are always identified as exports. The rest of the bids were either self-scheduled bids, or single price bids (e.g. 100 MW at $30/MWh could be either an import or an export bid). The total amount of imported generation and exported load was known, however, so the difference between the total amount and that which cleared the market was added to the imports (or exports) as self-scheduled bids. This resulted in steeper demand and supply curves (due to more self-scheduled bids), which amplifies any price errors. In addition to these errors, I also found a small number of errors in the raw data, where the bid data was not properly structured (and hence the bid data was not used). Assuming that these data errors were random, and a similar number of bid data errors existed for supply and demand bids, the bid prices would not be affected much by the imperfect data quality.

More importantly, using the merit-order effect to understand how wholesale prices may change has a number of limitations, particularly when it is used to simulate price impacts of higher PV penetrations. The first is related to the capacity mix assumed. Although using actual bid data may better reflect actual bidding strategies than modeled supply and demand bids, using real bid data assumes that the generation capacity mix is static (Nicolosi, 2012). This assumption may be accurate when modeling short-term markets with small amounts of incremental PV. However, higher levels of PV penetration would lead to changes in the conventional capacity mix, in order to accommodate and adapt to the higher PV penetration market. Higher PV generation levels may encourage more combined cycle gas or combustion turbines in order to integrate the variable renewable generation, for example, and the retirement of inflexible baseload generators. Any change to the capacity mix would also result in a change in the supply curve. Also, the construction of sufficient PV to reach the modeled penetrations may take several years, and the load curves may also shift outward due to annual load growth, compared to the load curves used in this analysis. Finally, the electricity market used in this analysis is not in equilibrium, even without PV generation. The California electricity crisis of 2000-2001 lead to the over-construction of generation, and in combination with the great Recession, the market of 2009-2010 (the years used in the current analysis) is over-capacity. This has implications on the shape of the supply curve (i.e. the relatively large section of the curve with a shallow slope), and the simulated impact of PV generation on prices (which would decrease faster with increasing PV penetration than they do in the results presented in section 3.4). With time, as peak load grows, PV generation levels rise, and older power plants retire, investments in new generation to be added to the capacity mix will be required, and the choice of which generation to build will depend on the load profiles and PV generation levels.

Another important factor not taken into account when using the methodology in this chapter to simulate wholesale price impacts of PV generation is the operational constraints of conventional generation. PV generation is an intermittent source of power and there may be large swings in generation in relatively short periods of time, resulting in the need for generators to ramp up and down their electricity production quickly. Given that generators have start-up costs and ramping limits, this may change the bidding behavior of some generators, and additional generators may need to provide ancillary services in order to maintain high levels of adequacy and reliability. Clearly, the mechanism to choose which generator is turned on or off at a specific generation level is more complex than simply assuming the intersection of supply and demand as is the case with the current analysis.

These limitations highlight the need for a method that generates wholesale prices under higher PV penetration scenarios with the following characteristics:

- *An appropriate conventional generation mix*. Recognizing that significantly higher PV penetrations will require a different capacity mix than that which is online today, a model that takes into account plant retirement and investment would more accurately characterize future electricity market conditions.
- *Economic dispatch that takes into account operational constraints.* The dispatch of generation to meet demand each hour should take into account start-up times and ramp rate limits, which requires a more sophisticated methodology as well as more detailed inputs on each generation technology.
- *Hourly price resolution.* Given the variability of solar generation, it is crucial to simulate electricity prices on an hourly scale. Using type-days or daily averages would clearly fail to give the required detail to evaluate the value of solar PV.

Even after discussing the limitations of using the merit-order effect to evaluate wholesale electricity price changes with increases in PV penetration, and though this ultimately has led me to use a more accurate and complex model, developed by Mills and Wiser (2012), this preliminary analysis has allowed for a better understanding of the underlying dynamics of how wholesale market characteristics – in this case higher PV penetrations – can impact wholesale market prices.

Chapter 4 ELECTRICITY BILL SAVINGS FROM RESIDENTIAL PHOTOVOLTAIC SYSTEMS: SENSITIVITIES TO CHANGES IN FUTURE ELECTRICITY MARKET CONDITIONS

Customer-sited PV systems in the United States are often compensated at the customer's underlying retail electricity rate through net metering. Calculations of the customer economics of PV, meanwhile, often assume that retail rate structures and PV compensation mechanisms will not change and that retail electricity prices will increase (or remain constant) over time, thereby also increasing (or keeping constant) the value of bill savings from PV. In this chapter of my dissertation, I investigate the impact of, and interactions among, three key sources of uncertainty in the future value of bill savings from customer-sited, residential PV. These three sources of uncertainty are: changes to electricity market conditions that would affect retail electricity prices, changes to the types of retail rate structures available to residential customers with PV, and shifts away from standard net-metering toward other compensation mechanisms for residential PV.

I seek to explore the interactions between these three types of potential future changes. For example, higher penetrations of renewable energy could have a significant impact on the hourly profile of wholesale electricity prices. These changes could, in turn, impact retail electricity rates and the bill savings from residential PV, particularly if full net metering were no longer available or if residential retail rate structures were to shift towards marginal cost pricing with higher temporal resolution (i.e., prices that change with period of the day or hour) through TOU rates or RTP. Though a number of these topics have been treated separately in the published literature (to be discussed in the literature review section), this is the first known effort to evaluate these types of interactions. The assumptions are based on a California market in a future year (though the focus is not meant to be California-specific).

4.1 Introduction

4.1.1 Literature review and context

This dissertation chapter builds on a body of literature that has approached different aspects of net metering, rate design, and renewable electricity generation. Electricity markets of the future may look very different from today's, sometimes in unpredictable ways. For example, the amount of future renewable energy (RE) deployment is not known with certainty, nor are future natural gas prices or policies that might seek to limit carbon emissions. Such changes could influence both the cost of electricity supply and the hourly profile of wholesale electricity prices. These changes, in turn, will impact average retail electricity rates and the temporal profile of time-differentiated rates and thus the customer economics of behind-the-meter solar (Figure 37). Despite this, there have been few attempts to explore the impact of future electricity market changes on *both* average retail rates *and* the temporal profile of rates that are time differentiated (TOU and RTP). One example is Parmesano and Kury (2010), which investigates the potential impacts of carbon policies on retail electricity rates, but I am not aware of any studies that explore these issues as they relate to solar energy.

A number of studies have, however, examined the impacts of renewable generation on hourly wholesale market price profiles. Many of these analyses have only considered the short-run wholesale price impacts of increased RE, either using existing case studies (e.g., Jacobsen and Zvingilaite, 2010; Woo et al., 2011; Weiss et al., 2012) or short-run modeling frameworks that consider the so-called "merit-order" effect (e.g., Chapter 3, Sáenz de Miera et al., 2008; Sensfuß et al., 2008; Green and Vasilakos, 2010). In the long run, however, changes in investment decisions with increasing deployment of RE can impact wholesale power prices (Steggals et al., 2011). Models that simultaneously consider economic investment and dispatch can be used to minimize generation costs or generate wholesale prices that represent markets in long-run equilibrium for scenarios with increased renewable penetrations (Lamont, 2008b; De Jonghe et al., 2012; Mills and Wiser, 2012). The investment, capacity-expansion, and dispatch model developed and described by Mills and Wiser (2012) is used in this study (see section 4.2.3).

In order to understand the implications of changes in electricity markets on the customer economics of residential solar, it is necessary to study the links between those changes and retail rates: not only the average level of retail rates, but also the temporal profile of rate structures that include time-varying pricing. This is because PV generation likely will continue to be compensated, at least in part, at the customer's underlying retail rate and because a variety of future retail rate structures are possible. As emphasized in Bonbright's seminal work, utility rates and rate structures are influenced by a variety of social and economic goals (Bonbright, 1961). One of those goals is maximizing the economic efficiency of rate structures, and, in recent years, there have been renewed efforts to move customers to time-varying rates to provide more accurate price signals to which customers might respond (Borenstein, 2005b; Faruqui and Sergici, 2010). This has included the introduction of TOU rates, which set various prices for different periods based on historical cost of service, and RTP, which allows prices to change on an hourly basis depending on the market conditions and prices each hour. Although these rate structures have, to this point, been more common for larger, non-residential customers, and in limited residential pilot programs, their widespread introduction for residential customers (facilitated by smart meter deployment) has begun (FERC, 2011). Because changes in electricity markets may lead to temporal shifts in wholesale price profiles, the level and design of TOU and RTP rates may also vary depending on future electricity market conditions.

Another critical consideration for the relationship between retail rate structures and the economics of PV is whether net metering will continue to be the prevailing means of compensating behind-the-meter PV generation. In the past few years, some utilities have challenged traditional net metering. San Diego Gas and Electric (SDG&E) in California and Xcel in Colorado, for example, have both sought (without success, so far) to charge solar customers for their use of the distribution network.[48] Austin Energy, meanwhile, has created a residential solar rate—based on an estimate of the value of PV-generated electricity—that replaces the net-metering arrangement (Rábago et al., 2012). Barnes and Varnando (2010) and Darghouth et al. (2011) consider the implications of moving away from net metering to alternative compensation mechanisms for PV.

Prior studies have also explored the linkages between *current* retail rate levels and rate structures and the customer economics of behind-the-meter PV, represented by the second arrow

[48] Under a number of net-metering rules, customers can theoretically displace 100% of their electricity bills. Some argue that these customers should still pay a fee to utilities to cover the cost of service related to billing and distribution networks.

from the bottom in Figure 37. Darghouth et al. (2011), for example, quantify the value of bill savings for residential PV using then-current retail electricity rates with net metering. In a study of the cost effectiveness of net metering conducted by E3 (2010a), the total costs and benefits of net metering to the utility and its ratepayers are evaluated. Borenstein (2007) investigates the customer economics of net-metered residential PV systems to determine whether mandatory TOU rates for PV customers would reduce bill savings. Mills et al. (2008) investigate the impact of retail rate structures on the value of bill savings for commercial customers in California, focusing in part on the extent to which PV can reduce customer demand charges. Ong et al. (2010) also investigate the role of commercial retail rate structures on the customer economics of PV. A number of studies, including Hoff and Margolis (2004), Borenstein (2005a), Borenstein (2008), and Bright Power Inc. et al. (2009), show that PV customers can often benefit from time-varying retail rates over flat rates.

In summary, a considerable literature exists on related topics. However, that literature has not considered retail rate design and net metering concurrently with potential changes in wholesale price profiles associated with future electricity market scenarios. The present research seeks to fill that gap.

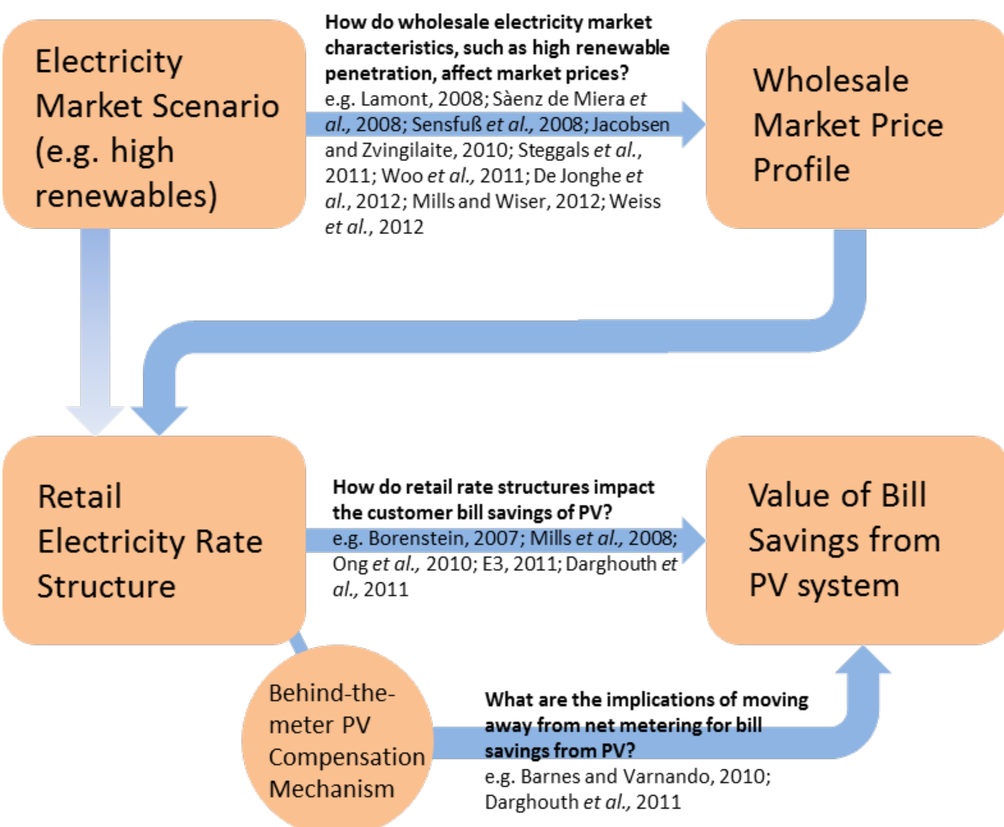

Figure 37: Mapping the Existing Literature

In this chapter of the dissertation, I consider a variety of residential retail rate structures, though for the results to be tractable, a few common assumptions were made. The approach I take is to design rates that are at neither extreme of the efficiency spectrum. One end of the spectrum would be a two-part tariff that recovers both energy and capacity costs with a time-varying volumetric component, in addition to a single customer charge for all customers to recover the utilities' fixed costs. The customer's marginal rate at any point in time would be exactly equal to the marginal cost of generating and delivering electricity to the customer, allowing the customer to respond appropriately to price signals and minimize any inefficiency (i.e. avoid deadweight loss). Near the other end of the spectrum would be rates that resemble today's rates in California: rates which cover all energy and fixed costs through an increasing block pricing rate and where capacity costs are spread equally through all consumption. In this case, the cost of generating and delivering electricity to the customer is completely opaque to them; the price signals sent to the customer are not related to the actual costs, leading to inefficient allocation of resources (i.e. deadweight loss). Though I do implement each of these rates as side analyses, my central analyses include rates closer to the middle of the spectrum. My central analyses assumes that rates do not include increasing block pricing, capacity costs are recovered through rates in peak hours, but fixed costs are still recovered through constant volumetric charges. This serves as an intermediate between an economically efficient rate that is hard to implement because of political considerations and one that is seriously flawed with regards to economic efficiency. Details of the rates considered will be presented in section 4.2.4.

4.1.2 Basic approach, limitations, and boundaries

The principal objective of this study is to characterize the sensitivity of the value of bill savings from behind-the-meter PV to changes in electricity market conditions and the dependence of those sensitivities on retail rate structures and PV compensation mechanisms. To understand these sensitivities and interactions, I take the following approach (which is detailed further in section 4.2). First, I model the impacts of various electricity market scenarios on hourly wholesale market prices, using a simplified production-cost and capacity-expansion model developed by and extensively described in Mills and Wiser (Mills and Wiser, 2012). I base a subset of the assumptions on projections for what the California electricity market may look like in 2030. Second, based on the hourly wholesale market prices calculated in the first step, and with other assumptions specified later, I create three potential future retail rates for each electricity market scenario: a flat rate, a TOU rate, and an RTP rate. The rate levels and structures are—in each case—created by assuming full utility cost recovery, using standard rate design principles. Third, for each of 226 California residential customers for whom data on hourly metered load are available, I determine the value of bill savings from PV by calculating those customers' annual electricity bills with and without PV generation, for each retail rate type and electricity market scenario. I calculate bills with PV for each of the three rates considered (flat, TOU, RTP) using two PV-compensation methods: (a) net metering, whereby PV generation is credited at the prevailing retail rate at the time the generation occurs, and (b) hourly netting, whereby PV generation can displace the customer's load within each hour, but any PV generation in excess of customer load within the hour is compensated at the prevailing wholesale electricity market price.[49]

[49] The rationale for using hourly netting as an alternative to standard net metering is described further in Section 2.

As in any study of this type, the results are, to some extent, driven by the underlying assumptions, and the conclusions are limited by the scope and structure of the analysis. Several key assumptions and limitations are particularly worth noting up-front, many of which are discussed more fully within the conclusions, in section 4.5. First, I focus on the private value of bill savings for the residential PV system owner and do not seek to quantify the broader social cost or value of solar electricity, nor do I seek to quantify the value to the system.[50] Second, the analysis is based on electricity market characteristics that are, in part, loosely based on California's electricity market as it might be in 2030, but is not intended to be a forecast of California's electricity market. At the same time, although the general results of the analysis are intended to have applicability beyond California, the findings in some cases are closely linked to the particular electricity market characteristics assumed. Third, in my central analysis, I use an economic investment and dispatch model developed in Mills and Wiser (2012) that simulates an energy-only market with no parallel capacity markets. Under this kind of market design, hourly electricity prices can climb to very high levels for a small number of hours during the year. The results of the analysis may be heavily impacted by the prices within those few hours, and some of the findings could differ significantly under other wholesale market designs (e.g., an energy market with a price cap, combined with a parallel capacity market), one of which I explore in one of the side analyses, described in section 4.2.5. Next, I consider California as a single isolated region, whereas it is (and is likely to increasingly be) interconnected within the Western Electricity Coordinating Council (WECC) and hence the wholesale market conditions for the entire WECC region could be considered. However, some wholesale electricity market conditions such as renewable penetration are likely to be similar in neighboring states and hence roughly equivalent modeling results may be applicable (see section 3.1.3 for a more thorough discussion on this topic). Finally, in order to maintain a tractable number of comparisons, the analysis examines a limited set of possible electricity market scenarios, retail rate designs, PV compensation mechanisms, and PV array orientations. It goes without saying that other assumptions for each of these elements are possible and may be warranted for further exploration in follow-up analysis. For example, additional analysis could be warranted to examine the impact of residential retail rate structures with large fixed customer charges or a move from net metering to feed-in tariffs (FIT) for customer-sited PV, as a number of states and utilities are considering larger fixed charges or value-of-solar FITs.

4.1.3 Chapter Outline

Section 4.2 discusses the study's data and methods. Section 4.2.1 introduces the electricity market scenarios considered in this study. The reference scenario is based, in part, on current renewable generation in California. I modify single elements from the reference scenario in the Isolation scenarios to study their impacts on retail rates and value of bill savings from PV. A 33% renewable penetration scenario is introduced as well as three variations on this scenario. The energy-only market design in the central analysis is discussed in section 4.2.2. This discussion is followed in section 4.2.3 by a description of the model used to simulate wholesale electricity prices in the scenarios. Section 4.2.4 outlines the methodology used for designing the retail rates; section 4.2.5 introduces the methodology for the alternative market design and rate

[50] For example, behind-the-meter PV may lead to avoided transmission and distribution costs and losses. Refer to E3 (2010a), Barnes and Varnando (2010), and Weissman and Johnson (2012), for example, for a more comprehensive description of potential social benefits of net metering.

structures considered; Section 4.2.6 describes and characterizes the customer load data and PV-generation data used in the study, and Section 4.2.7 details methods used to simulate customer electricity bills and calculate the value of PV-derived bill savings. Section 4.3 presents the core results of the central analysis. Section 4.3.1 presents the results of the reference scenario, focusing on the impact of that scenario on retail electricity rates and the corresponding value of bill savings from PV for customers in the sample. Section 4.3.2 compares the value of bill savings from the isolation scenarios to those from the reference scenario for each rate and compensation mechanism. Section 4.3.3 presents the effect of increasing PV penetration on value from bill savings from PV. Section 4.3.4 presents results from the 33% renewable penetration scenario, focusing on the impact of this scenario on retail rates and the value of bill savings from residential PV. Section 4.3.5 summarizes results for three variations on the 33% renewable penetration scenario, each intended to mitigate potential declines in the value of bill savings. Section 4.3.6 summarizes the core results of the central analyses. Section 4.4 presents the results of the side analyses, with the alternative rates and market design considered. Section 4.5 provides conclusions, and discusses the limitations of the analysis and their implications both for the results of this study and for potential future research. The Appendices include tables with (A) the retail rates for each of the rate options and scenarios, (B) residential load and PV generation, as distributed within each TOU period and wholesale price bin, and (C) the value of bill savings from PV under each rate option and electricity market scenario combination.

4.2 Data, Methods, and Assumptions

4.2.1 Electricity market scenarios

The analysis presented in this chapter considers a range of electricity market scenarios for a future year (chosen to be 2030).[51] For all scenarios, California gross retail load is assumed to grow at an average of 1.2%/year through 2030,[52] to 340,975 GWh/yr, prior to deducting behind-the-meter generation, but retains a similar hourly load profile shape. Residential load is assumed to account for 32% of total retail load—the average for 2007 through 2010 (CEC, 2012). All scenarios assume the same capacity of legacy generation (i.e., generation plants that exist in 2010 but have not reached their technical lifetimes by 2030[53]), which is complemented by new generation that will need to be built to meet load and reserve requirements (this can differ for each scenario and is determined by the long-term capacity investment model described in Section 4.2.3). Distributed, behind-the-meter PV generation is assumed to be evenly distributed between residential and commercial sites for all scenarios.

The scenarios are summarized in Table 7. In the reference scenario, the renewable capacity is based on California's 2011 renewable electricity capacity and remains constant through 2030. Renewable energy generation serves 11.7% of annual total retail load in 2030, a lower

[51] The year 2030 was chosen as a date sufficiently far in the future that we may see such high penetrations of renewables and markets have time to adapt to such changes and reach equilibrium. The exact choice of date should not impact my conclusions significantly.
[52] As per California Public Utilities Commission projections through 2020 from 2010 levels (CPUC, 2010).
[53] This study uses the same assumptions for technical lifetimes as those used in Mills and Wiser (2012): 60 years for nuclear plants; 50 years for coal, natural gas steam, and geothermal plants; and 30 years for combustion turbine and combined cycle gas turbine plants. The technical lifetimes are based on an analysis of historical plant retirement ages or length of licenses. See Mills and Wiser (2012), footnote 29, for more details.

percentage than in 2011 due to growth in retail load. Specifically, 4.0% of load is met by wind generation, 3.7% by geothermal, 1.7% by biomass, 1.5% by small hydro, and 0.3% by PV. The price of natural gas is assumed to be $6.40/MMbtu,[54] from the U.S. Energy Information Administration's (EIA) reference projection (US EIA, 2011), and it is assumed that the price for carbon remains zero, for the reference scenario. Half of the PV electricity generation is assumed to be behind-the-meter, and half is assumed to be utility scale. The reference scenario assumes a very low elasticity of demand for all retail electricity consumers in the day-ahead market (E = -0.001). It also assumes the 2011 levels of pumped hydro storage (3.6 GW), which has a reservoir capacity of 10 hours and an efficiency of 90% for both the storage and generation of electricity (implying an 81% total efficiency). The reference scenario is not intended to represent the "most likely" scenario but rather serves as a baseline against which the other scenarios are compared.

All isolation scenarios are based on the reference scenario. These have been designed to investigate the retail rate impacts of changing a single characteristic in the wholesale market. In the high-PV scenario, sufficient utility-scale and behind-the-meter PV generation is added to meet 15% of total retail annual load, with no other changes to renewable generation (resulting in a total renewable penetration of 26%). Similarly, in the high-wind scenario, I add wind generation such that total wind generation is equal to 15% of total annual load (resulting in a total renewable penetration of 23%). The three additional isolation scenarios model a $50/ton carbon price, a high natural gas price ($7.97/Mbtu), and a low natural gas price ($4.95/Mbtu), with the natural gas prices based on EIA projections.[55]

Table 7: Electricity market scenarios

		2030 Renewable Penetration (energy)				Behind-the-meter PV	Natural gas	Pumped Storage	C Price	Elasticity of load
	Scenario name	**PV**	**Wind**	**CSP w/ storage**	**Other RE**	**% of Total PV**	**Price ($/MMbtu)**	**GW**	**$/ton**	
	Reference	0.3%	4.0%	0.0%	7.4%	50%	6.40	3.6	0	-0.001
Isolation scenarios	High PV	15.0%	4.0%	0.0%	7.4%	30%	6.40	3.6	0	-0.001
Isolation scenarios	High wind	0.3%	15.0%	0.0%	7.4%	50%	6.40	3.6	0	-0.001
Isolation scenarios	High C price	0.3%	4.0%	0.0%	7.4%	50%	6.40	3.6	50	-0.001
Isolation scenarios	High NG price	0.3%	4.0%	0.0%	7.4%	50%	7.97	3.6	0	-0.001
Isolation scenarios	Low NG price	0.3%	4.0%	0.0%	7.4%	50%	4.95	3.6	0	-0.001
	33% RE Mix	8.1%	11.5%	3.5%	10.0%	30%	6.40	3.6	0	-0.001
integr ation scena	High storage	8.1%	11.5%	3.5%	10.0%	30%	6.40	9.9	0	-0.001

[54] In 2011 $US, as with all currency numbers reported in this document.

[55] The prices from the low and high natural gas price scenarios are outputs from the from EIA's 2011 high and low shale gas cases, respectively (US EIA, 2011). The 2012 EIA Annual Energy Outlook's reference case has a natural gas price of $6.49/MMBtu (US EIA, 2012a).

	DR	8.1%	11.5%	3.5%	10.0%	30%	6.40	3.6	0	-0.1
	Increased CSP / decreased PV	3.5%	11.5%	8.1%	10.0%	30%	6.40	3.6	0	-0.001

Notes*: C = carbon; NG = natural gas; RE = renewable energy; DR = demand response.*

The other scenarios are based on the 33% RE mix scenario. These scenarios investigate how individual characteristics in the wholesale electricity market impact retail rates and the economics of PV in conjunction with a mix of RE in the system, arguably more likely given historical developments and electricity-generation projections (particularly given the renewable portfolio standards [RPS] in California and other states). For the 33% RE mix scenario, biomass, geothermal, and small hydro electricity generation meet 10% of total annual retail load, and the remaining 23% of load met by renewables is from a combination of wind (50%), PV (35%), and concentrating solar power (CSP, 15%). The CSP has a 6-hour storage capacity.

Three variations to the core 33% RE mix scenario reflect resources that could be added to the grid to integrate high levels of RE. Other analyses have highlighted the potential value of storage and demand response for integrating large amounts of renewables into the grid (Denholm et al., 2010; Roscoe and Ault, 2010; Cappers et al., 2011; Schwartz et al., 2012). In this study, the three scenarios reflect potential electricity market conditions that could mitigate a decline in the value of bill savings from behind-the-meter solar due to the 33% RE penetration scenario; henceforth, these scenarios are called “integration scenarios.” The first is the high-storage scenario, in which the capacity of pumped hydro is increased from its 2011 level of 3.6 GW to 9.9 GW—the total capacity of existing and proposed pumped hydro in California, as of 2011 (NHA, 2010). The demand response scenario is modeled simply by setting the elasticity of demand to -0.1 for the total and residential load and setting the average wholesale price as the base pivot point.[56] The final integration scenario holds total solar generation (PV and CSP) constant, but CSP generation increases to 35% of wind and solar generation (and PV drops to 15%).

The renewable generation site selection assumes a geographic diversity in and out of state for wind and solar generation sites, using results from Mills et al. (2010) and CAISO (2010). The wind generation profiles used in the scenarios are aggregate generation from a variety of Western Renewable Energy Zone (WREZ) sites that were selected based on their economic ranking (considering bus-bar cost of generation, transmission costs, and an estimate of the value of that electricity). Using this method, scenarios with low wind penetration included sites in California only, whereas those with 11.5% and 15% wind penetrations resulted in the additional selection of sites in other western states. The generation profiles for the wind sites selected are for the year 2004 (to match the hourly load shapes used) and based on the assumptions from the Western Wind and Solar Integration Study (Potter et al., 2008).

For PV site selection, I did not use results from the WREZ model because it only considers remote, utility-scale solar resources, whereas a portion of the solar generation in the present study is from behind-the-meter generation. Instead, I used sites identified by the California

[56] I assume that the majority of customers were under a flat rate in 2004 (the year that corresponds to the assumed load profiles), and hence load adjustments each hour are based on the difference between the wholesale price and the average wholesale price from 2004. I recognize that this is a simplistic approach to modeling demand response.

Independent System Operator (CAISO) renewable integration model for a 33% RPS scenario—18 distributed generation sites in urban areas and eight utility-scale PV sites in California (CAISO, 2010). I used the National Renewable Energy Laboratory's (NREL) System Advisor Model (SAM) to simulate PV generation profiles for each solar site. As input to SAM, I merged 2004 solar irradiance data from Clean Power Research's Solar Anywhere database (Clean Power Research, 2012), weather data from the National Oceanic and Atmospheric Administration's National Climatic Data Center (NOAA, 2012), and NREL's Typical Meteorological Year (TMY3) data files for each solar site (Wilcox and Marion, 2008). The utility-scale PV solar was simulated as half single-axis tracking and half fixed installations, both at a tilt angle equal to the installation's latitude. All distributed generation was simulated as fixed PV installations, south facing at a 25º tilt angle[57]. The utility-scale and distributed solar generation were scaled as necessary for each electricity market scenario and aggregated to form a single annual PV generation profile. A similar approach was used to simulate utility-scale CSP, although CSP generation is complemented by the assumed 6 hours of thermal storage.

4.2.2 Wholesale market design

Under an energy-only market design, as assumed in the central analysis, hourly wholesale electricity prices may rise above the marginal variable cost of generation during some hours of the years ("scarcity pricing"), allowing peaker plants that operate for very few hours and on the margin to recover their fixed costs directly through wholesale prices. Prices may climb as high as the value of lost load, at which point it is more efficient to shed load than to build additional capacity and allow higher prices. Alternatively, many wholesale market designs feature an energy market with a lower price cap, in combination with a separate capacity market that provides additional revenues to generators sufficient to cover their fixed costs and thereby ensure resource adequacy. If prices in the energy market were capped without any separate payments to generators, then peaker plants would not receive sufficient income to cover their upfront capital costs and would not be built, leading to uneconomic lost load. More detailed reviews of the energy-only model and capacity markets can be found in Stoft (2002), CPUC (2004), Wen et al. (2004), Oren (2005), Joscow (2008),and Newell et al. (2012).

Within the context of the present study, the choice of wholesale market design has implications for the structure of the retail rates developed in later phases of the analysis, and therefore could also impact the study's results on the bill savings from PV. Under an energy-only market design, the fixed cost of peaker plants required to ensure resource adequacy (i.e., "capacity costs") are reflected in wholesale electricity prices and, in turn, passed through to retail rates. Under a flat rate, total annual capacity costs are simply rolled into the flat volumetric charge applicable in all hours of the year. Under TOU and RTP rates, capacity costs are, instead, recovered within the TOU periods or hours in which scarcity pricing occurs, increasing the prices during those periods/hours (see section 4.2.4). When distributed PV is compensated at TOU or RTP rates, or excess PV generation at wholesale prices, the correlation between PV generation and these high priced periods can have a significant impact on the estimated bill savings from PV.

[57] In reality, however, distributed PV arrays may be oriented with any number of directions and tilts. However, the fixed orientation assumption is unlikely to create much error in the overall results (for more implications, see Section 4.2.6.2 and conclusions in Section 4.5).

Thus, as a side analysis, I also consider the impact of PV on bill savings under an electricity market design with price caps and a separate capacity market, for which the implementation details and results are discussed in more details section 4.2.5.1 and 4.4.1, respectively, as well as in the conclusions (section 4.5).

4.2.3 Wholesale prices

Wholesale price profiles for 2030 are modeled for each electricity market scenario using an economic investment and dispatch model, developed by and extensively described in Mills and Wiser (2012). Renewable resource capacity additions are fixed, per the scenario definitions described in the previous section, as is legacy generation that has not retired as of 2030. The model then co-optimizes conventional generation additions for energy and ancillary services, incorporating operational constraints and hourly time resolution, to determine long-term economic generation investments and resulting hourly wholesale market prices. Hourly load and renewable generation, as well as the existing generation capacity, are fixed as inputs to the model; near-zero elasticity is assumed for loads in all but one scenario, the demand response scenario. Given load growth and the fact that some existing generation will retire (having reached the end of its technical lifetime), new generation will need to be built to maintain adequate balance between supply and demand. The model chooses which types of generation are built and assumes economic equilibrium; that is, the amount of new conventional generation built is such that the short-run profit of any new generation is equal to its annualized fixed cost. In most hours, wholesale prices are set to the marginal costs of the most expensive generation needed to meet total hourly load. However, the wholesale market modeled is an energy-only market design, and hence, during peak-load hours, wholesale prices can increase to levels above the marginal costs of the most expensive generation. During these periods, all plants that are generating are assumed to earn high scarcity prices, up to $10,000/MWh (an estimate for the value of lost load[58]; see Table B-6 in Appendix B for table containing the wholesale price distribution). The resulting wholesale prices allow new conventional generation to recover exactly its fixed costs.

4.2.4 Determining residential retail rates from wholesale prices

In this section, I describe the methodology used to develop retail electricity rates in the principal and the side analyses.

4.2.4.1 Cost components of the electricity retail rate

Retail electricity rates are designed so utilities recover their costs plus a fair rate of return. The utilities' costs can be categorized as fixed and variable. Fixed costs are independent of short-term variability in demand, including capital expenditures in the transmission and distribution (T&D) network. Power purchase agreements with renewable power plants, requiring utilities to purchase the generator's output at all times at a predetermined price, are independent of short-term changes in electricity load. Variable costs change with the amount of electricity provided; in a partially deregulated market, the cost of electricity purchased in a wholesale market is a variable cost for utilities. Historically, most U.S. utilities have set residential retail electricity

---

[58] This is the same value of lost load as assumed in Mills and Wiser (2012), which is within the large range of values commonly cited, including Stoft (2002).

rates to recover most of the fixed and variable costs through a variable charge, with small or no fixed charges. While certain utilities have in recent years proposed increased fixed charges, in part a reaction to increasing behind-the-meter PV, I do not include this rate option in the central analysis presented in this chapter. Instead, for the central analysis, I have chosen to focus on flat, TOU, and RTP rates that recover all costs through volumetric charges. As one of a side analyses, I consider the impact of fixed charges on the economics of customer sited PV in section 4.2.5, and discuss implications of the results in the conclusions (section 4.5).

Each of the rates modeled assumes full cost recovery. Costs recovered through retail rates include operation costs of utility-owned generation, RE electricity purchases, T&D infrastructure, and electricity procured on the hourly wholesale market (Table 8). I assume that only the nuclear and large hydroelectric plants are owned and operated by the utilities. All other thermal generation plants are assumed to be owned and operated by independent power producers, which participate in the wholesale market.[59] Both nuclear and large hydroelectric plants are assumed to be generating at full capacity in all of the scenarios considered, and hence the annual fuel, operation, and maintenance costs for nuclear and hydro generation are equivalent for all scenarios (although the dispatch is optimized and different from one scenario to another).[60] In the 33% RE with high storage scenario, I "force" additional pumped hydro storage in the system (i.e., additional pumped hydro is not picked by the capacity-expansion model but imposed, as is the renewable generation in each scenario); costs are recovered through the rates, assuming a levelized cost of energy (LCOE) of about $722/kW-yr, from E3's Pro Forma calculator (E3, 2010b) and using capital cost assumptions from the U.S. EIA (2010). The costs of T&D are estimated by taking a load-weighted average of current T&D costs for Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and SDG&E, California's three largest investor-owned utilities (IOUs, $0.073/kWh)[61]. I also assume that in 2030 there are miscellaneous charges equal in magnitude to the public service program, reliability services, and other charges in today's rates for the three IOUs ($0.027/kWh).[62] The T&D and miscellaneous costs are not dependent on the electricity market scenario. Renewable procurement costs assume an LCOE of $0.10, $0.09, $0.15 per kWh for PV, wind, and CSP, respectively.[63] The total costs for the procurement of renewables depend on the renewable generation mix for each scenario. Finally, the costs of electricity purchased on the wholesale market are also recovered in the retail

[59] Although I recognize there may be bilateral contracts between power producers and utilities that do not participate in the wholesale market, I assume that in the long term these contracts approximate the cost of power traded on the wholesale market.

[60] The operations and maintenance costs for large hydroelectric plants are assumed to be $18.53/kW-yr and $3.67/MWh, in 2011 dollars, based on the INL Resource Database (O'Donnell et al., 2009). Those for nuclear plants are assumed to be $155.75/kW-yr and $5.56/MWh (O'Donnell et al., 2009).

[61] These volumetric transmission and distribution rates are very high compared to other regions in the US; some states, including Washington, Louisiana, or Arkansas, have total residential electricity rates that are similar to the T&D portion of CA IOU rates (EIA, 2013).

[62] The implicit assumption is that T&D infrastructure and miscellaneous costs are proportional to gross retail load (i.e., a linear growth in load will lead to a linear increase in T&D and miscellaneous costs). Also, by assuming that the T&D volumetric charges and miscellaneous charges are the same as current ones, I have maintained any existing cross-subsidies between the residential market and other customer segments.

[63] In addition, biomass and geothermal generation sources are assumed to have an LCOE of $0.10/kWh. The LCOEs for renewable generation are meant to reflect a gradual build-out until 2030 at a range of costs, which only affects average rates; the estimates are informed by a variety of sources including Alvarado (2012), Pietriszkiewicz (2012), and O'Donnell et al. (2009), as well as an understanding of current power purchase agreement pricing; prices accommodate transmission.

rate. The amount procured is what is needed to complement utility-owned and renewable generation to meet total load. Utility-owned and renewable generation only meet a portion of hourly load; the remainder is assumed to be purchased on the wholesale market at hourly market prices. Details for each of the rates are presented in the following section.

Table 8: Costs recovered through the residential retail rate

Costs	Fixed or varies across scenarios	Variable name	Notes
Generation purchased at wholesale price	Varies	Numerator in equation (1)	Generation in excess of renewable and utility-owned generation needed to meet retail load is purchased on the wholesale market.[64]
T&D infrastructure and miscellaneous	Fixed	$C_{T\&D}$	Based on current California utility rates and gross retail sales.
Utility-owned generation	Fixed	C_{uog}	Costs to run and maintain hydro and nuclear plants. Capital costs are assumed to be fully depreciated by 2030.[65]
RE purchase	Varies	C_{RE}	Weighted average of LCOEs for each generation type; for PV, consider wholesale purchases only (utility scale).

4.2.4.2 Impact of behind-the-meter PV on retail rates

In this study, I consider two compensation schemes for behind-the-meter residential PV: net metering and hourly netting. With net metering, customers receive bill credits for PV generation at the applicable retail rate (i.e., both shaded areas in Figure 38 are compensated with the retail rate). With hourly netting, PV generation can displace consumption of electricity within the hour, but any excess electricity generated within the hour is compensated at the prevailing hourly wholesale price as bill credits (i.e., the blue/solid shaded area in Figure 38 representing hourly load displaced by PV generation is compensated at the retail rate, and the purple/patterned shaded area in Figure 38 representing hourly PV generation in excess of hourly load is compensated at the hourly wholesale rate). A customer's load profile partially determines the percentage of PV generation that is compensated at the wholesale price under hourly netting—the greater the coincidence between customer load and PV generation, the greater the percentage of PV generation compensated at the retail rate. Hourly netting could be considered to be partly analogous to how energy efficiency is effectively compensated through retail rates, in that reduction in hourly customer load – whether via energy efficiency or behind-the-meter PV – are

[64] Although utilities sometimes sign long-term bilateral contracts with generators, reducing electricity purchases in the wholesale market, I do not consider these in this study. However, the prices negotiated in these bilateral contracts reflect market conditions at time of signing contract, and assuming unbiased foresight of the renewable generation build-out, the results wouldn't be impacted systematically in one direction or the other.

[65] Utility-owned generation can be thought of as equivalent to long-term contracts, and are dealt with identically for cost recovery purposes.

effectively compensated at retail rates. In contrast to energy efficiency, however, PV can create net excess generation within the hour, which under hourly netting is assumed in this study to be compensated in the same way as a wholesale generator: through hourly wholesale market prices.

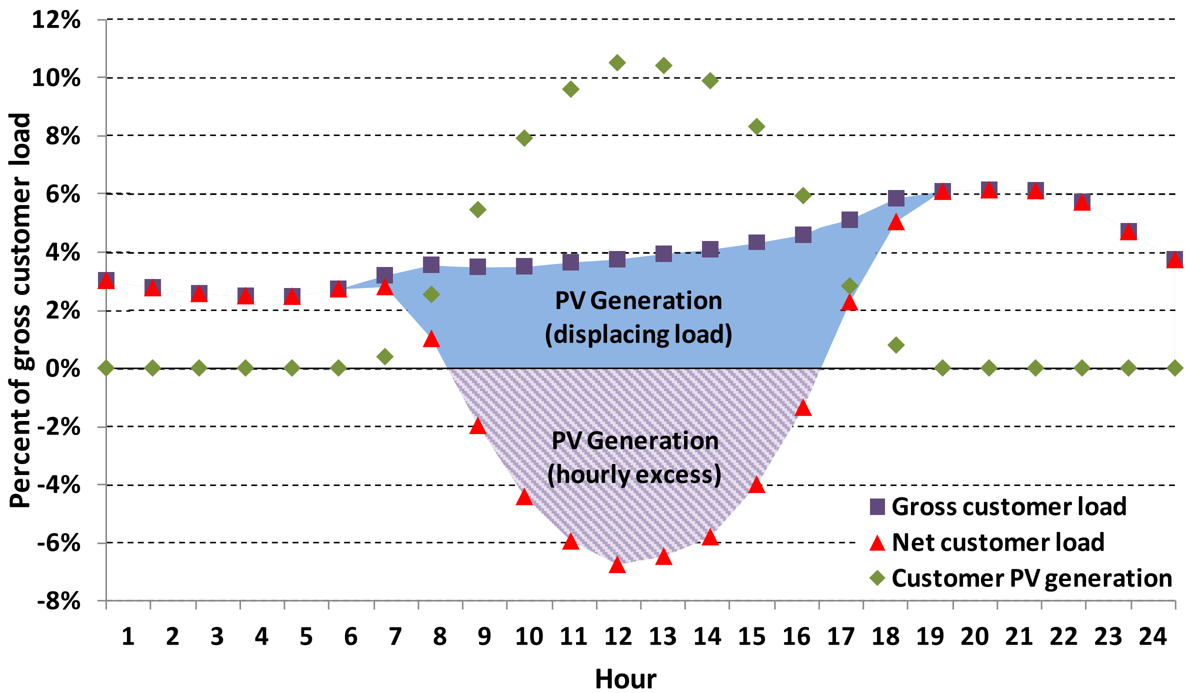

Figure 38: Example customer's gross load, net load, and PV generation, as a percentage of daily gross customer load, showing portion of PV generation that displaces load and the portion in excess of hourly load

Both residential PV compensation mechanisms (net metering and hourly netting) lead to reduced retail sales by utilities. Since the average wholesale price during times when PV generates is less than the average retail rate, the total reduction in wholesale costs is less than the total reduction in revenue due to net metering, and there is therefore a revenue shortfall, leading to an increase in rates.

Under net metering, net retail sales are equal to gross retail load minus total behind-the-meter generation (the areas shaded in blue and purple/patterned in Figure 38 summed over all PV customers). Under hourly netting, net retail sales are equal to gross retail load minus the portion of hourly PV generation that displaces hourly customer load (the blue area in Figure 38, summed over all customers).[66] Compensating behind-the-meter PV generation with hourly netting therefore increases the residential load that pays the full retail rate (relative to net metering) since under hourly netting less PV generation is compensated at the retail rate than under net metering.

[66] Under hourly netting, the purple/patterned section is compensated at the wholesale price, and is not counted as a reduction in retail sales – it is accounted for separately from the utility's perspective and its costs are recovered in retail rates. Note that this is the convention that has been chosen here, and that a different accounting convention could have been used yielding the same results.

Compensating hourly netted exports at the wholesale rate is one of many alternatives to net metering; other alternatives include compensation of all exported electricity at an avoided-cost rate or a fixed rate (such as under a FIT). However, compensating exports at the wholesale rate is a lower bound to most compensation options, and results with hourly netting should be interpreted as such; the avoided costs resulting from the exported PV generation are at the very least equal to the energy costs in the wholesale market, and would be higher if one accounted for local benefits, such as avoided losses or displaced T&D.

4.2.4.3 Flat rate

The first of the three retail rates I develop for each wholesale price scenario is the flat rate. The flat rate is not dependent on the time at which the electricity is consumed. The customer's marginal price for electricity consumption is the same whether the utility's cost of providing each additional kilowatt-hour is low (in the middle of the night, for example) or very high (during critical peak times).

There are two components to the calculated flat rate: a volumetric charge derived from the utility's wholesale market purchases, R_{gen}, and a volumetric charge to recover all other costs discussed in Section 0, R_{adder}. R_{gen} is the portion of the retail rate that recovers the total cost of wholesale purchases. Each hour, the portion of total load[67] (net of behind-the-meter PV) not met by utility-scale RE and utility-owned generation is assumed to be purchased on the wholesale market. I define the net residential load as the residential load not displaced by the portion of the behind-the-meter PV generation compensated at the full retail rate (i.e., both the blue/solid and the purple/patterned shaded areas in Figure 38 for net metering, and only the blue/solid shaded area for hourly netting). In summary:

$$R_{gen} = \frac{\sum_h \left(L_{h,res} - G_{h,res\,PV}\right) \cdot \left(1 - r_{h,uog} - r_{h,util\,RE}\right) \cdot p_h}{\sum_h \left(L_{h,res} - G_{h,res\,PV}\right)} \tag{3}$$

where $L_{h,res}$ is the residential load in hour h, $G_{h,resPV}$ is the residential PV generation compensated at the full retail rate in hour h, $r_{h,uog}$ is utility-owned generation as a percentage of net load in hour h (after deducting behind-the-meter PV), $r_{h,util\,RE}$ is utility renewable generation as a percentage of net load in hour h, and p_h is the wholesale price in hour h.

The volumetric adder, R_{adder}, is calculated by dividing all other costs by the billable residential load. Here I assume that the residential sector is responsible for residential T&D costs (i.e. proportion of total T&D costs attributable to residential load) and a proportion of the utility-owned and renewable electricity generation costs. This proportion is set to the residential percentage of total retail load. In summary:

---

[67] Total CAISO residential load profiles for 2004 are approximated using SCE's and PG&E's posted dynamic profiles for residential customers. The SDG&E dynamic profile was not available, so the SCE profile shape was used. Each IOU load profile shape was then scaled to the 2004 proportions, and the sum of the three was then scaled to represent 32% of total load. The scaling factors were extracted from CEC (2012).

$$R_{adder} = \frac{(C_{T\&D} + C_{uog} + C_{RE}) \cdot r_{res}}{\sum_h (L_{h,res} - G_{h,res\ PV})} \tag{4}$$

where $C_{T\&D}$ is the total T&D and miscellaneous costs, C_{uog} is the costs of utility-owned generation, C_{RE} is the total costs of RE procurement, and r_{res} is the residential percentage of total retail load (net of behind-the-meter generation).

4.2.4.4 Time-of-use rate

Under the TOU rate, residential customers are charged different volumetric rates depending on the time at which the electricity is consumed. I divided the year into two seasons (a high-priced and a low-priced season) and three rate levels in each season (peak, mid-peak, and low). In each season, the TOU rate periods are defined differently for business and non-business days.

Similar to the flat rate, the TOU rate has two components: R_{gen} and R_{adder}. The volumetric adder, R_{adder}, is the same as for the flat rate and is calculated from the utility-owned generation costs, RE procurement costs, T&D costs, and miscellaneous costs. The portion of the bill derived from wholesale purchases, $R_{gen,T}$, is different for each of the TOU periods *T* (low, mid, and high) for each of the seasons and is calculated in equation (5).

$$R_{gen,T} = \frac{\sum_{h \in T} (L_{h,res} - G_{h,res\ PV}) \cdot (1 - r_{h,uog} - r_{h,util\ RE}) \cdot p_h}{\sum_{h \in T} (L_{h,res} - G_{h,res\ PV})} \tag{5}$$

The numerator in equation (5) is the total cost for electricity purchased in period *T* on the wholesale market, and the denominator is the residential load net of PV generation compensated at total retail rate in period *T*. When $R_{gen,mid}$ is less than 5% lower than $R_{gen,peak}$, the two periods are combined into a single mid-peak period (i.e., the peak period is eliminated), and $R_{gen,mid}$ is recalculated.

The seasons and TOU periods for each of the seasons are calculated using k-means clustering algorithms, allowing for a systematic determination of TOU periods and season from hourly wholesale market prices. This method partitions wholesale prices into clusters of contiguous time periods. The clusters are chosen to minimize the sum of square error from the mean of the cluster. Similar methods to determine TOU rates using a variety of clustering techniques have previously been developed and described in Dobrow and Lingaraj (1988), Micali and Heunis (2010), Pollock and Shumikina (2010), and E3 (2009). More specifically, the seasons are determined by:

1) Selecting two initial centroids (zero and maximum average daily price)
2) Finding two clusters of contiguous days (S_1 and S_2) that minimize:

$$\sum_{j=1}^{2} \sum_{d \in S_j} \left(p_d - \overline{p_j}\right)^2 \tag{6}$$

where p_d is the mean daily price in day d and $\overline{p_j}$ is the mean daily price in S_j. I assume that each season begins on the first day of the month and has a minimum of 4 months.

3) Recalculating the centroids $\left(\frac{\sum_{d \in S_j} p_d}{N_j} \; for \; j = 1, 2\right)$, where N_j is the number of days in the cluster j.
4) Repeating steps 1-3 until the centroids converge.

Because there are only 30 season combinations possible, the centroids usually converge within two iterations. This algorithm results in two single seasons (the "high-priced" and "low-priced" seasons).

A similar procedure is repeated to determine TOU periods for business days (weekdays excluding federal holidays) and non-business days (including weekends and federal holidays) in each scenario. I assume that business days have three TOU periods (peak, mid-peak, and low priced), and non-business days have two TOU periods (mid-peak and low). TOU periods are a minimum of 2 hours in length, and a business day can have up to two peak periods. Each day can have a bimodal price distribution to allow for two peaks within a single day, if necessary. TOU periods are structured as follows: low period – mid period – high period – mid period – low period – mid period – high period – mid period – low period. However, any period may be empty, and hence price patterns for a given day are not necessarily bimodal. The first period can begin at any hour of the day (i.e., allowing midnight to be in the mid or high TOU period). The high period has a maximum of 6 consecutive hours, and no period can be less than 2 consecutive hours in length. If there are only two periods in a day, there is no mid period.

In order to ensure that the TOU periods are not overly dependent on particular events (such as a single wholesale price spike), I adopt a two-step approach to determining TOU period definitions. The general approach is to determine TOU periods for each individual day within a season, develop a single weighted-average day type (for business and non-business days), and determine TOU periods from each of the average day types.

More specifically, TOU periods for business days are determined by the following algorithm. For each business day in a particular season:

1) Selecting three initial centroids (zero, the mean hourly price, and the maximum hourly price)
2) Finding the three clusters, or TOU periods, of contiguous hours (T_1, T_2, and T_3) that minimize:

$$\sum_{i=1}^{3} \sum_{h \in T_i} (p_h - \overline{p_\iota})^2 \quad (7)$$

where p_h is the wholesale electricity price hour h and $\overline{p_\iota}$ is the mean price in T_j.

3) Recalculating the centroids $\left(\frac{\sum_{h \in T_i} p_h}{N_i} \; for \; i = 1, 2\right)$
4) Repeating steps 1-3 until centroids converge.

This results in periods definitions (T_1, T_2, and T_3) for each business day for a particular season. I then create a single weighted-average type day. Let:

$$\boldsymbol{S}_{d,h} = \begin{cases} \bar{P}_{low} \; if \; h \in T_{low} \\ \bar{P}_{mid} \; if \; h \in T_{mid} \\ \bar{P}_{high} \; if \; h \in T_{high} \end{cases} \quad (8)$$

where $\bar{P}_{low}$, $\bar{P}_{mid}$, and $\bar{P}_{high}$ are the average prices for all hours of all days in T_{low}, T_{mid}, and T_{high}, respectively.

$\boldsymbol{S}$ is a matrix of B rows and 24 columns, where B is the number of business days in that season.

5) Let:

$$\bar{\boldsymbol{S}}_h = \frac{\sum_d \boldsymbol{S}_{d,h}}{B} \quad (9)$$

$\bar{\boldsymbol{S}}$ is a single vector representation of a business day with 24 values (one for each hour).

6) Repeat clustering algorithm from steps 1-4 to calculate final business period definitions.

Non-business periods are calculated using a similar algorithm. However, non-business days only have low- and mid-priced periods, and hence the daily price pattern can have the following structure: low period – mid period – low period – mid period – low period. Similar to the business days, any of these periods may be empty (i.e., a bimodal price pattern is not forced by the algorithm).

4.2.4.5 Real-time pricing

Under the RTP rate, customers' marginal retail rate can change every hour and is tied to wholesale market prices. Although the variable portion of the RTP rate is set to the wholesale price, additional revenue is necessary to recover the full costs of service (including T&D, RE purchases, and utility-owned generation). This residual revenue requirement (*RRR*) is the difference between the total revenue requirement and the revenue from the variable portion of the bill, or:

$$RRR = \left(\left(C_{T\&D} + C_{uog} + C_{RE}\right) \cdot r_{res}\right) + \sum_h \left(L_{h,res} - G_{h,res\ PV}\right) \cdot \left(1 - r_{h,uog} - r_{h,util\ RE}\right) \cdot p_h - \sum_h \left(\left(L_{h,res} - G_{h,res\ PV}\right) \cdot P_h\right) \tag{10}$$

The *RRR* is assumed to be recovered through a volumetric charge for all residential customers,[68] which I term the residual revenue adder (R_{RRA}).

$$R_{RRA} = \frac{RRR}{\sum_h \left(L_{h,res} - G_{h,res\ PV}\right)} \tag{11}$$

4.2.5 Side analyses methodology: Alternative wholesale market design and retail rate structures

4.2.5.1 Lower price cap & time invariant capacity cost adder

A side analysis I have conducted is the computation of rates based on an electricity market with lower price caps, and where capacity costs are recovered via a volumetric adder, evenly spread over all electricity consumption. This effectively changes the rate structure so that instead of the generation component of the rate (R_{gen}) being based on wholesale prices that can reach \$10,000/MWh, I use the same output from the capacity expansion and dispatch model described in section 4.2.3, but I limit the wholesale electricity price ($p_{h,cap}$) such that:

$$p_{h,cap} = \begin{cases} p_h & if\ p_h \leq 1{,}000 \\ 1{,}000 & if\ p_h > 1{,}000 \end{cases} \tag{12}$$

For the generators selling power during peak hours when prices were higher than \$1000/MWh under the higher price cap, the lost income is recovered by the capacity cost adder (R_{cap}). This ensures that those plants that depend on these high payments to recover their capital costs provide sufficient capacity in those peak demand hours; the revenue requirement with a lower price cap and a capacity cost adder is the same than with a higher wholesale price cap. Similar to R_{gen} in equation (3), in section 4.2.4.3, R_{cap} is then calculated:

[68] Another option is to recover these costs through a fixed per-customer charge. This RTP rate design is not evaluated here to limit the scope of the investigation, but it merits further exploration. See the conclusions (Section 4.5) for a discussion of how implementing a fixed customer charge could impact results.

$$R_{cap} = \frac{\sum_{h\in(p_h>1000)}(p_h - 1000)\cdot\left(L_{h,res} - G_{h,res\,PV}\right)\cdot\left(1 - r_{h,uog} - r_{h,util\,RE}\right)}{\sum_h\left(L_{h,res} - G_{h,res\,PV}\right)} \tag{13}$$

where p_h is the wholesale price in hour h, $L_{h,res}$ is the residential load in hour h, $G_{h,resPV}$ is the residential PV generation compensated at the full retail rate in hour h, $r_{h,uog}$ is utility-owned generation as a percentage of net load in hour h (after deducting behind-the-meter PV), and $r_{h,util\,RE}$ is utility renewable generation as a percentage of net load in hour h.[69] In this way:

$$\begin{aligned}\sum_h p_h\cdot\left(L_{h,res} - G_{h,res\,PV}\right)\cdot\left(1 - r_{h,uog} - r_{h,util\,RE}\right) &= \sum_h p_{h,cap}\cdot\left(L_{h,res} - G_{h,res\,PV}\right)\cdot\left(1 - r_{h,uog} - r_{h,util\,RE}\right) + R_{cap} \\ &\quad\cdot\sum_h\left(L_{h,res} - G_{h,res\,PV}\right)\cdot\left(1 - r_{h,uog} - r_{h,util\,RE}\right) \\ &= \sum_h\left(p_{h,cap} + R_{cap}\right)\cdot\left(L_{h,res} - G_{h,res\,PV}\right)\cdot\left(1 - r_{h,uog} - r_{h,util\,RE}\right)\end{aligned} \tag{14}$$

where $p_{h,cap}$ is the new wholesale electricity price series over all hours, capped at $1000/MWh. In words, the capacity cost adder (R_{cap}) is defined such that the total costs of purchasing wholesale electricity under the higher price cap is equal to the sum of the costs purchasing wholesale electricity under the lower price cap and the total revenue from the capacity cost adder. This also implies that, for the flat rate:

$$\begin{aligned}R_{gen,cap} &= \frac{\sum_h\left(p_{h,cap} + R_{cap}\right)\cdot\left(L_{h,res} - G_{h,res\,PV}\right)\cdot\left(1 - r_{h,uog} - r_{h,util\,RE}\right)}{\sum_h\left(L_{h,res} - G_{h,res\,PV}\right)} \\ &= \frac{\sum_h\ p_h\cdot\left(L_{h,res} - G_{h,res\,PV}\right)\cdot\left(1 - r_{h,uog} - r_{h,util\,RE}\right)}{\sum_h\left(L_{h,res} - G_{h,res\,PV}\right)} = R_{gen}\end{aligned} \tag{15}$$

Hence the flat rate under the lower price plus the capacity adder is equal to the flat rate under the higher price cap, a result of how R_{cap} is defined in equation (14).

[69] The last factor $\left(1 - r_{h,uog} - r_{h,util\,RE}\right)$ is introduced because only a portion of the total residential load is purchased on the wholesale market (that portion which is not generated by utility-owned generation or by renewable energy generation).

I recalculated all rates (with net metering and hourly netting) using this time series for the reference scenario and the 33% renewable electricity scenario, where all procedures are similar to those described in sections 4.2.4.3, 4.2.4.4, and 4.2.4.5, except that the capacity cost adder, $p_{h,cap}$, is added to the rate at all hours.

4.2.5.2 Two-part tariff and HOOP rates

I will consider two types of two-part tariffs in this analysis: one with a fixed customer charge that is the same for both solar and non-solar consumers, and a HOOP rate with 4 different customer charges which can change for a customer who adds PV. These rates will be calculated under the reference scenario and the 33% renewable mix scenario.

First, I consider the two-part tariff with a uniform fixed fee, which recovers utilities' fixed costs through a customer charge that does not vary with customers' annual consumption.[70] With net metering and hourly netting, customers cannot displace any part of the customer charge. The variable portion of the rate – that can be displaced by PV generation – only recovers the energy costs, which includes electricity purchased on the wholesale market, utility-owned generation, and renewable electricity generation. With the real-time rate, the customer's energy charge is assumed equal to the wholesale price each hour, and the fixed charge is determined by the residual revenue required to recover total utility costs.[71] The real-time rate is likely the most efficient rate, as it sets the volumetric cost to the marginal cost of generating electricity and the fixed cost to recover all revenue shortfalls. However, I recognize that this rate likely recovers too many of the fixed costs from PV customers, and hence may be a lower bound to what a utility may actually implement, as PV has the ability to displace some fixed costs, such as offsetting T&D upgrades, and this rate does not take into consideration any of the potential benefits of behind-the-meter PV such as reduced line losses, and environmental benefits, for example. See, for example, Ràbago et al. (2012) for a review of the potential benefits of PV not accounted for in this analysis.

As long as the customer charges do not change with the installation of a PV system, whether the charges are different for different classes of customers is not relevant to the value of bill savings from behind-the-meter PV. However, with HOOP rates, Friedman suggests Public Utility Commissions consider a "more favorable fixed fee" for PV customers, as a mechanism to subsidize PV systems. It is no different to subsidize PV than to subsidize other customer groups (such as those living in the California desert areas who have a higher baseline allotment for their increasing block pricing rates), the paper argues (Friedman, 2012).

With HOOP rates, customers are divided into a number of groups, each of which has a different customer charge. These groups can be divided by historical average annual consumption over a number of years, for example, which determines their fixed fee (a higher fixed fee for the groups with historical average higher electricity consumption). The resulting

[70] The fixed charge includes recovery of transmission and distribution infrastructure, miscellaneous charges such as a public purpose program charge, and the fixed costs O&M related to utility-owned generation (hydro power plants, pumped storage, and nuclear plants).

[71] This is not quite equivalent to the RTP rate in the base analysis (with volumetric charges only), since none of the remaining charges are recovered with a volumetric charge. Thus comparisons between the RTP rate in the base analysis and with a customer charge will not be made directly in figures or the text.

fixed fee could then be reduced when a PV system is installed, by allocating to a new group using the customers expected net consumption (annual historical average load minus expected annual PV generation). This plan would continue to provide an incentive for electricity customers to install PV generation, potentially reflecting additional value not covered by the standard fixed fee, such as environmental benefits, reduced line losses, etc.[72] In addition, I consider a HOOP rate with four customer groups defined by their annual consumption, using the same customer data sample as previously. Customers are grouped into one of four customer groups, based on annual electricity consumption; the bottom quartile of customers in terms of annual load is in group 1, 2nd quartile in group 2, 3rd in group 3, and 4th in group 4. The fixed fees are arranged such that:

$$F_g = 0.25 \cdot g \cdot F_4 \text{ for } g = 1, 2, \text{or } 3 \tag{16}$$

$$\frac{1}{4}\sum_{g=1}^{4} F_g = F_0 \tag{17}$$

where F_g is the customer charge for group g, and F_0 is the default customer charge without HOOP rates. This simple problem leads to the solutions: $F_1 = \frac{1}{2} F_0$, $F_1 = F_0$, $F_2 = \frac{3}{2} F_0$, $F_4 = 2\ F_0$.

To ensure full cost recovery, the utility must recover the lost revenue associated with a PV customer moving to a lower fee group, to compensate for the reduced revenue. This could be done by "redrawing" the groups each time a customer installs PV, but this would cause another customer to move into a more expensive group, which is problematic since that customer would face an increase in utility bills without a change in consumption patterns or quality of service. Alternatively, the fixed customer charges could be regularly adjusted upwards to account for this. The increase in customer charges would be equal to the aggregate reduction in PV customer bills divided by the total number of customers. Since the increase in customer charge for all customers is fully dependent on the sets of assumptions made (e.g. the percentage of customers who adopt PV, the PV system size, and for hourly netting, the customers' load profiles), I will focus this analysis on the bill savings for customers with PV resulting from a lower customer charge – under the assumption that the marginal increase in customer charge due to an additional customer installing PV is much lower than the decrease in customer charge for that customer resulting from moving from a higher customer charge group to a lower one.

4.2.5.3 Tiered rate

I create a tiered flat rate for all scenarios (i.e., a rate with increasing-block pricing [IBP] but without any time-differentiated pricing), for which the results are presented in Box 2. Since there is little theoretical rationale for the specific characteristics of any tiered flat rate, a number of

[72] Though this would also lead to an increase in the fixed customer charge for customers who do not own a PV system; this may lead to further inequities between participants and non-participants.

assumptions must be made regarding the size of the steps (in kWh) and the increase in rate with each step. In this study, the tiered flat rate has three tiers (including a baseline) and can be described fully in the following three equations to produce a unique solution.

$$t_{baseline} \cdot R_{gen,baseline} + t_2 \cdot R_{gen,2} + t_3 \cdot R_{gen,3} = R_{gen,flat} \tag{18}$$

$$\left(R_{gen,baseline} + R_{adder}\right) \cdot (1 + s_2) = R_{gen,2} + R_{adder} \tag{19}$$

$$\left(R_{gen,2} + R_{adder}\right) \cdot (1 + s_3) = R_{gen,3} + R_{adder} \tag{20}$$

where $R_{gen,baseline}$, $R_{gen,2}$, and $R_{gen,3}$ are the R_{gen} components for the baseline, second, and third tier, respectively; $t_{baseline}$, t_2, and t_3 are the percentages of net load attributed to the baseline, second, and third tier, respectively; s_2 and s_3 are the percent increase in rate from baseline to tier 2 and from tier 2 to tier 3, respectively. The value for each of these constants is summarized in Table 9.

Table 9: Assumptions for tiered flat rate

$t_{baseline}$	t_2	t_3	s_2	s_3
0.55	$0.50 \cdot t_{baseline}$	$1 - t_{baseline} - t_2$	50%	100%

These values are loosely based on the current tier structure for PG&E and SCE. The baseline amount in California is designed to cover 50%-60% of average load (hence a value of 55% was used). Tier 2 corresponds to consumption from 100% up to 150% of the baseline level, and Tier 3 corresponds to all consumption over that level. The step increase in total rate from baseline to Tier 2 is 50%, and the step increase from Tier 2 to Tier 3 is 100%. Baseline regions and seasonal levels are equivalent to those of the three major IOUs.[73]

4.2.6 Residential Customer Load and PV Generation Data

4.2.6.1 Customer interval load data

The analysis of the potential bill savings from PV relies on 15-minute interval load data from a large number of residential customers located throughout the service territories of PG&E, SCE, and SDG&E, none of which have PV systems installed. These data were originally collected as a part of California's Statewide Pricing Pilot (SPP), which sought to analyze changes in electricity consumption associated with peak-pricing rate structures. The analysis specifically uses data for the SPP control group of customers, who were not under peak-pricing rate structures. The original SPP control group dataset consisted of load data from 442 customers, who were chosen

[73] The three IOUs in California (SCE, PG&E, and SDG&E) have developed baseline regions based on climate zones and assign a baseline level of electricity consumption appropriate for each climate zone. Baseline regions with higher temperatures in the summer are allotted a higher baseline level than more temperate coastal regions, for example.

using Bayesian sampling techniques in order to reflect the diversity of California customers across climate zones (Charles River Associates, 2005).

Several steps were required to prepare the SPP load data for analysis, similar to the cleaning methodology in chapter 2. First, a common 12-month period was selected. The original data spanned 15 months, from May 19, 2003 to September 30, 2004. I used data from the last 12 months of this period (October 1, 2003 to September 30, 2004), as this was the period with the least amount of missing load data.[74] Second, two types of customers were removed from the dataset: multi-family housing (N = 133) and single-family customers with more than 7 cumulative days of missing or zero-value load data (N = 145). Third, gaps in the load data for the remaining customers were filled. For gaps of 4 continuous hours or less, the missing data were replaced with linearly interpolated values from the hours immediately preceding and following the gap. For gaps longer than 4 continuous hours, the entire day was replaced with data from the previous weekday/weekend (depending on whether the missing data occurred on a weekday or weekend).

After cleaning the raw data set, the resulting working dataset contained 226 customers, all of whom were on the flat rate. Each customer was then assigned to a utility and baseline region, using Geographic Information System software and the zip code data records contained within the SPP database.

Figure 39 shows the customer load distribution for the customers in the final data set. Customers in the sample consumed 8,568 kWh/year in the median, with a mean value of 9,431 kWh/year. This is higher than the household mean values for the three largest California utilities: 6,734 (PG&E), 6,783 (SCE), and 5,943 (SDG&E) kWh/year (US EIA, 2012b). However, it is lower than gross electricity consumption for existing net-metered customers: 13,776 (PG&E) and 17,208 (SCE) kWh/year (DeBenedictis, 2010). Net-metered customers, at least as of 2010, tend to consume more electricity and hence be in high-priced tiers, since the value of bill savings are highest for these customers (see Darghouth et al., 2011). As PV costs continue to decline and rates move away from tiered structures, the average consumption of PV customers may decline.

[74] The individual customer load and PV generation data are reordered to start with January 1, 2004 to September 30, 2004, followed by October 1, 2003 to December 31, 2003, to most closely match the demand and PV generation profiles, which were for January 1, 2004 to December 31, 2004 (i.e., the last 3 months of customer load data are not contemporaneous with the wholesale price profiles).

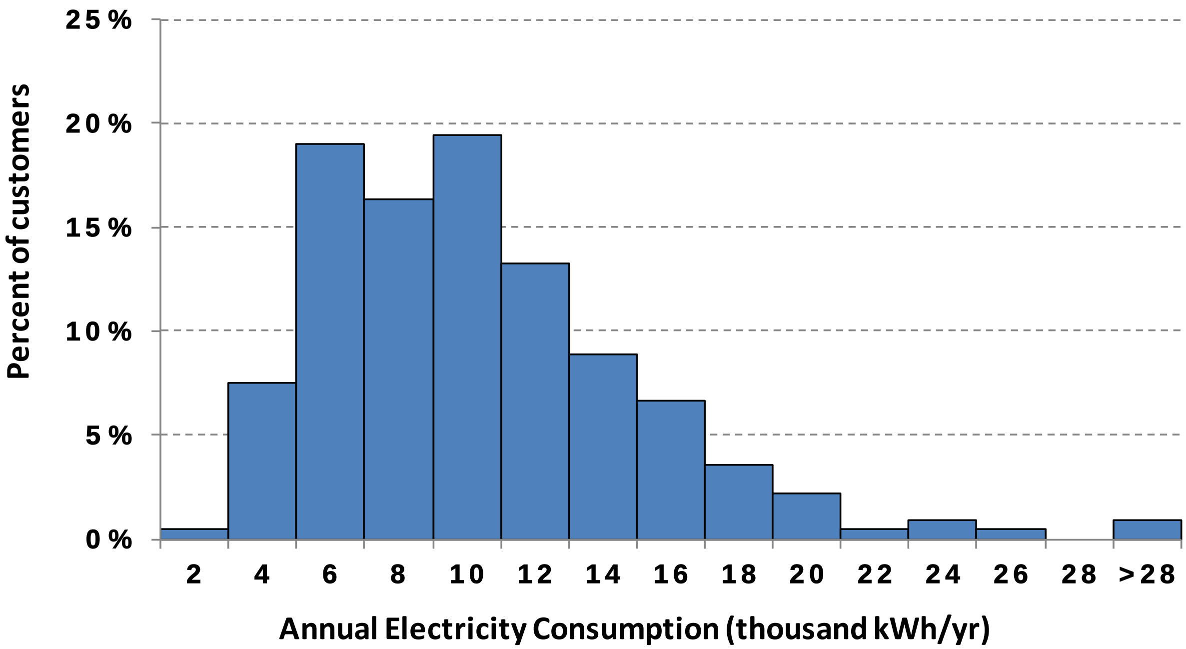

Figure 39: Annual load histogram for customers in the sample

The mean hourly load was calculated for each customer, as a percentage of total daily load. Figure 40 shows the load percentage distribution across all customers each hour. The box-and-whisker plots are independent from each other (i.e., the median customer in hour 1 is not necessarily the median customer in other hours). Overlaid are the mean percentages of daily CAISO residential load (approximated from SCE's and PG&E's dynamic load profiles, as explained in footnote 67), indicating that most customers in the sample have consumption patterns that are more heavily concentrated in the evening hours, when compared to the average residential customer in the CAISO[75]. This small sample bias is likely to impact the value of bill savings for customers in the sample under hourly netting, since the lower consumption period coincides with PV generation, increasing hourly netted exports and hence decreasing the value of bill savings. However, this does not impact higher-level conclusions from the study, as I am not looking to recreate results that are specific to California.

Elasticity of Demand

For the demand-response scenario, I assume that the aggregate total load has an elasticity of demand of -0.1 (i.e., a 10% reduction in demand for a doubling of price). This assumption is an input to the wholesale market price model, using the mean annual wholesale price with no elasticity as an anchor point from which the change in demand is calculated.

[75] This is confirmed when looking at the percentage change in bill values as customers switch from the flat rate to the time-of-use and real-time pricing rates; on average in the sample, customer bills increased by 1.2% when moving away from the flat to the TOU rate and 5.6% when moving away from the real-time pricing rate, for the reference scenario. Again, this indicates that customers tend to have peakier load profiles than average, and hence will benefit more from hourly netting and time-varying rates than the average population.

Also for the demand-response scenario, the aggregate residential load is adjusted from the 2004 load shape used for this analysis in order to calculate the cost of electricity purchased in the wholesale market to serve residential load. Although residential customers faced various marginal rates each month due to the tiered rate structure, the average rate in California in that year was \$0.1482/kWh (in 2011\$). I used this value as the anchor point from which I calculated the adjusted residential load. However, adjusting the residential load changes the retail rates—as per equations (3), (1), (5), and (11)—and hence multiple iterations of load adjustments are necessary until convergence.

Although aggregate and total residential customer load is adjusted for the purpose of calculating hourly wholesale prices and residential retail rates, individual customer load data for the purpose of the PV bill savings calculations are not adjusted in the demand-response scenario, in order not to conflate the effects of system-wide elasticity with the effects of individual customer elasticity on the value of bill savings from PV.

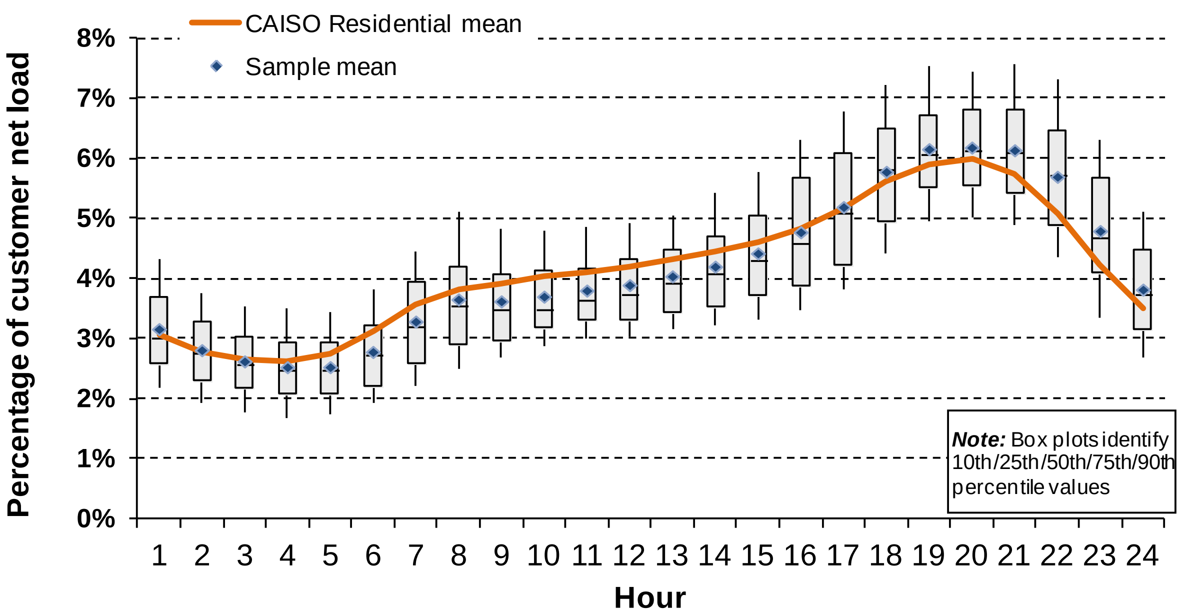

Figure 40: Percentage of consumption each hour for customers' mean day

4.2.6.2 Simulated customer PV generation data

Each customer within the load data sample was matched with simulated PV production data. For the analysis, I used PV simulation data from NREL, based on the PVFORM/PVWatts Model and the National Solar Radiation Database (NREL, 2007, 2010). The data consist of simulated hourly alternating-current electricity generation for a 1-kW system located at each of 73 weather stations located throughout California, derived from weather data for the same 12-month period as the customer load data (October 1, 2003 through September 30, 2004). Each customer within the load data set was assigned to the PV production data from the nearest of the 73 weather stations.

The simulated production was for a south-facing (180º azimuth) system with a 25º tilt, as this is the azimuth that generally produces the most kWh per kW in the northern hemisphere (Hummon et al., 2012), and 25º is a typical angle for a sloping rooftop.[76] For each paired set of customer load and PV production data, the simulated hourly PV production was scaled so that total annual PV generation would equal specific percentages of the customer's annual consumption (herein referred to as "PV-to-load ratio"). Three particular PV-to-load ratios (25%, 50%, and 75%) were used throughout the analysis. In comparison, among the actual population of residential PV customers in California, the average PV-to-load ratio is approximately 56% for PG&E residential customers and 62% for SCE residential customers as of 2010 (DeBenedictis, 2010), whereas a sample analyzed by Itron (2012) shows a PV-to-load ratio of 60% for SCE (N = 45) and 80% for a California-wide sample (N = 60). I use 75% as the default PV-to-load ratio in the analysis, although a number of figures also show results for 25% and 50% PV-to-load ratios.

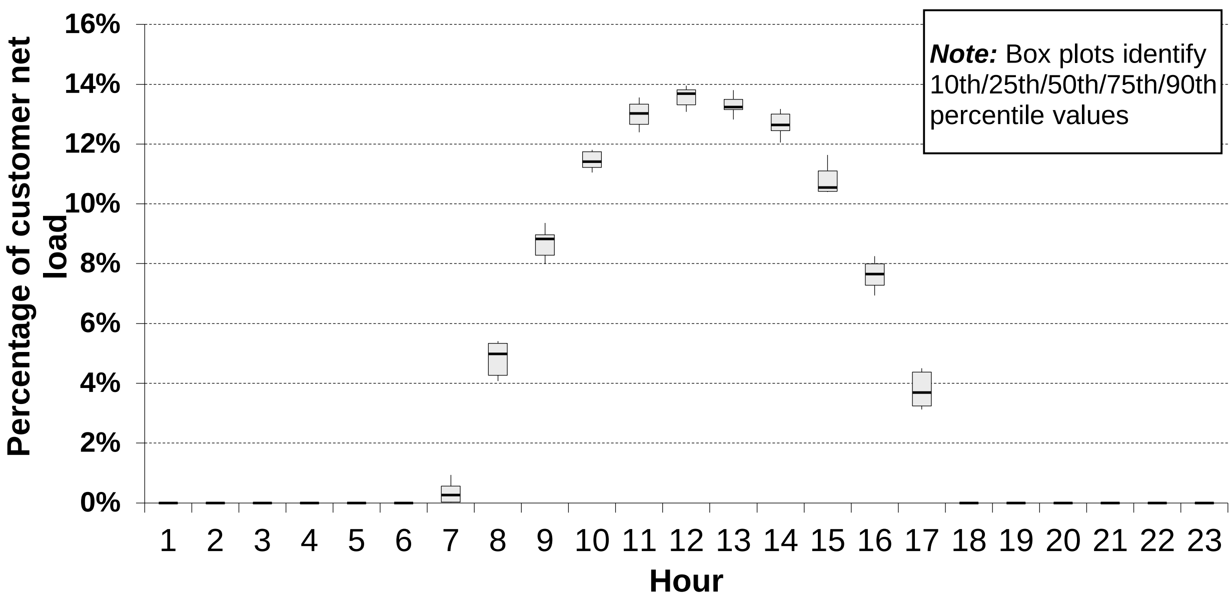

Figure 41: PV generation by hour, as a percentage of mean daily customer PV generation, for September 22, 2004 (Fall equinox).

Figure 41 shows box-and-whisker plots of percentage of customer PV generation each hour in the mean day for customers in the sample. Although the magnitude of PV generation (in kWh/kW) may differ from one customer to the next, the percentage of generation in each hour of a mean day is similar throughout all customers, as the entire sample is within California. Given that the customer PV systems are sized to match a specific percentage of annual load, the percentage of customer PV generation each hour is relevant to the analysis, rather than kWh/kW.

[76] The maximum kWh per kW may be at a different azimuth if the average insolation is asymmetrical in different periods (Mondol et al., 2007). Other PV module orientations may produce higher bill savings, such as those that maximize PV generation in higher-priced hours. However, Hummon et al. (2012) studied the effect using current rates in various U.S. regions and found it to be small, increasing the value of bill savings by only 1%-5%. In practice, distributed PV arrays may be oriented with any number of directions and tilts, depending on the structural features of the rooftop and site. See conclusions (section 4.5).

As seen in the figure, average daily PV generation begins at around 7 AM, peaks between the hours of 12 PM and 2 PM, and ends at 6 PM.

4.2.6.3 Hourly net consumption and excess PV generation

Since electricity bill calculations for PV customers with hourly netting use hourly net consumption (or hourly net export, when PV generation is greater than gross hourly load), I calculated net consumption (or net exports) as a percentage of gross hourly electricity for September 22, 2004, shown in Figure 42, for customers with a 25%, 50%, and 75% PV-to-load ratio. In the median case, customers' total hourly excess generation is 0%, 15%, and 37% of gross load for 25%, 50%, and 75% PV-to-load ratio, respectively. The average time at which residential customers' net consumption peaks does not change with increasing PV penetration, as it occurs after sunset, generally from 7 PM to 10 PM.

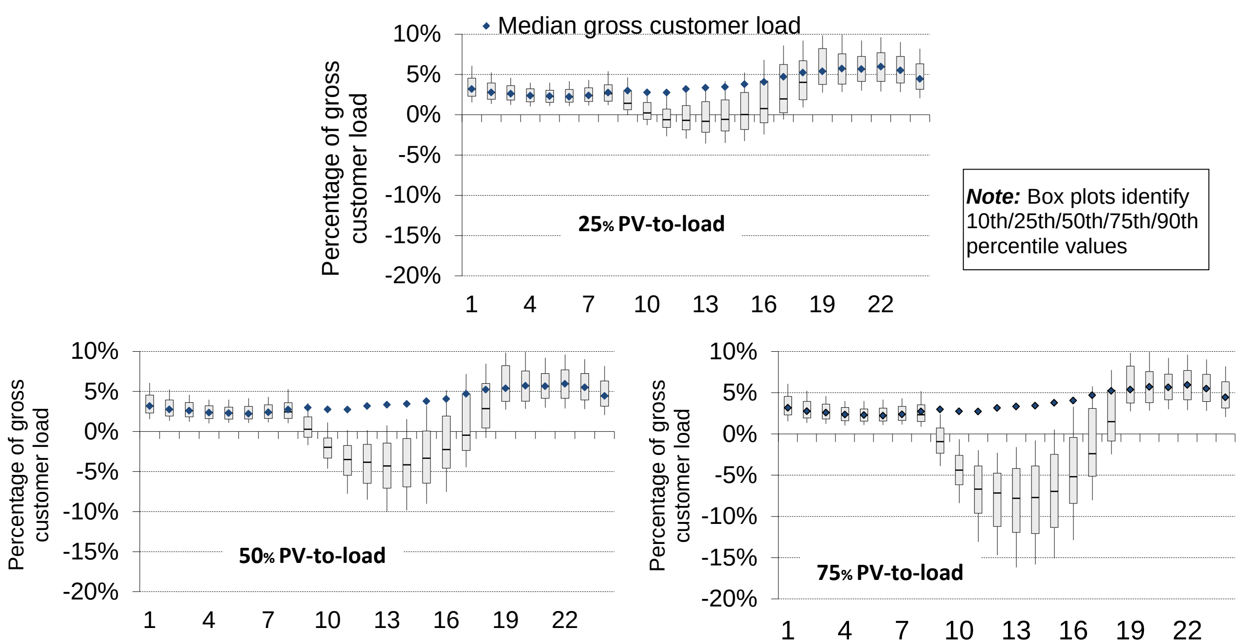

Figure 42: Net and gross hourly electricity for customers in sample, as percentage of gross customer load, September 22, 2004.

4.2.7 Calculating customer bills

Annual utility bills were computed for each customer, both with and without a PV system, under each of the residential rates calculated for each of the scenarios. Net metering and hourly netting were used to calculate bills for customers with PV systems. Details for each of these compensation mechanisms are presented below.

4.2.7.1 Net metering

For the flat rate, annual utility bills are calculated by multiplying the customer's annual net electricity consumption (the difference between gross electricity consumption and PV electricity production) by the flat rate for a given scenario. Since the PV system is always sized to meet 25%, 50%, and 75% of customer load, the annual bill for the flat rate is always positive under net metering.

For the TOU rate, monthly utility bills are calculated by first computing net electricity consumption within each TOU period, multiplying each by the appropriate TOU rate, and summing each of the TOU period bill components, as follows:

$$B_m = \sum_T \left(L_{m,T} - G_{m,T}\right) \cdot R_T \tag{21}$$

where B_m is the monthly bill for month *m*; $L_{m,T}$ is the customer's gross load for period *T* in month *m*; $G_{m,T}$ is the customer's PV generation for period *T* in month *m*; and, R_T is the TOU rate for period *T*. For any given month, a PV customer's bill can be negative if the credit from a high-priced period (during which a customer has a negative net load) is greater than the costs of lower-priced periods (during which a customer has a positive net load), even if the monthly net load is positive. The annual bill is the sum of the monthly bills.

For the RTP rate, customers are charged the hourly wholesale rate plus the residual revenue adder for their consumption. Annual bills are calculated as follows:

$$B_a = \sum_h (p_h + R_{RRA}) \cdot (L_h - G_h) \tag{22}$$

where B_a is the annual customer bill; p_h is the wholesale market electricity price in hour *h*; R_{RRA} is the residual revenue adder (as defined in equation (11)); L_h is gross customer load in hour *h*; and G_h is the customer's PV generation in hour *h*.

4.2.7.2 Hourly netting

Under the hourly netting compensation scheme, a customer can displace their consumption with PV generation within an hour (effectively compensated at the underlying retail rate), but any excess generation within that hour is compensated at the hourly wholesale market price. That is:

$$B_a = \sum_h B_h\,;\; B_h = \begin{cases} (L_h - G_h) \cdot R_h \; if \; G_h < L_h \\ (L_h - G_h) \cdot p_h \; if \; G_h > L_h \\ 0 \; if \; G_h = L_h \end{cases} \quad (23)$$

Where B_a is the customer's annual bill amount, B_h is the customer's bill amount for hour h, and R_h is the total retail rate for hour *h* (which is different for the flat, TOU, and RTP rates and is defined in Sections 4.2.4.3, 4.2.4.4, and 4.2.4.5, respectively).

4.2.7.3 Value of bill savings metric

To determine the value of the PV-derived utility bill savings to each customer, I compare the annual utility bill with and without a PV system, for each combination of PV-to-load ratio, retail rate structure, and PV compensation mechanism. Bill savings are expressed the bill savings on a $/kWh basis, in terms of the annual reduction in the utility bill per kWh generated by the PV system, as shown in the equation below.

$$Value\ of\ Bill\ Savings = \frac{B_{a,noPV} - B_{a,PV}}{G_a} \quad (24)$$

where $B_{a,noPV}$ is the customer's annual bill without PV, $B_{a,PV}$ is the customer's annual bill with PV,[77] and, G_a is the customer's total annual PV generation. Expressing the value of bill savings in terms of $/kWh allows for a direct comparison of electricity bills between residential customers with different loads as well as between alternate PV-to-load ratios.

4.3 Results: Central analysis

This section presents the calculated residential retail rates and the corresponding value of bill savings for customers in the sample for the scenarios introduced in section 4.2.1. First, I consider rates and value of bill savings for the reference scenario. I then present results for the isolation scenarios, using the reference as the baseline. Next, I introduce the rates and value of bill savings from PV for the 33% renewable penetration scenario, followed by results from the integration scenarios with 33% renewable penetration, relative to the 33% renewable scenario. In the final section, I summarize all results by presenting the value of bill savings from PV for all rate options, compensation schemes, and scenarios, relative to the median value of bill savings for customers with the flat rate and net metering under the reference scenario.

[77] The same rate option is assumed before and after PV installation (i.e., no rate switching is assumed after addition of PV).

This section presents results for the principle analysis; that is, I assume an energy-only wholesale market design and that retail rates are fully recovered through volumetric rates.

4.3.1 Reference scenario

The reference scenario provides baseline results, to understand and isolate the impacts of other scenarios on retail rates and the value of bill savings from residential PV. This scenario is neither meant to replicate current retail rates nor make an accurate prediction of how rates may evolve without the development of additional renewable generation.

4.3.1.1 Retail rates (reference scenario)

i. Flat rate

As described in Section 4.2.4.3, the flat rate consists of two components, one related to wholesale market purchases (R_{gen}) and one related to all of the utility's other costs to be recovered by residential rates (R_{adder}). These rate components, as calculated in the analysis under the reference scenario, and the total flat retail rate (R_{total}), are shown in Table 10.

Table 10: Flat rate under reference scenario (in $/kWh).

R_{adder}	R_{gen}[78]	R_{total}
0.115	0.064	0.179

The largest contributor to R_{adder} is the transmission, distribution, and miscellaneous component, which sums to $0.101/kWh (in 2011 US$, as with all other currency values in this chapter; see Appendix A for a more detailed breakdown of the adder). The total flat rate, R_{total}, is $0.179/kWh. As a comparison, the current average rate in California is $0.152/kWh (US EIA, 2012b), and the California Public Utilities Commission modeled reference case for 2020 (with similar levels of renewable penetration[79] but a lower total load) has an average rate of $0.162/kWh.

ii. Time-of-use rate

Time-of-use rates allow utilities to send price signals to customers based on historical wholesale price patterns. Using the wholesale price profile generated by the economic dispatch and investment model and the methods outlined in Section 4.2.4.4, TOU seasons and periods were determined for the reference case. The high-priced season was determined to be June-

[78] As noted previously, the flat rates are not identical under net metering and hourly netting, since the total net load differs by the total hourly net excess PV generation. However, the difference between the flat rates in scenarios with net metering and hourly netting are very small, less than one hundredth of a cent, since the amount of behind-the-meter generation as a percentage of total load is small. All rates presented in the body of the paper are for full net metering, as the differences with those for hourly netting are on the order of $0.001/kWh for all scenarios. All retail rates can be found in Appendix A.

[79] For details on the reference scenario, see E3 (2010c).

September (and hence October-May is the lower-priced season). The mean and median wholesale prices for business days and non-business days are plotted in Figure 43, for each season. For business days in the higher-priced season, the algorithm found a single peak TOU period preceded and followed by mid-peak and low periods, and only a mid and low period for low season business days. The highest-priced period (the peak period in the high season) occurs business days, from 1-7 PM. The low period is 11 PM to 9 AM, and the remaining hours are the mid-peak period. The other TOU period definitions are defined by the vertical red lines in each plot, which indicate the start of the next TOU period. Table 11 contains the resulting retail rates for each period.

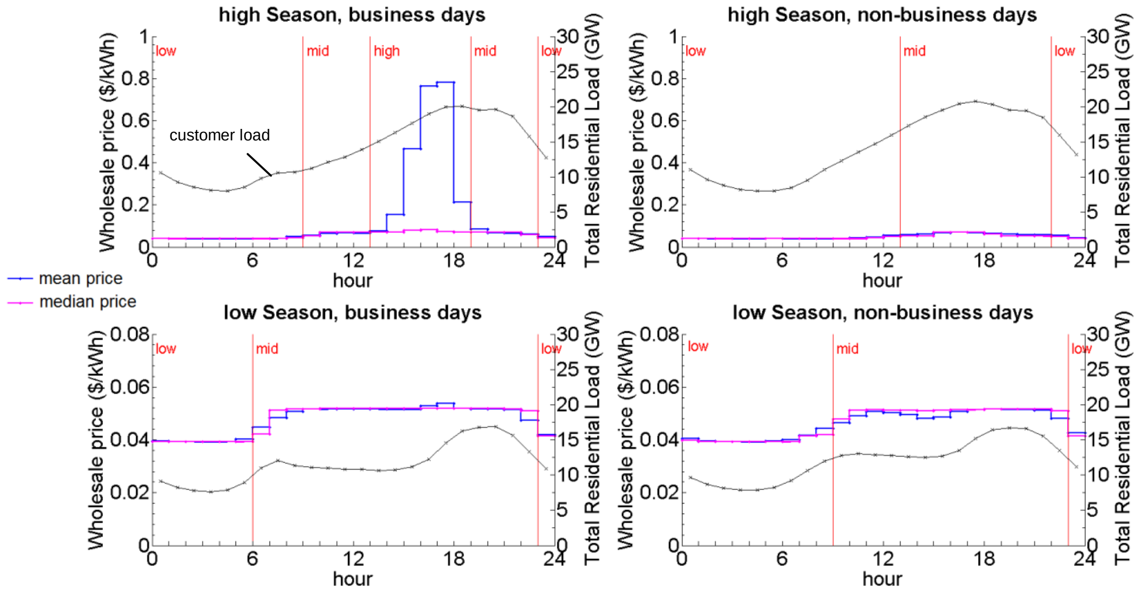

Figure 43: Mean and median wholesale electricity prices, aggregate residential load by TOU season, and TOU period definitions (reference scenario)[80]

Table 11: TOU rates (in $/kWh), for the reference scenario.

	Low Period	Mid Period	Peak Period
High Season	0.1446	0.1640	0.4930
Low Season	0.1418	0.1498	-

The average residential load curve for California is overlaid in Figure 43. Non-residential load peaks earlier in the day, and thus, with the low levels of renewable generation in the

[80] The large difference in the mean and median wholesale prices, particularly during the peak period in the high season, is due to the relatively small number of hours in which prices spike to $10/kWh. Although these events are relatively infrequent, the hours of the day in which they occur are consistent.

reference scenario, peak residential load in the high-priced season occurs at the tail end of the high TOU period. On average, during business days in the high season, 33% of total residential load (and 60% of the annual electricity bill to residential customers) is found to occur in the peak period. The annual percentages of residential load and bills for all periods are in Table 12. I observe a disproportionate percentage of cost during the high season's high period due to the high electricity rate in that period (8% of annual load accounts for 23% of total annual residential electricity bill).

Table 12: Percent of annual residential load and bills within each TOU period, calculated using total residential load profile, for the reference scenario. (Numbers do not sum to 100% due to rounding)

	Annual residential load within TOU period			**Annual residential bill within TOU period**		
	Low Period	**Mid Period**	**Peak Period**	**Low Period**	**Mid Period**	**Peak Period**
High Season	13.2%	15.5%	8.4%	10.7%	14.2%	23.1%
Low Season	15.9%	47.0%	-	12.6%	39.3%	-

A similar analysis of PV generation and compensation (with net metering) by period is shown in Table 13, using the PV generation profiles for the customer sample. Given the period definitions for the reference case, a majority of PV generation occurs during the low season's mid period (58%), although this accounts for only 43% of PV compensation (assuming that all generation is compensated at the prevailing retail rate, as is the case with net metering). Generation during the high season's high period only accounts for 15% of annual PV generation but contributes 36% of annual PV compensation under net metering. Under hourly netting, the percent of annual PV compensation within each TOU period depends on the individual customer's consumption profile, since net excess generation is effectively compensated at a different rate than generation displacing load within the hour.

Table 13: Mean annual PV generation and compensation (with net metering) by TOU period, for reference scenario

	Annual PV generation within TOU period			**Annual PV compensation within TOU period**		
	Low Period	**Mid Period**	**Peak Period**	**Low Period**	**Mid Period**	**Peak Period**
High Season	7.3%	18.4%	14.7%	5.2%	14.9%	35.8%
Low Season	1.2%	58.4%	-	0.8%	43.3%	-

iii. Real-time pricing rate

Real-time pricing passes the hourly wholesale price to the consumer, in addition to a residual revenue adder (R_{RRA}), which has a value of \$0.085/kWh for the reference scenario. The weighted average rate for residential customers with RTP is \$0.179/kWh, using the average total residential load.[81] As shown in Table 14, more than 99% of hours have wholesale prices less than \$0.1/kWh, and over 98% of residential load (net of behind-the-meter generation) occurs in these hours. However, residential load disproportionately occurs during higher-priced hours, which implies even larger proportions of total residential bills during these hours. Given the high price spikes that occur during times of scarcity pricing, about 25% of annual bills occur during hours when wholesale prices are greater than \$0.1/kWh. As discussed in Box 1, capacity costs are reflected in wholesale prices in this study, due to the energy-only market design, and hence payments in relatively few hours can account for the bulk of a customer's capacity payments with RTP.[82]

Table 14: Annual residential load and bill by wholesale electricity price bin

Wholesale price (\$/kWh)	Annual price distribution (%)	Annual residential load (%)	Annual residential bill (%)
0-0.05	44.5%	35.6%	25.2%
0.05-0.1	54.7%	62.7%	50.1%
0.1-10	0.9%	1.7%	24.8%

PV generation also disproportionally occurs during higher-priced hours in the reference case, even more so than residential load. Approximately 85% of annual PV generation occurs during hours with wholesale prices greater than \$0.05/kWh (Table 15), although these prices are found to occur in only 56% of hours in the year. Similarly, 1.9% of PV generation occurs during hours with high prices, \$0.1-\$10/kWh, although these prices occur during only 0.9% of hours in the year, resulting in over 24% of annual compensation, assuming net metering (i.e., PV is compensated at the retail rate). This disproportionately high percentage is due to the high price spikes that occur in a few hours, a result of scarcity pricing.

[81] This value is the same for net metering and hourly netting (when rounded to the nearest thousandth of a dollar).
[82] This is in contrast to most prevailing retail rates which distribute capacity costs equally through a volumetric adder.

Table 15: Mean annual residential PV generation and compensation (with net metering) by wholesale electricity price bin

Wholesale price ($/kWh)	Annual PV generation (%)	Annual PV compensation (%)
0-0.05	15.3%	10.9%
0.05-0.1	82.8%	65.0%
0.1-10	1.9%	24.2%

4.3.1.2 Value of bill savings (reference scenario)

I calculated annual utility bills for each customer from the dataset, both with and without a PV system, under each retail rate and PV compensation scheme and for each electricity market scenario. The calculations were repeated using PV system sizes meeting 25%, 50%, and 75% of annual load for each customer (i.e., 25%, 50%, and 75% PV-to-load ratios). For the reference scenario, the value of bill savings for customers under the flat rate with full net metering is $0.179/kWh, since all PV generation displaces consumption at the flat rate regardless of the customer's temporal load shape, consumption level, or PV system size.

Figure 44 plots the percentage difference from the value of bill savings from PV under the flat rate with net metering for all rates and both compensation schemes. The box plots in the figure show the distribution in value of bill savings for customers with a 75% PV-to-load ratio, and the square and 'X' markers are the median values for 25% and 50% PV-to-load ratios, respectively.

Customers under the TOU rate with net metering receive the greatest value from PV (a 13% increase, in the median), followed by those under the RTP rate with net metering (a 1% increase, in the median). Wholesale price peaks often occur from 4 to 6 PM, whereas PV generation peaks from noon to 2 PM,[83] and hence PV generation benefits from the averaging of wholesale prices over the peak TOU period, increasing the effective compensation rate of PV generation during its peak in the TOU rate in comparison to RTP. The increase in value from PV with RTP relative to the flat rate is low for two reasons. First, though PV generation is relatively concentrated at times when wholesale prices are high, residential load is also concentrated during high priced hours (peaking a couple of hours after price peaks). This results in the PV generation-weighted average wholesale price only being 3.7% higher than the residential load-weighted average wholesale price (in the median case). Since the flat rate is a residential load-weighted average of the wholesale price (plus an adder), the PV generation-weighted average of the wholesale price is only slightly higher than the flat rate. Second, 47% of the value of bill savings is from the residual revenue adder, which is a fixed volumetric charge and hence not time dependent. This

[83] Note that we assume PV system azimuth is due South. A more westerly orientation would improve the coincidence between peak PV generation and peak wholesale prices, although total PV generation levels would be lower.

further reduces the difference between the bill savings between the RTP and the flat rate. A more complete explanation is found in Appendix D.

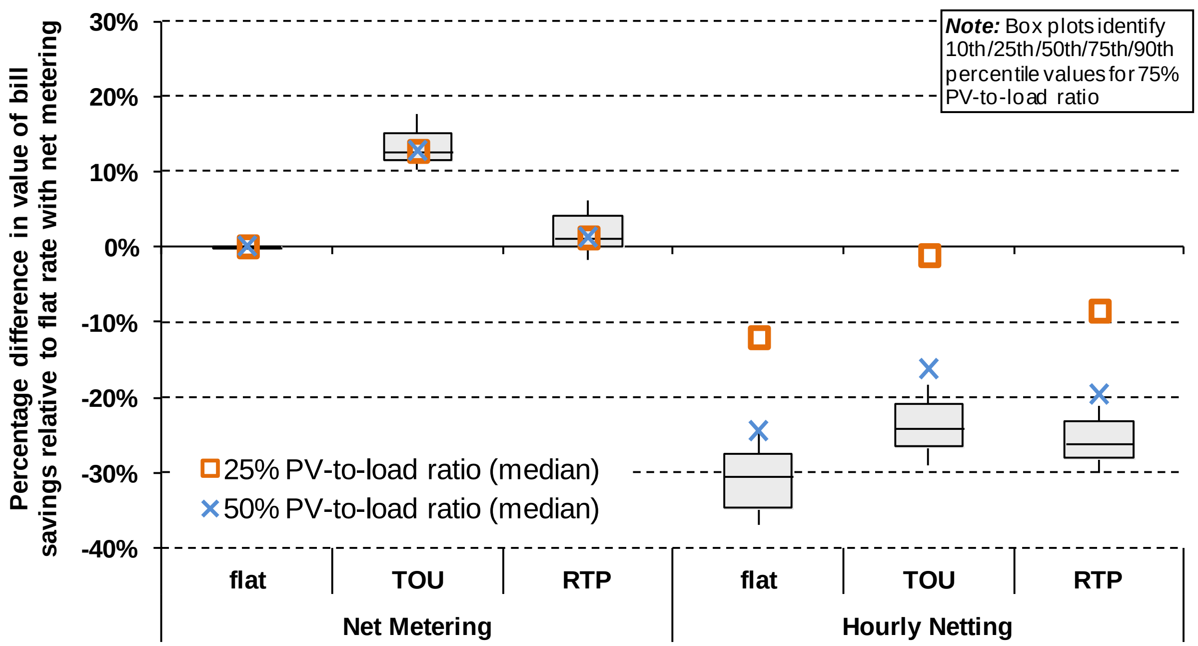

Figure 44: Value of bill savings relative to a flat rate with net metering (reference scenario)

With net metering, the variation in value of bill savings within each rate is due to the variation in temporal PV generation profiles in the sample. There is no variation in the value of bill savings for customers under the flat rate since there is no time-varying element to the flat rate, whereas the variation in bill savings under TOU rates is due to the differences in percentage of annual PV generation within the TOU periods. Because the PV systems are sized to meet a specific percentage of annual customer load, the annual kWh/kW produced are not relevant to the value of bill savings; only the PV generation profile shape determines what percentage of PV generation is in each TOU period or hour. The variation in value of bill savings across customers is greater when customers are compensated for their PV generation with hourly netting, because a customer's median bill savings depend on the amount and temporal profile of their hourly excess generation. Customers whose load profiles coincide better with their PV generation profile tend to have a higher value of bill savings, since this reduces hourly excess generation (compensated at the wholesale rate, which is often lower than the full retail rate). This explains all of the variation for customers under the flat rate with hourly netting and part of the variation for customers under the TOU and RTP rate with hourly netting (the remaining variation is due to the differences in PV generation profile, as for net metering).

All customers compensated with hourly netting receive less than under net metering, regardless of the retail rate, because hourly excess electricity is compensated at the hourly wholesale price. On average, the wholesale price at which customers' hourly excess generation is compensated is lower than the prevailing retail rate, leading to a decrease in value of bill savings with hourly netting (although the wholesale rate can be higher than the retail rate during a few very-high-priced hours). As with net metering, the flat rate provides the least value of bill savings from PV, followed by the RTP rate and the TOU rate. The differences in value of bill savings for hourly netting is not as pronounced between the three rate options as with net metering, because the hourly excess generation for each is compensated at the same price regardless of the rate option.

Under net metering, higher PV-to-load ratios—at least up to 75%—do not change the value of bill savings for customers, as seen in Figure 44. For any given customer, the value of bill savings per kWh generated depends only on the PV generation profile shape, which does not change for increasing PV-to-load ratios up to 75%[84] (see Figure 41). Under hourly netting, on the other hand, lower PV-to-load ratios imply lower levels of hourly excess PV generation. Hence a greater proportion of PV generation is compensated at the full retail rate, and the loss in bill savings compared to net metering is lower. For the flat rate with hourly netting, for example, the median value of bill offsets from PV is 30% lower than for the flat rate with net metering at a 75% PV-to-load ratio. This loss in value decreases to 25% and 12% for a 50% and 25% PV-to-load ratio, respectively, providing incentives for customers to limit their PV-to-load ratio under hourly netting in order to minimize hourly excess generation.

4.3.2 Isolation scenarios

Having analyzed the impact of various rate and PV compensation options on the reference scenario in the previous section, I now analyze the impact of specific changes in future electricity market scenarios. Five electricity market scenarios were developed, each identical to the reference scenario except for one attribute, to isolate the impact of this change; I call these isolation scenarios. These scenarios are described in section 4.2.1 and include a 15% PV, a 15% wind, and a $50/tonne carbon price scenario, as well as scenarios with high and low natural gas prices.

In this section, I compare the value of bill savings from PV for retail rates across the five scenarios. The retail rates calculated for the isolation scenarios are presented in 4.3.2. Figure 45 shows the percentage difference in the value of bill savings relative to the reference scenario for each combination of rate option and compensation mechanism and assuming a 75% PV-to-load ratio. For example, the blue diamonds in the figure indicate the change in value of bill savings from PV under the flat rate with net metering for each scenario. The figure illustrates how each rate option is impacted by the specific change in the isolation electricity market scenario. A summary figure, presented in section 4.3.6, includes how each rate option and isolation scenario is impacted relative to the flat rate with net metering.

For the 15% PV scenario, all rate and compensation options receive a lower value of bill savings than under the reference scenario, except for the flat rate with net metering. The flat rate with net metering is higher than for the reference scenario because of the higher costs of RE

[84] Most net-metering arrangements do not compensate solar generation at the retail rate if the net annual customer bill is negative. In many states, any negative bill credit at the end of a 1-year period is zeroed out, reducing average compensation per kWh generated. In California, any excess PV generation (i.e., for systems with PV-to-load ratios greater than 100%) is compensated at an avoided-cost rate lower than the retail rate, as per AB 920, again lowering the average per-kWh compensation for behind-the-meter solar. At PV-to-load ratios up to 75% these effects are not triggered but would be triggered at still-higher PV-to-load ratios.

procurement (C_{RE}) incorporated in the volumetric fixed cost adder (R_{adder}). All other rate option and compensation scheme permutations have a lower value of bill savings than for the reference case. Despite the increase in R_{adder}, there is still a reduction in value from bill savings under the TOU and RTP rates. The value of bill savings from PV decreases under the TOU and RTP rates with net metering by a median value of 19% and 22%, respectively, as PV generates at times when rates are low. These lower rates are driven by deflated wholesale prices during periods of high PV supply, a result of an abundance of zero marginal cost, non-dispatchable PV generation on the market in those hours. This also leads to a steep drop in wholesale prices when PV generates—even steeper than the corresponding drop in TOU and RTP retail rates (as these rates are dampened by the increased R_{adder}). Since any hourly excess PV generation is compensated at the wholesale price under hourly netting, the drop in value is more significant under hourly netting than that with net metering, where all PV is compensated at the retail rate. The value of bill savings under the flat rate with hourly netting decreases by almost 17% from the reference case, where the sharp decrease in wholesale prices during times of excess hourly PV generation offsets the increase in the flat rate. The TOU and RTP rates under hourly netting decrease by 31% and 34%, respectively.[85]

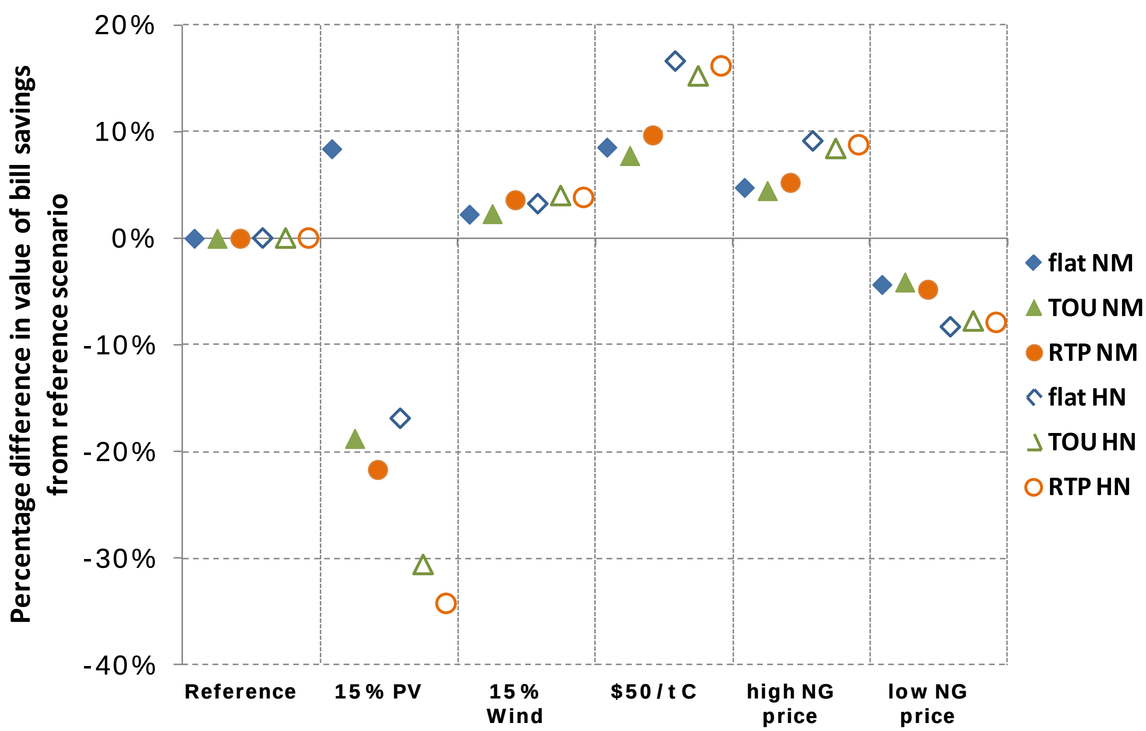

Figure 45: Value of bill savings for the isolation scenarios relative to the reference scenario's corresponding rate with net metering (NM) and hourly netting (HN). 75% PV-to-load ratio assumed.

---

[85] The increase in the volumetric fixed cost adder, R_{adder}, which is displaced by non-excess hourly PV generation, prevents an even sharper decline in the loss of value as compared with the reference scenario.

The 15% wind scenario has a similar impact on the value of bill savings from PV for all rate and PV compensation options. All rates increase slightly due to the additional procurement costs of wind energy, factored into R_{adder}, and wholesale electric rates at times when PV generates electricity are not impacted significantly. This is because there is little correlation between PV generation and wind generation profiles in California; wind primarily generates electricity in the evening, and hence wholesale rate impacts are not significant during times of PV generation.

A $50/ton carbon price results in higher marginal cost of generation for fossil fuel plants, the most carbon-intensive having the most significant fuel cost increases. This leads to a rise in all the rates, and hence an increase in the value of bill savings from the reference scenario. As seen in Figure 45, the addition of a carbon price results in similar value increase for all rates with net metering (8%-10%) and all rates with hourly netting (15%-17%). The carbon price has a larger impact for hourly netting than for net metering because hourly netting is more sensitive to changes in wholesale prices than net metering (again due to the dampening effect of R_{adder}).

The two scenarios with higher and lower natural gas prices also impact all rate options similarly for a given PV compensation scheme. Since natural gas plants are often on the margin during the times when PV generates, the change in natural gas prices impact the rates and value of bill savings from residential PV. The increase in natural gas prices to $7.97/Mbtu leads to a 4%-5% and 8%-9% increase in value of bill savings across all rates with net metering and hourly netting, respectively. A decrease to $4.95/Mbtu leads to a 4%-5% and 8% decrease in value with net metering and hourly netting, respectively. As with the carbon price scenario, the hourly netting compensation leads to a greater difference in value than net metering, for similar reasons.

Of the five market characteristics considered in the isolation scenarios, the value of bill savings is most sensitive to PV penetration. In the next section, I investigate this further by quantifying how value of bill savings is impacted by increased levels of PV penetration.

4.3.3 Increasing PV penetrations

In this section, I consider how the value of bill savings from PV may be impacted at varying levels of PV penetration and whether these impacts change linearly with increasing PV penetration under the assumptions and methods applied in this study. Results indicate that rising grid PV penetration levels have an increasing impact on retail rates and value of bill savings but not necessarily a linear one, depending on the type of retail rate and PV compensation scheme considered. As indicated by the diamonds in Figure 46, the median value of bill savings from residential PV is found to increase roughly proportionally with increasing grid PV penetration for customers under the flat rate and net metering. This is mostly the result of an assumed increasing flat rate due to the increase in PV electricity acquisition costs and the need to recover fixed costs due to utility revenue loss from customer-sited PV recovered through R_{adder}, the volumetric adder, with increasing PV penetration.

The median value of bill savings for customers under the TOU rate with net metering decreases continuously with increasing PV penetration, but the *rate* of decrease in value is much greater at lower PV penetrations. This is due to the TOU period definitions, particularly for the peak period in the high-priced season, which shift to later in the day away from peak solar generation. At 2.5% PV penetration, the peak period in the high-priced season shifts (2 hours later than for the reference case), which leads to a relatively high erosion in value of bill savings. The median percentage of annual PV generation occurring during the peak period in the high season is reduced by roughly 50%, leading to a sharp decline in value of bill savings (12%), highlighting the impact of TOU period definition. A shift in the peak period of a single hour can lead to a significant decline in bill savings, as PV generation drops relatively quickly after noon. This reduction is more significant than the increase in R_{adder}, leading to a net decrease in value of bill savings. The rate of reduction in value of bill savings for customers under TOU with net metering becomes shallower as peak periods shift to evening hours with no PV generation. The shift in the peak hours during the high-priced season can be observed in Table 16. As PV penetration increases, the peak period shifts to later in the day and become shorter.

Table 16. Shift in peak hours in peak season with increasing PV penetration.

PV Penetration	Peak hours in peak season
0.2%	1 pm – 7 pm
2.5%	3 pm – 9 pm
5.0%	4 pm – 10 pm
7.5%	4 pm – 10 pm
10%	5 pm – 10 pm
12.5%	6 pm – 10 pm
15%	6 pm – 9 pm

Under the RTP rate with net metering, the median value of bill savings reduces almost linearly until a 10% grid PV penetration, at which point the rate of reduction in value of bill savings starts to diminish, as seen by the round markers in Figure 46. The impact of additional PV on average PV compensation is diminished in this case because peak prices have already shifted to evening hours with no PV generation.

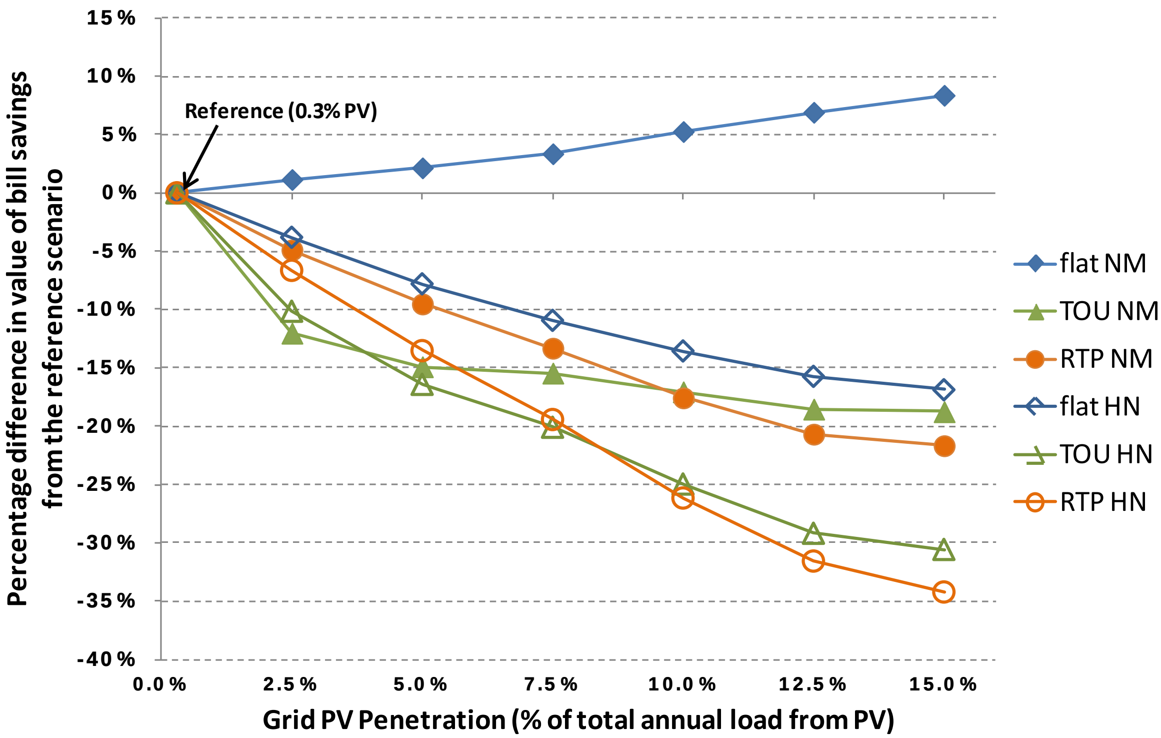

Figure 46: Value of bill savings from PV with increasing grid PV penetration levels, relative to the reference scenario's corresponding rate with net metering (NM) and hourly netting (HN). 75% PV-to-load ratio assumed.

With hourly netting, the median value of bill savings from residential PV decreases as grid PV penetration increases, for each retail rate, due to the decrease in value of the hourly excess PV generation compensated at the wholesale prices. The increase in R_{adder} is offset by the larger reduction in compensation for the hourly excess PV generation, resulting in a net decrease in value of bill savings. The *rate* of decrease in value of bill savings from PV under TOU with net metering is highest at lower PV penetrations before it starts to decline more gradually. This reduction in the marginal reduction in value is due to the peak period in the high season shifting towards the evening time, and with each shifted hour, a lower proportion of PV generation is compensated at the peak rate. The *rate* of decrease in value of bill savings for customers under the RTP rate with hourly netting is more constant than for those under the TOU rate with hourly netting because all of the compensation is linked to the wholesale price, which erodes at a more constant rate with increasing grid PV penetration.

Overall, it is clear that increasing PV penetration levels could lead to sizeable changes in the value of bill savings from residential PV, that these impacts occur even at relatively low levels of PV generation, and that retail rate and compensation scheme options are impacted differently depending on grid PV penetration levels.

4.3.4 33% Renewable energy mix scenario

The 33% RE mix scenario has a variety of renewable electricity generation technologies, including wind, PV, and CSP with storage (in a 50:35:15 ratio, respectively), in addition to slightly increased levels of biomass and geothermal electricity. I developed this scenario (which achieves California's 33% RPS target) since renewable generation is more likely to grow more evenly with respect to technologies than assumed in the isolation scenarios. The interactions and complements between different RE generation choices lead to impacts on retail rates, and hence bill savings from PV, that are most likely different than the sum of the impacts from the individual renewable technologies. This section presents the retail rates calculated from the wholesale market prices in this scenario, followed by an analysis of the value of bill savings from residential PV.

4.3.4.1 Retail rates (33% renewable mix scenario)

i. Flat rate

The time-invariant flat rate with net metering is $0.192/kWh for the 33% RE mix scenario. The volumetric fixed costs adder (R_{adder}) is higher than for the reference scenario, due to the additional costs of renewable electricity procurement, but the portion of the rate derived from wholesale market purchases is lower than for the reference scenario since the increased renewable electricity generation decreases the total electricity purchased on the wholesale market (Table 17).[86]

Table 17: Flat rate with the 33% renewable mix scenario, assuming all behind-the-meter PV is compensated with net metering

R_{adder}	R_{gen}	R_{total}
$0.140/kWh	$0.052/kWh	$0.192/kWh

ii. Time-of-use rate

With a 33% renewable penetration, the modeled wholesale price profiles are found to change considerably; the peak prices shift from mid-afternoon to early evening—when insolation and therefore PV generation tapers off. Although there is no change in the high- and low-priced seasons (i.e., the high season remains June-September), the TOU periods resulting from the wholesale prices change significantly from the reference scenario (Figure 47). The algorithm found a single peak TOU period preceded by mid-peak and low periods and followed by a mid-peak period for high-season business days and only a mid and low period for low-season business days. The highest-priced period (the peak period in the high season) occurs on business days from 5-9 PM; the low period is 12 AM to 1 PM, and the remaining hours are the mid-peak period. The other TOU period definitions for each day type are defined by the vertical red lines in the figure, which indicate the start of the next TOU period.

[86] Although R_{gen} is lower in the 33% RE mix scenario than in the reference scenario, this does not imply that the average cost of electricity purchased is lower. The average cost of electricity purchased is in fact higher, but R_{gen} is lower because less electricity is purchased on the wholesale market.

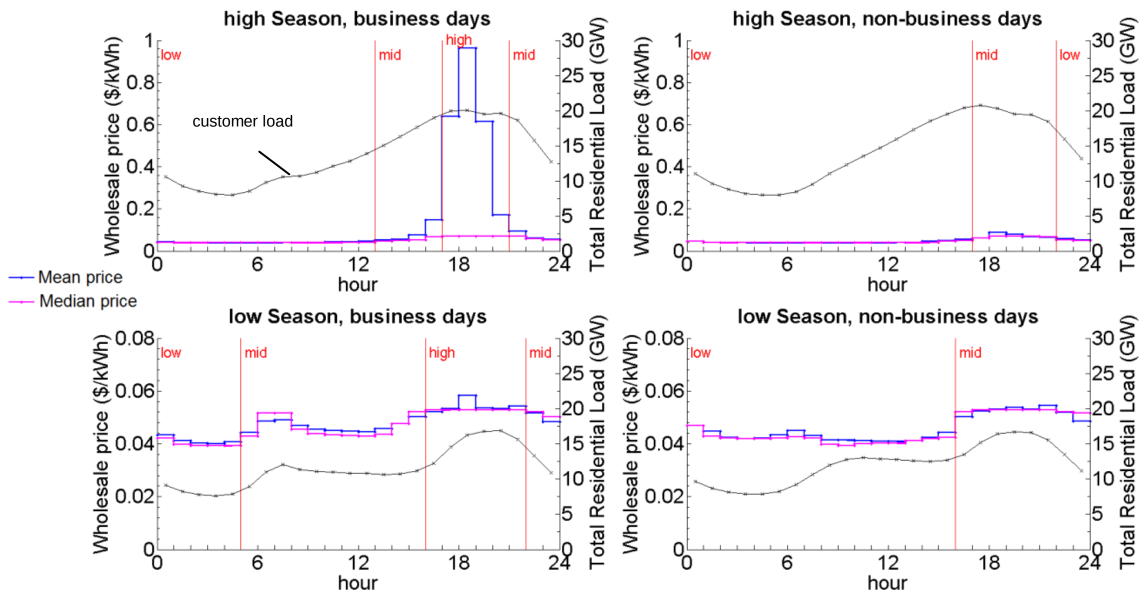

Figure 47: Average wholesale electricity prices, aggregate residential load by TOU season, and TOU period definitions (33% RE mix scenario)

Table 18 shows the retail rates within each period calculated assuming net metering. The prices for all periods are higher than for the reference scenario, in part due to the higher volumetric adder, R_{adder} (which is the same for the TOU and flat rates). The rate for the high-priced season's peak period is \$0.572/kWh, a 16% increase from that of the reference scenario, due to the narrower peak period, in addition to the volumetric adder.[87]

Table 18: TOU rates (in \$/kWh) for the 33% RE mix scenario

	Low Period	Mid Peak	Peak Period
High Season	0.1619	0.1859	0.5722
Low Season	0.1591	0.1641	0.1672

Under the 33% renewable energy mix scenario, the residential load is much more concentrated during the peak periods than under the reference scenario. Residential peak consumption occurs on average in the evenings between 6 and 9 PM (Figure 47). In contrast with the reference scenario, peak residential consumption is well correlated with peak prices in the

[87] The rates are slightly different when assuming that all PV customers are compensated with the hourly netting scheme; the peak rate and off-peak rates in the high-priced season are 1% higher and 1% lower, respectively, than under net metering. Although the volumetric adder is slightly lower for hourly netting than for net metering, as the average cost of behind-the-meter generation to be recovered through the rate is higher under net metering, more electricity needs to be purchased on the wholesale market during the peak period under hourly netting, and this small amount of electricity purchased is much more expensive than the retail rate, driving the peak rate up slightly.

33% RE mix scenario; the correlation coefficient between average residential demand (net of behind-the-meter PV) and average wholesale prices in high-season business days is 0.68, whereas it is 0.44 for the reference scenario.[88] Even though the peak TOU period in the high season is found to be only 3 hours in length (vs. 6 hours in the reference scenario), 6.1% of annual residential load occurs in this period (or 2.0% per peak hour vs. 1.4% per peak hour in the reference scenario). Almost 19% of the total annual residential bill is attributable to consumption during the high season's peak period under the 33% RE mix scenario (Table 19).

Table 19: Annual residential load and electricity bill by TOU period. (Numbers do not sum to 100% due to rounding)

	Annual residential load within TOU period			Annual residential bill within TOU period		
	Low Period	**Mid Period**	**Peak Period**	**Low Period**	**Mid Period**	**Peak Period**
High Season	18.7%	12.3%	6.1%	15.6%	11.9%	18.9%
Low Season	18.3%	30.4%	14.1%	15.2%	25.7%	12.7%

Whereas there is higher coincidence between times of highest residential load and peak price periods, there is very little coincidence between PV generation and peak periods in the 33% RE mix scenario. Less than 2% of annual PV generation occurs during the high season's peak period (vs. 8.4% in the reference scenario). This results in 6.4% of annual compensation from PV, assuming full net metering, during the high season's peak period.

Table 20: Annual PV generation and compensation (with net metering) by TOU period, for the 33% RE mix scenario

	Annual PV generation within TOU period			Annual PV compensation within TOU period		
	Low Period	**Mid Period**	**Peak Period**	**Low Period**	**Mid Period**	**Peak Period**
High Season	24.8%	13.6%	1.9%	23.1%	14.6%	6.4%
Low Season	17.0%	39.0%	3.6%	15.6%	36.9%	3.5%

iii. Real-time-pricing rate

The hourly varying RTP retail rate for residential customers tracks the wholesale price profile for the 33% RE mix scenario. The average rate for residential customers with RTP is

[88] If we focus on the 12 hours of highest residential demand, 12 noon to 12 midnight, for business days in the high-priced season, the correlation coefficient stays high (r = 0.69) for the RE mix scenario but is small (r = 0.15) for the reference scenario.

$0.192/kWh with net metering,[89] which is 7% higher than under the reference scenario. The average price paid for electricity in the wholesale market is $0.098/kWh, or 4% higher than for the reference scenario. The residual revenue adder is $0.094/kWh,[90] or 10% higher than for the reference scenario. This increase reflects the net effect of a number of countervailing factors, including the additional cost of RE purchases, a higher coincidence of residential load and wholesale prices, and reduced net sales from which revenues need to be recovered. The average price profile in the peak season tends to peak later, into early evening, compared with the reference case, due to the large levels of zero-marginal-cost PV generation in the afternoon.

About 2.2% of annual residential load occurs during the more expensive hours when wholesale prices are greater than $0.10/kWh (compared to 1.7% under the reference scenario). This contributes to 26.7% of total annual costs, mostly due to the hours when scarcity pricing is reached in the wholesale market (Table 21).[91]

Table 21: Annual residential load and cost by wholesale electricity price bin

Wholesale price ($/kWh)	Annual price distribution (%)	Annual residential load (%)	Annual residential cost (%)
0-0.05	58.4%	48.3%	34.3%
0.05-0.1	40.5%	49.5%	39.0%
0.1-10	1.1%	2.2%	26.7%

The median compensation for PV with RTP under the 33% RE mix scenario, with net metering, is $0.156/kWh. As opposed to the reference scenario, a relatively small proportion (under 10%) of the annual PV compensation is derived from the more expensive hours, when prices are greater than $0.10/kWh in the wholesale market. Over 70% of PV generation occurs during hours with wholesale prices under $0.05/kWh, resulting in over 60% of annual PV compensation, with net metering (Table 22). This represents a significantly greater percentage than under the reference scenario, where only 15% of annual PV generation occurs during hours with wholesale prices under $0.05/kWh, which results in about 11% of annual PV compensation. Hourly wholesale electricity prices are generally below average at times when PV generates electricity because significant solar generation during the afternoon shifts the time of peak "net" load (system load minus PV generation) into the evening hours. Although the correlation is weak between PV generation and wholesale prices ($r = -0.04$), PV generation is a strong predictor of a price decrease from the reference scenario to the 33% RE mix scenario ($r = -0.55$ when correlating direction in price change and PV generation).

[89] The average rate is $0.191/kWh with hourly netting, or 7% higher than with the reference scenario.
[90] The residual revenue adder is $0.093/kWh with hourly netting, or 9% higher than with the reference scenario.
[91] Customers could mitigate the bill impact of these high-priced hours if we assume price elasticity, a scenario presented in Section 4.3.5.

Table 22: Annual residential PV generation and compensation (with net metering) by wholesale electricity price bin for mean customer PV generation profile, under the 33% renewable mix scenario

Wholesale price ($/kWh)	Annual PV generation (%)	Annual PV compensation (%)
0-0.05	71.7%	63.4%
0.05-0.1	27.6%	27.2%
0.1-10	0.7%	9.4%

4.3.4.2 Value of bill savings relative to reference scenario

In this section, I quantify how the value of bill savings of each of the rates and compensation mechanisms under the 33% RE mix scenario compares with the corresponding rate, compensation mechanism, and PV-to-load ratio under the reference scenario. These results are summarized in Figure 48.

Compared with the reference scenario, the value of bill savings from PV for customers with the flat rate and net metering under the 33% RE mix scenario increases by about 7% for all PV-to-load ratios. This increase is principally due to an increased volumetric charge, R_{adder}, from the increased renewable acquisition costs. Customers with the TOU rate and net metering receive 14% lower value of bill savings under the 33% RE mix scenario than under the reference scenario, due to the lower rates during times of PV generation[92]. The higher solar penetration drives down wholesale prices during periods of high solar generation, which leads to lower wholesale value flowing through as lower retail rates and hence lower bill savings. Similarly to customers with the TOU rate, customers with the RTP rate and net metering receive 16% lower value of bill savings under the 33% RE mix scenario than under the reference scenario. Again, since all PV generation is compensated at the same rate regardless of whether it displaces consumption or is exported to the grid, the size of the PV system does not impact the relative value of bill savings from PV generation when net metering is offered.

[92] The lower wholesale rates at times when PV generates leads to a shift in the peak TOU period, and the lower bill savings is a result of the lower PV generation-weighted average TOU rate.

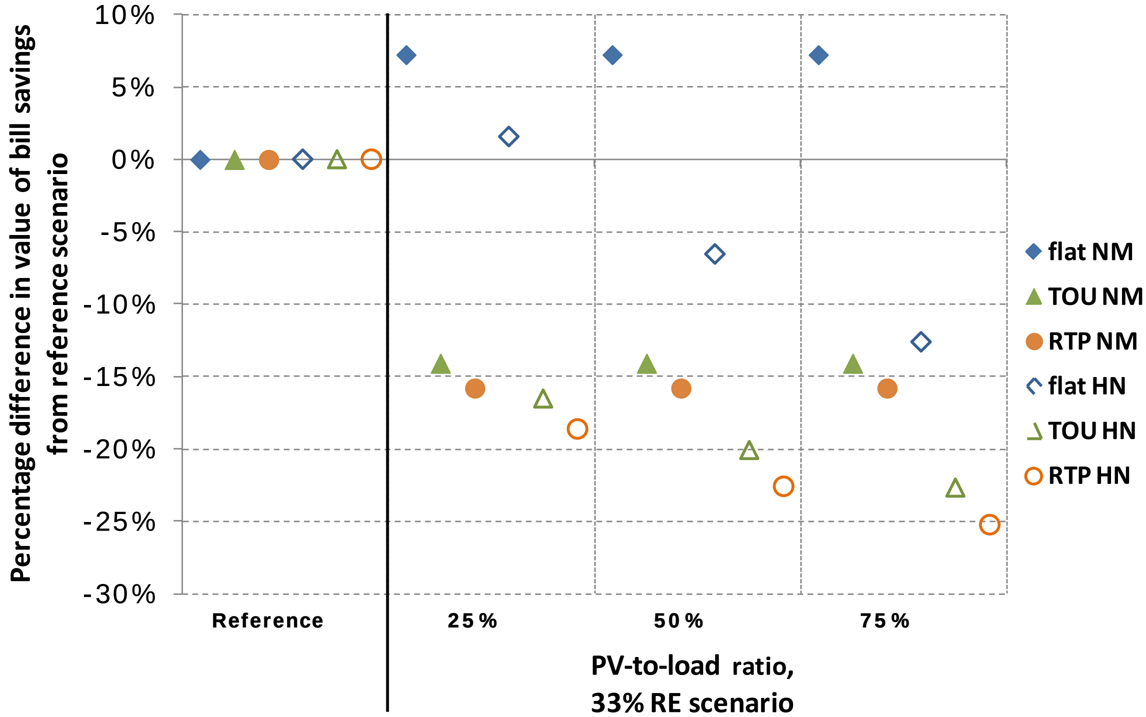

Figure 48. Comparing value of bill savings between reference and 33% RE mix scenarios

With hourly netting, the value of bill savings decreases with increasing PV-to-load ratio, for any of the retail rate options. The median value of bill savings for the flat rate with hourly netting is 2% greater under the 33% RE mix scenario than for the flat rate and hourly netting under the reference scenario, assuming a 25% PV-to-load ratio (Figure 48). As the PV-to-load ratio increases to 50% and 75%, however, an increasing percentage of the PV generation is compensated at the wholesale price. Given that the wholesale price during periods of PV generation in the 33% RE mix scenario is considerably lower than in the reference scenario, the value of bill savings are 7% and 13% lower, respectively, than the flat rate and hourly netting under the reference scenario. Similarly, I observe a drop in value of bill savings with the TOU rate and hourly netting under the 33% RE mix scenario, from 17% less to 23% less than under the reference scenario for customers in the sample with a 25% and 75% PV-to-load ratio, respectively. This erosion in bill savings for 25% and 75% PV-to-load ratio climbs to 19% and 25% below the reference scenario for customers with RTP and hourly netting. These declines in comparison to the reference scenario again reflect the comparatively low wholesale prices in hours with PV generation in the 33% RE mix scenario.

4.3.4.3 Value of bill savings relative to flat rate

Section 4.3.4.1 suggests a weak or negative correlation between PV generation and wholesale electricity prices under the 33% RE mix scenario. The hourly wholesale electricity prices are generally lower than average when PV generates electricity because significant solar generation during the afternoon shifts the time of peak “net” load (system load minus PV generation) into the evening hours. Consequently, the more dependent rates are on wholesale market prices, the lower the value of bill savings from PV under this scenario. The flat rate is not time dependent and is the least correlated with market prices, thus it leads to the highest value of bill savings from PV of the three retail rates considered in this study. The rate most correlated with wholesale market prices is RTP, which leads to the lowest value of bill savings from PV. The value of bill savings from PV for the flat, TOU, and RTP rates for net metering and hourly netting, relative to that of the flat rate with net metering, is shown in Figure 49 for the 33% RE mix scenario. The median *decrease* in bill savings from the flat rate with net metering is found to be 10% and 21% for TOU and RTP with net metering, respectively. This is in sharp contrast to the *increase* in value of bill savings brought by changing from the flat rate to the TOU and RTP rate under the reference scenario, as noted in Section 4.3.1.2. As with the reference scenario, PV system size does not impact the median value of bill savings from PV when compensated with net metering, since electricity generated from PV is compensated at the same rate regardless of generation levels. The range in value of bill savings across customers within the sample with the flat rate is zero, as all electricity generated is compensated at exactly the same rate. Even with TOU and RTP, the spread in value of bill savings from PV is small for customers in the sample. The spread is slightly greater with RTP than with TOU rates, as there is greater variation in hourly insolation than insolation by TOU period.[93]

The erosion in bill savings associated with moving from net metering to hourly netting is much greater under the 33% RE mix scenario than the reference scenario because of the lower wholesale prices applicable to hourly excess PV generation. As shown in Figure 49, the median value of bill savings for customers with the flat rate and hourly netting is 43% lower than with the flat rate and net metering, assuming a 75% PV-to-load ratio. The erosion in median value of bill savings increases to 45% and 48% for the TOU and RTP rates, respectively. The difference in value of bill savings between the three retail rate options is smaller with hourly netting than with net metering, since the excess hourly generation is compensated at the same rate for all three rate options; only the portion of generation that displaces consumption within each hour is compensated at different rates. As with the reference scenario, the decay in value of bill savings is significantly reduced for smaller PV systems, as less PV generation is compensated at wholesale electricity rates. With a 50% PV-to-load ratio, the median values of bill savings for the flat, TOU, and RTP rates with hourly netting are 34%, 38%, and 42% lower than for the flat rate with net metering, respectively. The corresponding declines are 17%, 23%, and 31% for customers in the sample with a 25% PV-to-load ratio.

[93] The spread in total annual insolation per m^2 for customers in our sample does not directly impact the range in value from bill savings, since all systems are sized to meet 25%, 50%, or 75% of total annual load. The percent of total PV generation in each TOU period (or hour for RTP rates) determines the value of bill savings under net metering, and this leads to a relatively low range in value of bill savings for customers in our sample. The distribution of values with TOU and RTP under net metering is uneven due to the uneven geographical distribution of customers. The distribution for customers under hourly netting is more regular, as this spread is additionally driven by the differences in the profiles of hourly excess PV generation, which is relatively even in our sample.

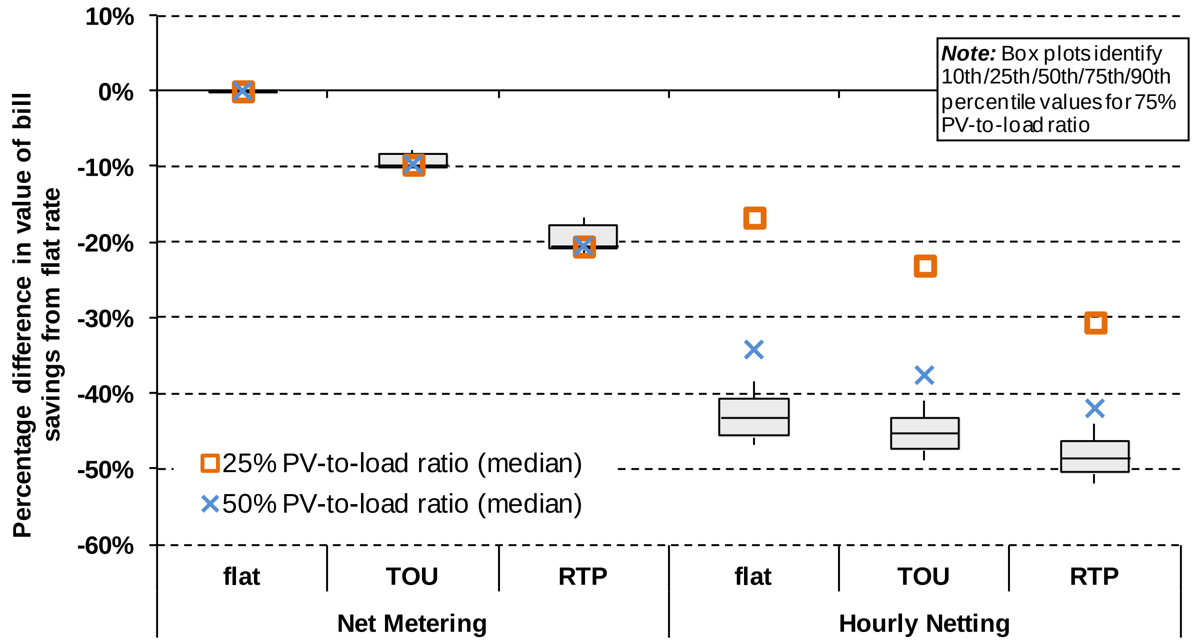

Figure 49: Relative value of bill savings from PV for flat, TOU, and RTP rates, for net metering and hourly netting, for the 33% RE mix scenario

4.3.5 33% RE integration scenarios

Results from the previous section indicate decreasing value from PV for customers under net metering with TOU or RTP and for customers under hourly netting for all rates, under the 33% RE mix scenario. This decrease in value is due to the high levels of renewables, particularly solar, which drive down wholesale prices during sunny periods. In turn, this erodes the bill savings from rates that are impacted by the temporal profile of wholesale electricity prices. This section explores three methods that could mitigate this potential decline in value from bill savings. The magnitude of change in value of bill savings when compared to the core 33% RE mix scenario is different for each retail rate and compensation mechanism considered, although each of these scenarios positively impacts the value of bill savings, except for those customers with the flat rate and net metering.

In the high-storage scenario, 6.33 GW of pumped hydro storage is "forced" into the system, in addition to the existing 3.56 GW of pumped hydro currently in California.[94] The capital costs, levelized over the lifetime of the storage, are recovered in the retail rates through the volumetric adder, R_{adder}, which increases by \$0.013/kWh over that of the 33% RE mix scenario. The addition of storage to the generation mix increases wholesale prices in off-peak periods and reduces peak prices, although the times at which wholesale prices peak and fall are similar to the times in the 33% RE mix scenario.

---

[94] The additional 6.33 GW is the sum of all proposed pumped hydro projects in California, as of November 2010, as per NHA (2010).

The introduction of higher levels of grid storage impacts rate and PV compensation options similarly. The flat rate increases by $0.011/kWh (or 5.6%) over the 33% RE mix scenario, principally due to the increased costs recovered through the volumetric adder, R_{adder}, which increases by $0.013/kWh. This leads to a corresponding increase in value of bill savings of 6% for PV customers with the flat rate and net metering and a median increase of 7% for customers with the flat rate and hourly netting, both at a 75% PV-to-load ratio (Figure 50). For the TOU rate, the peak, mid-peak, and off-peak period definitions do not change significantly, although the rates within each of the periods do change. The peak rate in the high-priced season decreases by $0.155/kWh (or 27%) from the 33% RE mix scenario, whereas all mid-peak and low period rates increase by 6%-12%. Since roughly 95% of electricity generated from PV occurs during the low and mid-peak priced periods in the 33% renewable energy mix scenario, the median value of bill savings increases by 8% under the TOU rate with net metering. The increase in value of bill savings for the TOU rate and hourly netting is 6% in comparison to the core 33% scenario, as the average wholesale electricity price is lower than the average TOU rate for the excess hourly PV generation (assuming a 75% PV-to-load ratio). Similarly to the TOU rate, PV generation is compensated at higher RTP rates, on average, under the high-storage scenario than under the 33% RE mix scenario. Again, this is because, with high levels of renewable and solar energy, customer-sited PV generation typically produces electricity when wholesale prices are comparatively low, and increased storage leads to reduced peak prices and increased off-peak prices, thereby boosting the value of solar generation at high penetrations. The median value of bill savings for customers with RTP and net metering in the sample is 12% greater under the high-storage scenario than under the 33% RE mix scenario. The corresponding increase for customers with RTP and hourly netting is 10%.

A second integration scenario—the demand response scenario—includes a simulated system-wide price elasticity of demand. The price elasticity of demand is set at -0.1 (i.e., a 10% decrease in demand for a doubling in wholesale price). This results in lower wholesale price peaks, since price-sensitive customers reduce their demand during hours with higher prices, preventing very steep price spikes.

With an elasticity of demand of -0.1, the flat rate is $0.181/kWh, or 6% lower than for the original 33% RE mix scenario.[95] This reduction is due to the reduced average cost of electricity purchased on the wholesale market as a result of lower peak prices during peak residential demand. This reduction in the flat rate also implies a reduction in the value of bill savings from PV with net metering, since all PV generation is compensated at the flat rate. With hourly netting, there are two opposing factors; the PV generation that displaces consumption within the hour is compensated at the lower flat retail rate, while excess hourly PV generation is compensated at a higher wholesale rate on average. For customers with a 75% PV-to-load ratio, this results in a median 3% net increase in value of bill savings (Figure 50), but for customers with smaller systems, a greater proportion of PV generation is compensated at the retail rate, and hence the value of bill savings is lower. Customers with the TOU rate and net metering have a small increase in value of bill savings (3%) as compared with the 33% RE mix scenario, as the

[95] We assume that all mechanisms and technologies that enable demand response do not add costs to be recovered by utilities and hence do not impact the volumetric adder, R_{adder}. Additional hardware and communication costs would increase the adder and could offset the reduction in average costs for electricity acquired on the wholesale market, thus increasing the value of bill savings for all rate options.

increase in wholesale prices during hours of PV generation increases the average rate in those hours. The averaging of wholesale prices over the TOU periods reduces the value of PV generation relative to compensation at the wholesale price. This leads to a greater increase in value of bill savings from PV with hourly netting than with net metering (i.e., a 6% increase over the 33% RE mix scenario). Customers with the RTP rate benefit the most from a system-level elasticity of demand of -0.1. With both net metering and hourly netting, the value of bill savings from PV increases by 10% over the 33% renewable mix for customers with RTP.[96]

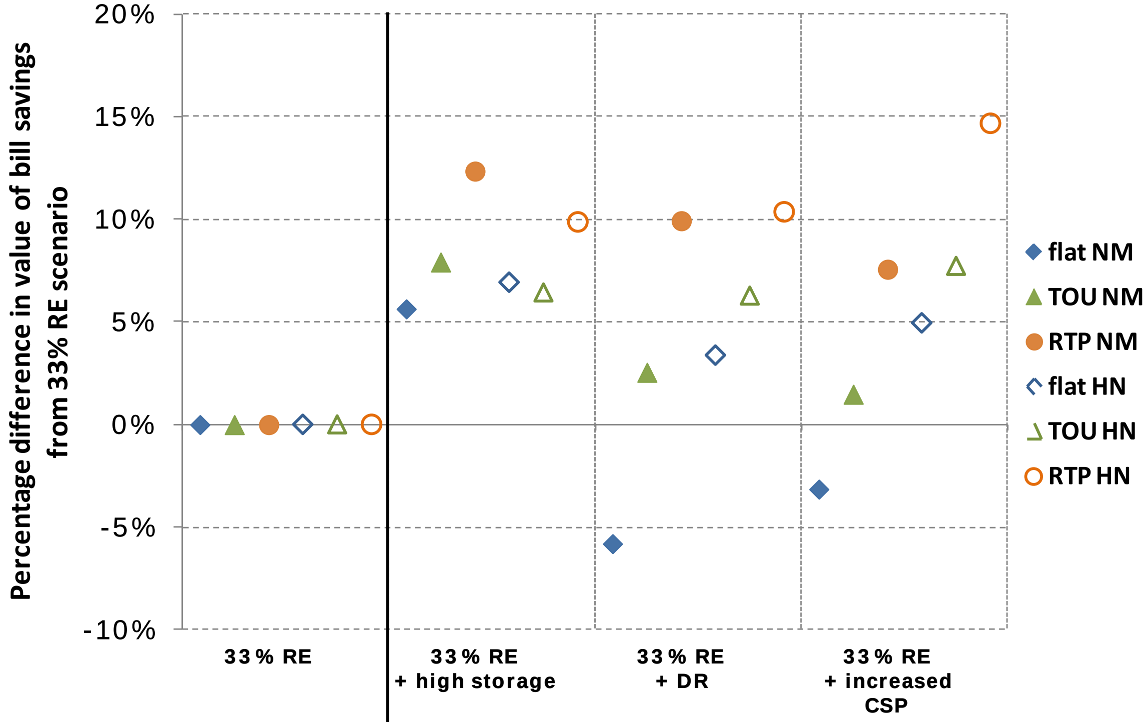

Figure 50: Change in value of bill savings from 33% RE to 33% RE integration scenarios, assuming a 75% PV-to-load ratio

The final variation on the 33% RE mix scenario considered here has increased levels of utility-scale CSP with 6-hour storage capacity (the PV penetration is reduced to maintain a total renewable penetration of 33%; see section 4.2.1 for scenario details). Compared with the core 33% RE mix scenario, the wholesale price profile resulting from increased CSP penetration peaks slightly earlier in the day. Some of the CSP power generation is stored, and hence prices during hours of peak insolation are not as low as for the 33% RE mix scenario; the stored energy is released during peak times, which slightly reduces prices during those periods. This shift, along with decreased need for wholesale market purchases because of increased CSP, results in a lower average cost for electricity purchased on the wholesale market to meet residential demand, which is in addition to the smaller, countervailing effect on the volumetric adder of higher costs

[96] Note that this does not imply that the value of bill savings from PV with hourly netting is the same than with net metering—it is not—but rather the increase in value over the same rate type from the 33% RE mix scenario is about equal for RTP with hourly netting and with net metering.

of CSP. The consequent flat rate is slightly lower than for the 33% RE mix scenario; the flat rate and value of bill savings with the flat rate and net metering decrease by 3% compared with the core 33% RE mix scenario. The value of bill savings is only slightly higher than under the 33% RE mix scenario for customers under the TOU rate and net metering, whereas the increase in value of bill savings from PV with the RTP rate and net metering is 8%. As with all integration scenarios, the *increase* relative to the 33% RE mix scenario is greater for customers under RTP than those under TOU, although the value of bill savings with the TOU rate is still greater than the value with RTP (see Figure 49).

Since the wholesale prices during times of greater insolation are higher, the value of bill savings from PV with all rate options and hourly netting is higher with the high CSP scenario than the corresponding rate option with the core 33% RE mix scenario, assuming a PV-to-load ratio of 75%. Customers with a flat rate and hourly netting see a 5% increase. With the TOU rate, the increase in value of bill savings from PV is 8% over the 33% RE mix scenario, again due to the higher wholesale prices during times of PV generation. The increase is close to 15% for RTP with hourly netting, as RTP is most closely correlated with wholesale price.

4.3.6 Results summary

This section presents the value of bill savings for all rate options, compensation schemes, and scenarios considered in the chapter's central analysis, relative to the median value of bill savings for the flat rate with net metering in the reference scenario. These are compiled in Figure 51, for customers with a 75% PV-to-load ratio.

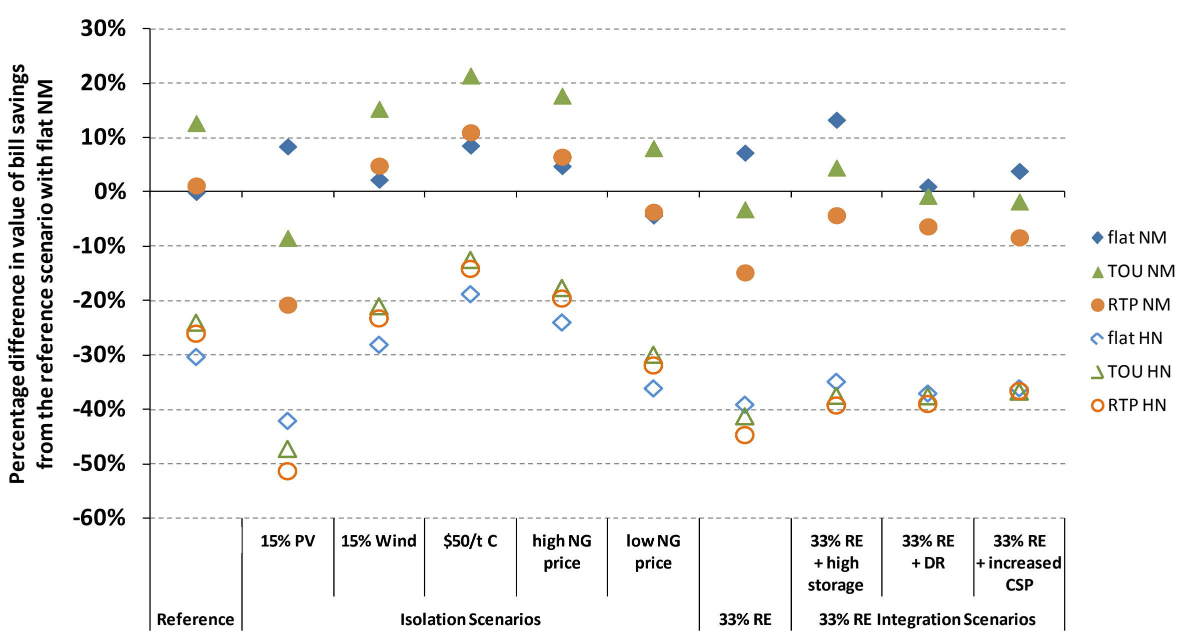

Figure 51: Median value of bill savings from PV for flat, TOU, and RTP rates, for net metering and hourly netting, for all scenarios, relative to the reference scenario with flat rate with net metering. 75% PV-to-load ratio assumed

I note a few general trends from the summary figure.

1) Relative to the reference scenario with a flat rate and net metering, in most other scenarios the flat rate with net metering increases the value of bill savings from residential PV by 1%-13%. The only exception is the isolation scenario with a low natural gas price, which has a lower flat rate due to a decrease in the average cost of electricity acquired on the wholesale market to serve residential load (3% lower than for net metering, flat rate, under the reference scenario).
2) Hourly netting erodes the value of bill savings by 23%-47%, relative to net metering, depending on the scenario and rate option, at a 75% PV-to-load ratio.
3) For all scenarios without increased solar penetration, the rate option that provides the greatest value to a residential PV system owner is the TOU rate, followed by the RTP rate, followed by the flat rate.
4) In stark contrast, for all scenarios with high solar penetration, the flat rate provides the most value from PV, followed by the TOU rate, followed by RTP, for a given compensation scheme.
5) Customers under the RTP rate with hourly netting in the 15% PV scenario receive the lowest value of bill savings of all rates, compensation schemes, and scenarios considered (51% lower than that of customers under the flat rate with net metering in the reference scenario). Conversely, customers under the TOU rate with net metering in the high carbon price scenario receive the highest value from PV (in the median case, 21% higher than that of customers under the flat rate with net metering in the reference scenario).

4.4 Results: Alternative wholesale market design and retail rate structures (Side analyses)

A number of assumptions have been made regarding the retail rate structures considered in the central analysis results presented thus far. As mentioned previously, these represent the middle of the spectrum in terms of efficiency: the rates are based on wholesale prices which recover capacity costs (efficiently) in the hours where capacity is constrained (through the energy-only market design), but the fixed costs are recovered (inefficiently) through volumetric charges, as they are in many utilities today. In addition, the flat rate is implemented in this analysis *without* increasing block pricing, in contrast to how it is today in California's three largest IOUs. In this section, I will consider alternative rate structures: (a) retail rates based on an electricity market with a price cap of $1000/MWh (as is the case currently in CA) and which recovers capacity costs ensuring the same level of resource adequacy by adding a volumetric charge to each kWh of electricity sold, in section 4.4.1; and, (b) retail rates where the fixed costs are recovered through a two-part tariff consisting of an energy charge and a fixed customer charge, also quantifying the impact of a multi-level customer charge on value of bill savings (as proposed in Friedman (2012)), in section 4.4.2; and, (c) a flat rate with increasing block pricing, in section 4.4.3. Each of these rates is considered only for a subset of the wholesale electricity market scenarios and rate options, and the methodology for constructing these rates are reviewed in section 4.2.5

4.4.1 Lower wholesale electricity price cap and volumetric capacity charge

In this side analysis with a lower wholesale electricity price cap, price spikes are limited to $1,000/kWh (versus $10,000/MWh with the energy-only market in the central analysis), though the *number* of peaks doesn't change. The rates are designed such that in both cases, with and without an energy only market, the same revenue levels are collected to ensure to recover sufficient costs to maintain the same level of resource adequacy. With a lower cap, this is done by way of a parallel capacity market. As explained in section 4.2.5.1, the costs of ensuring sufficient capacity are recovered through a flat volumetric charge, which is added to the retail rate for residential customers. The capacity cost adder ranges from \$0.019/kWh to \$0.020/kWh, depending on the scenario and the PV compensation mechanism assumed.

As shown in equation (15), in section 4.2.5.1, the flat rate is no different in the energy-only market or with the low price cap and parallel capacity market. This implies that the values of bill savings from PV are equal in both these cases. The value of bill savings for the flat rate with net metering is equal to \$0.179/kWh (as for the base case with a higher wholesale price cap). Figure 52 shows the value of bill savings from PV under each of the rate options for the reference scenario and the renewable electricity mix scenario, relative to the flat rate with net metering in the reference scenario; also on this figure are results from the energy-only market and the lower price cap with the capacity cost adder, assuming a 75% PV-to-load ratio.

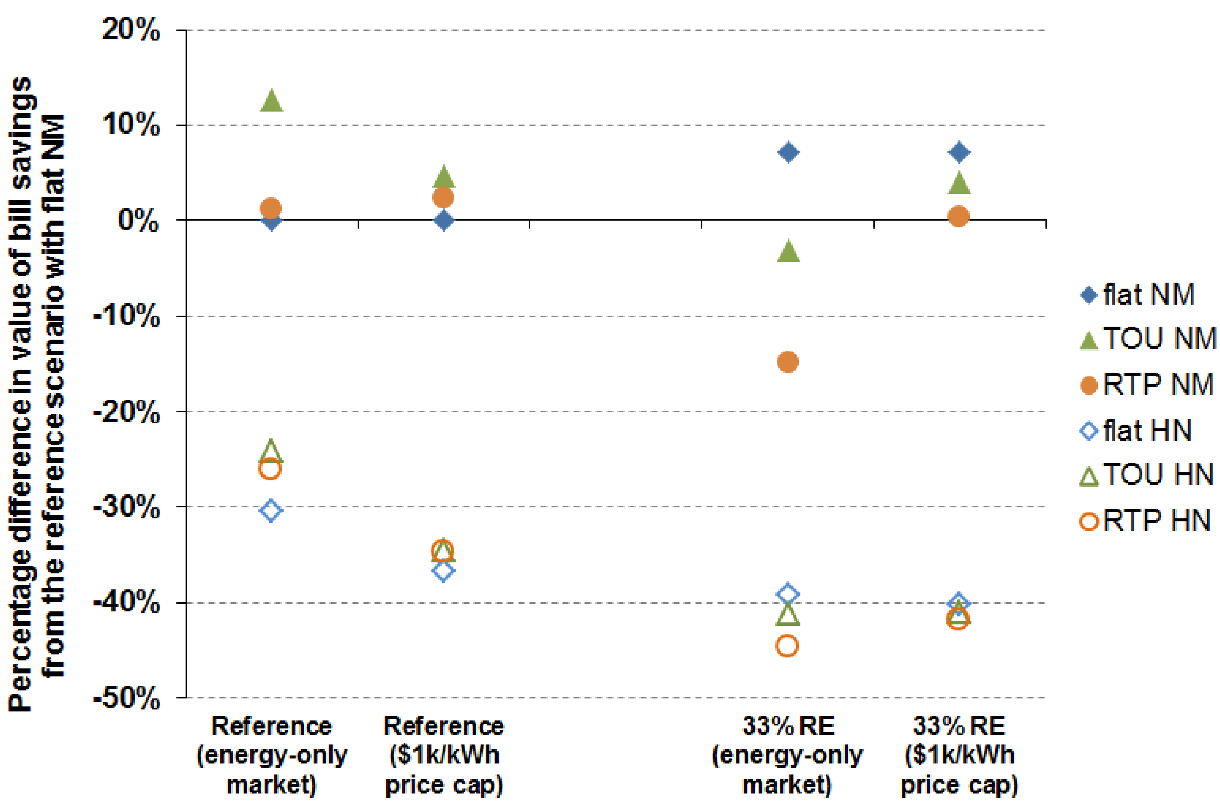

Figure 52: Value of bill savings for the reference scenario and the 33% renewables mix scenario, relative to the reference scenario's flat rate with net metering, assuming an energy only market and a lower price cap with a capacity cost adder. 75% PV-to-load ratio assumed.

For the reference scenario under the low price cap, the bill savings from PV for customers under the TOU rate with net metering is 4.6% higher than under the flat rate with net metering. As with the energy-only market, this increase in bill savings is due to the coincidence between the higher priced TOU periods and PV generation; the peak TOU period in the high priced season is 1 to 7 pm during business days (see Appendix X for retail rate and period definitions).

However, this increase in value of bill savings, relative to the flat rate, is lower than for the central analysis with the energy-only market (12.7%); although the peak period in the high priced season is defined similarly to that with the energy-only model, the peak rate is almost half the level ($0.283/kWh vs. $0.493/kWh for low price cap and energy-only model, respectively). The capacity cost adder is added to all hours, raising the rate in all other hours by $0.02/kWh, which also increases the value of bill savings with the low price cap. For the RTP rate with net metering, the value of bill savings from PV with a lower price cap is similar to that with the energy-only model, even though the rates during the peak hours are lower due to the low price cap. Again here, the effect of the $0.02/kWh capacity cost adder in all hours counters the decrease in the peak period rate.

With hourly netting under the reference scenario, there is a considerable decrease in the value of bill savings for all rates with the low price cap and capacity cost adder. Again, when compared with net metering, the decrease in value of net metering is due to low wholesale price compensation levels of hourly net excess PV generation. Since the average wholesale price of net excess PV generation is significantly lower than the retail rate, the average value of bill savings is lower for hourly netting. As seen in Figure 52, with hourly netting, the value is even lower than in the central analysis (with the energy-only model) due to the lower price cap and the reduction in average hourly wholesale prices of the customers' hourly net excess PV generation.

For the 33% RE mix scenario, the value of bill savings with net metering is again the same for the flat rate regardless of the wholesale price cap level. Both time varying rates with net metering lead to higher bill savings from PV. The dramatic decrease in value that was observed with the increased PV penetration of the 33% RE mix scenario (in the central analysis with the energy-only model) is not present with the lower price cap (see Figure 53), even though peak prices still shift to later in the day. This counter-intuitive result is due to the volumetric adder being a higher proportion of the total retail rate, with the lower price cap. The portion of the rate that recovers the wholesale market purchases, R_{gen}, does decrease significantly (by 48%) due to the shifting of the peak prices, but R_{gen} only represents less than 30% of the total rate, and the decrease in R_{gen} is countered by the increase in R_{adder} due to increased renewable electricity purchases, resulting in a similar rate under the reference and 33% renewables mix scenario. This explains why the TOU and RTP rate only erode by 1% and 2%, respectively, when compared with the reference scenario.

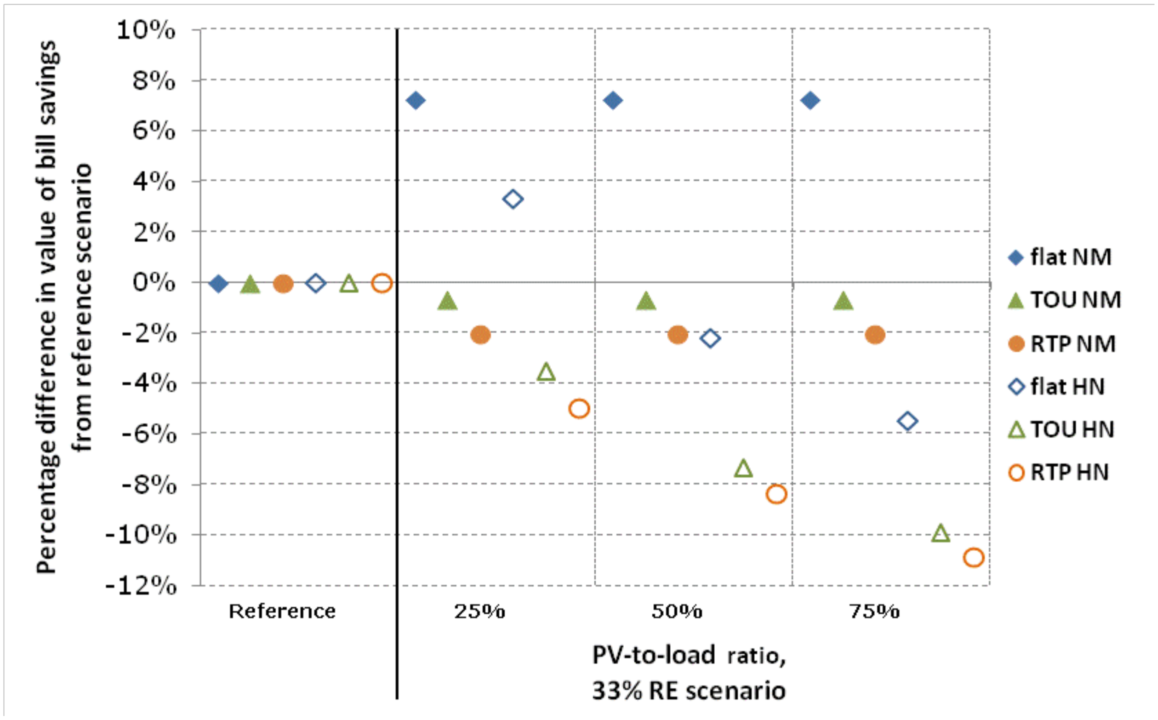

Figure 53. Comparing value of bill savings between reference and 33% RE mix scenarios, assuming a lower wholesale price cap and a capacity cost adder

As with the reference case, the value of bill savings from PV under hourly netting with the 33% renewables scenario is lower than with the reference scenario, as seen in Figure 53, for higher PV-to-load ratios. As expected, when PV-to-load ratios increase, the value of bill savings decrease with hourly netting, as a greater percentage of PV generation is hourly excess and is hence compensated at the low wholesale prices. At 50% and 75% PV-to-load ratios, the only rate that leads to higher bill savings is the flat rate, when compared with the reference case (similar to the rates with a higher wholesale price cap).

4.4.2 Two-part tariffs

In this section, I consider a potential alternative rate structure to ones considered in the central analysis: the two-part tariff. As explained in section 4.2.5.2, two part tariffs include a customer charge (that does not vary with electricity load and by which utilities' fixed costs are recovered) and a volumetric charge (by which the utilities' variable costs are recovered). In most cases, customer charges are fixed and hence cannot be displaced by PV generation with net metering, having significant implications for the value of bill savings from PV. I also consider the implications of a customer charge which can be reduced by PV generation, as suggested by Friedman (2012).

Most importantly, for rates with a fixed customer charge, the value of bill savings from PV is greatly reduced when compared with rates without customer charges, recovering all costs with volumetric charges. The extent of the erosion in bill savings from PV can be seen in Figure 54; under net metering the bill savings decrease by 52%-53%, and under hourly netting the bill savings decrease by 33%-36%. The decrease under hourly netting is less significant than for net metering, since a smaller proportion of PV generation is compensated at the full retail rate than with net metering; however, the magnitudes of the values under hourly netting are lower in both cases. There are no large variations in the decrease in bill savings from PV from one rate option to the next, as each of the rates considered are impacted similarly; utilities recover the same amount for fixed costs via a customer charge for both time invariant rates (e.g. flat rate) and time-varying rates (e.g. TOU rate).

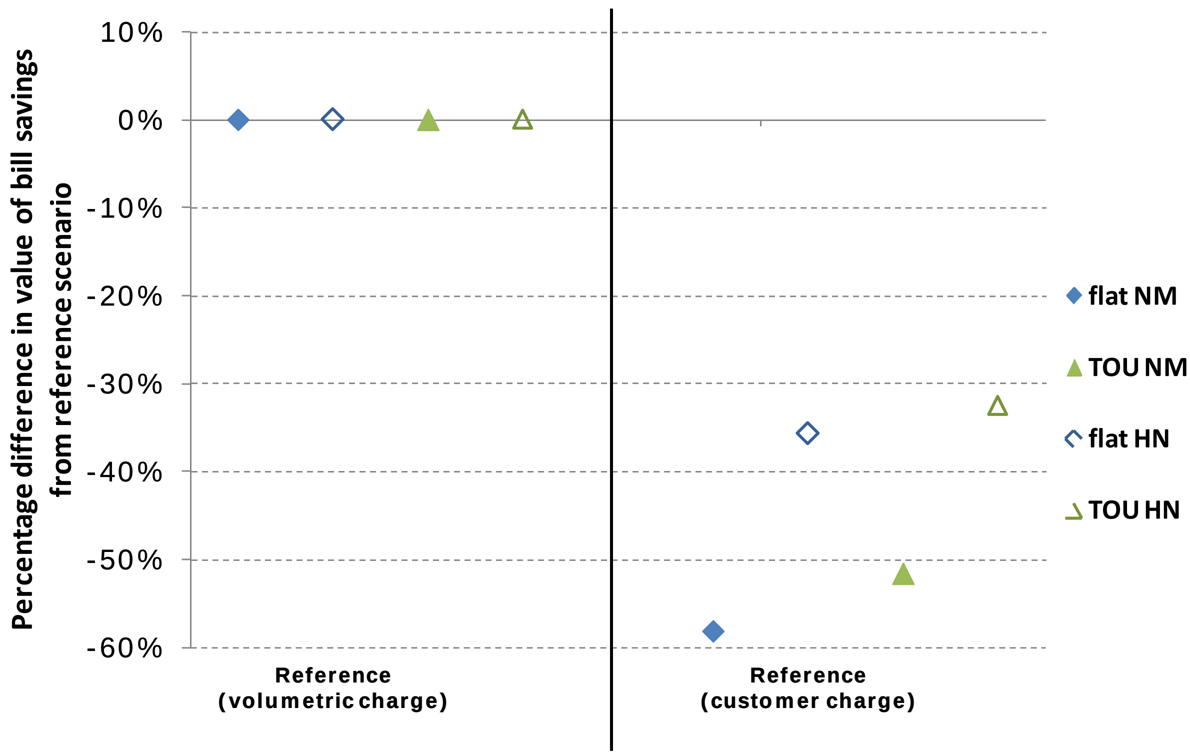

Figure 54. Bill savings for the reference scenario assuming a two-part tariff structure, relative to the same rate option with the reference scenario assuming volumetric rates.

Note: **As explained in the section 4.2.5, on page 99, the RTP rate designed with a two part tariff structure is dissimilar to the RTP rate with volumetric charges only, and hence is not compared directly in this figure.**

Within the reference case, assuming a two-part tariff, the TOU rate with net metering provides the greatest value, as can be seen in Figure 55. This is due to the good coincidence between the TOU's peak periods and the hours when the sun shines, allowing PV generation to be compensated at the higher rates. The bill savings from PV are only slightly lower with hourly netting, because the average wholesale price of customers' exported electricity is only slightly less than the average TOU rate. The significant decline in value observed with volumetric rates was due to the wholesale price being much lower than the retail rate. Since there is no fixed cost related volumetric adder with two-part tariff, the erosion in value resulting from a move away from net metering to hourly netting is much less significant. With the RTP rate[97], similar to the TOU rate, the value is almost as high as the TOU rate, 28% higher than the flat rate with net metering.[98] The lowest value rate for the reference scenario is the flat rate with net metering. The flat rate with hourly netting leads to a higher value, as the average wholesale price during times of hourly excess generation is higher than the flat rate.

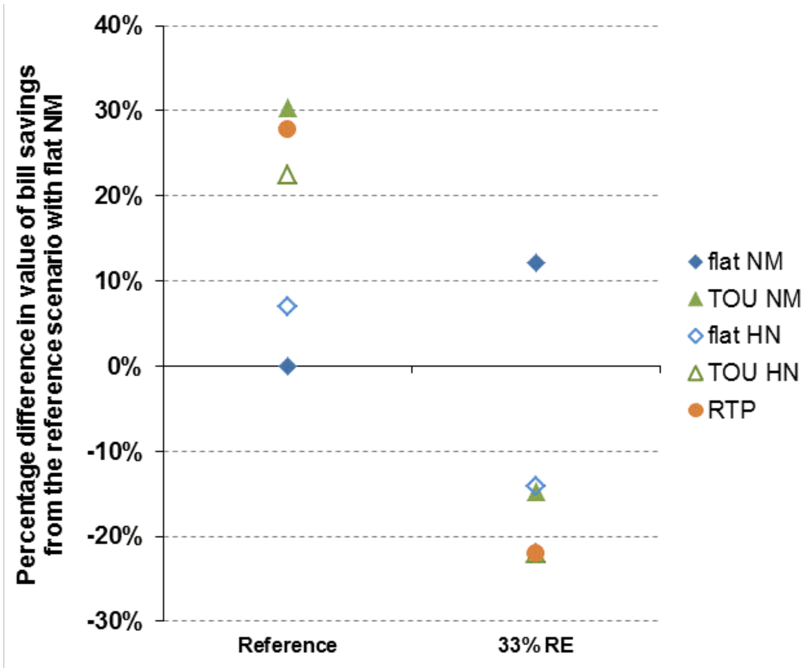

Figure 55. Value of bill savings for the reference scenario assuming a two-part tariff structure, relative to the flat rate with net metering.

Under the 33% renewables scenario, all rates except for the flat rate with net metering lead to a lower value of bill savings than the flat rate with net metering under the reference scenario, as seen in Figure 55. Under the 33% renewables scenario, the flat rate with net metering results in the highest bill savings, of the rate options considered with two-part tariffs. All other rates lead to erosion in bill savings resulting from lower wholesale prices when PV generates – a result of the scenario's high PV penetration. RTP is impacted the most, whereas averaging over the TOU periods benefits PV generation slightly. Customers with hourly netting and the flat or TOU rates would receive a lower value of bill savings than those with net metering, due to the portion of the generation compensated at the low wholesale price instead of at the retail rate with net metering. Hourly netting leads to a sharper decline in value, relative to net metering, for customers with the flat rate than those with the TOU rate. This is due to the TOU rate already being low during

[97] As explained in section 4.2.5.2, the RTP is defined in this case to be the wholesale price each hour plus a customer charge *without* a volumetric adder to recover variable costs other than wholesale electricity purchases.
[98] At first impression, it may seem surprising that the rate is so much higher than in the flat rate, considering it was almost the same to the flat rate in the base case with volumetric charges. This is mainly because the total residential revenue from the volumetric portion of the RTP rate (assuming all customers were on RTP rates) happens to be greater than the total revenue from the volumetric portion of the flat rate (where all customers on the flat rate). This is due to the way that the RTP rate is defined with these assumptions; the volumetric portion of the RTP rate is always equal to the wholesale price and does not depend on the utilities' fixed/variable cost recovery (as do all other rates here).

hours of net excess PV generation. Since the price difference for this net excess PV generation is greater for the flat rate than for the TOU rate, the decrease in value is greater for the flat rate than the TOU rate, under hourly netting. Customers with the RTP rate receive among the lowest values from bill savings from PV, as the RTP rate is equal to the hourly wholesale electricity price, which is the most negatively correlated to the levels of PV generation.

The analysis presented above assumes that PV customers cannot displace any of their fixed customer charges. The severe erosion in bill savings associated with moving towards such a two-part tariff rate structure from a completely volumetric rate would be very problematic for PV advocates and customers, particularly those who invested prior to the introduction of the two-part tariffs on the expectation that rates would remain entirely volumetric charges and because of the argument that PV may add some value to the utility, such as environmental benefits, reduced line losses, or displaced transmission and distribution capacity. One potential solution to this issue would be to have fixed customer charges that can be reduced when a customer makes a major change to their electricity consumption, such as the addition of a PV system. For example, Friedman (2012) suggests such a customer charge. This can be implemented by charging different customer charges for different groups, dividing residential customers in quartiles of net consumption, as explained in section 4.2.5. When customers add a PV system, they can enter a lower quartile and hence pay a reduced customer charge.

The quartile customer charge system was simulated for the 226 customers in the sample. Using a California residential annual consumption distribution[99], I sorted each customer in one of the four quartile customer charge groups. Without a PV system, 12% were in the lowest quartile of California consumers, 19% were in the second-lowest, 30% were in the third, and 38% in the top quartile of California residential electricity consumers. As increasing PV system sizes were simulated, customers were slowly transitioned into lower quartile groups, until over 95% of customers in the sample belong to the lowest net consumption quartile at a 75% PV-to-load ratio; this progression is seen in Figure 56.

[99] From Reiss and White (2005). The lowest quartile of consumers in CA consume less than 4450 kWh/year, the second quartile consume 4450-6580 kWh/year, the third quartile consume 6580-9700 kWh/year, and the highest quartile consume over 9700 kWh/year.

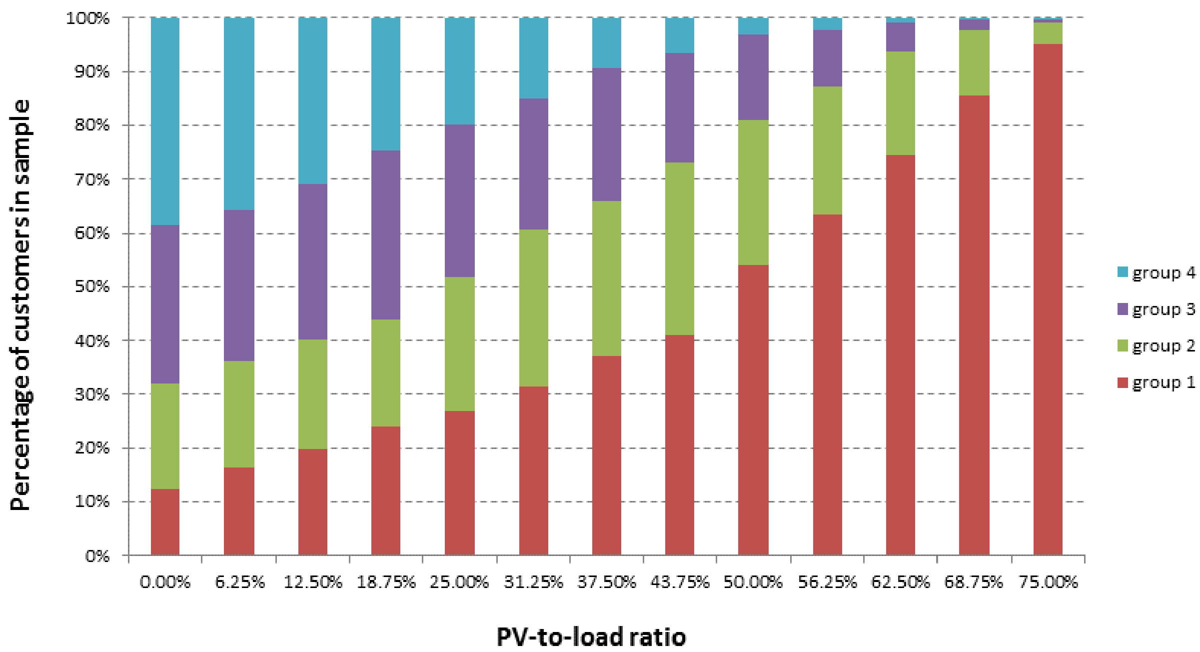

Figure 56: Impact of increasing PV-to-load ratio on customer charge group distribution.

Switching from group 4 to group 1 has major implications on the value of bill savings. A California customer on a two-part flat tariff would increase their value of bill savings by over $1,000/year.[100] Going from group 3 to group 1 and from group 2 to group 1 would increase a customer's bill savings by over $700/year and $350/year, respectively. A customer who starts out in the lowest group would not have any additional bill savings as their customer charge would remain the same.

[100] The customer charge is calculated to be $708/year if fixed for all customers, $354/year for customers in the lowest quartile of electricity consumers, $708/year for customers in the second lowest, $1063/year for customers in the third, and $1417/year for the largest consumer quartile.

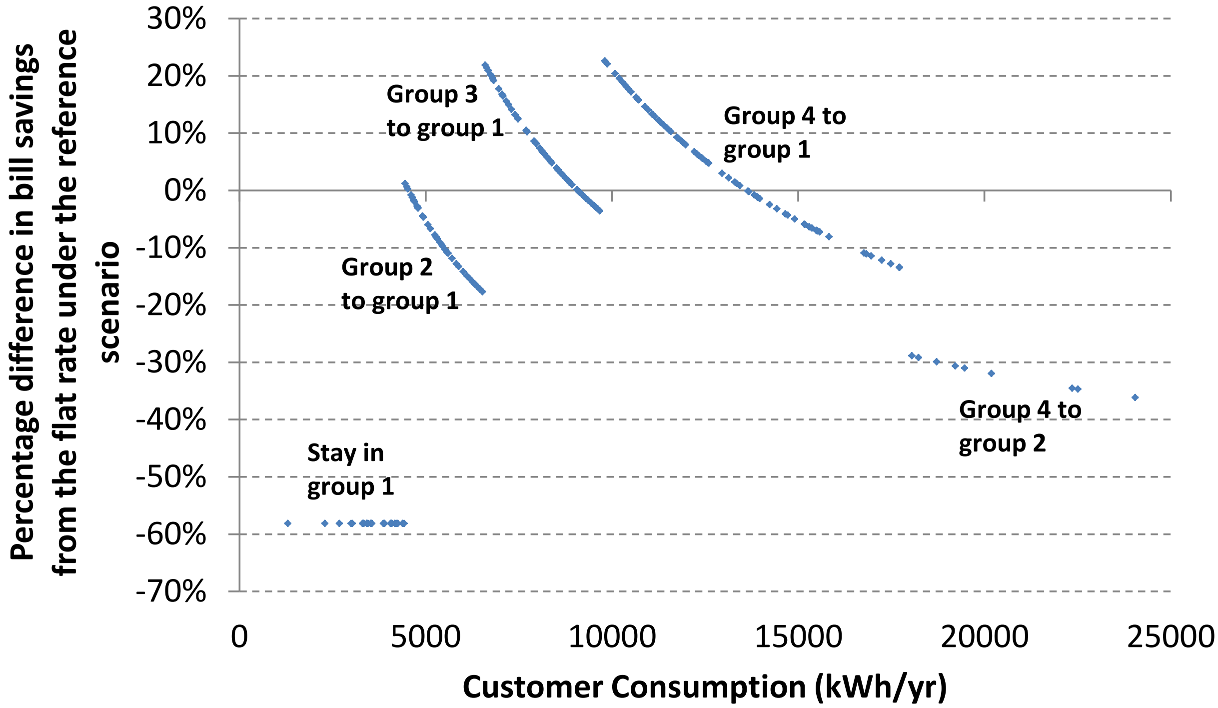

Figure 57. Bill savings for the reference scenario assuming a two-part HOOP rate, relative to the flat rate with the reference scenario assuming volumetric rates. Assuming a 75% PV-to-load ratio.

If we combine bill savings from switching of groups to the bill savings from the variable portion of the bills, and compare this to the flat rate with net metering, we see than smaller consumers with PV systems are least well off compared to larger consumers with PV systems. This is due to the fact that they are already on the lowest customer charge group, and receive no additional savings from adding PV. Figure 57 shows the bill savings from PV for customers with the flat HOOP rate and a 75% PV-to-load ratio, assuming net metering and under the reference scenario, relative to the flat rate assuming volumetric rates, as a function of annual customer consumption. The smallest consumption customers in the sample do not receive any value from the customer charge, since they start on the lowest customer charge and remain on it. They only receive value from the variable portion of the rate, which is equal to the bill savings under the non-HOOP rate (see first point of the right panel in Figure 54); these customers receive 58% less bill savings per kWh than customers with the flat volumetric rate. With a 75% PV-to-load ratio, customers who start in group 2 (with higher annual consumptions) end up in group 1. This leads to an increase in value of bill savings relative to the customers who start in group 1 (a 16% decrease to a 1% increase compared to the bill savings per kWh with a flat volumetric rate). The range and steep negative slope observed within this group is explained by the fixed savings that these customers receive for moving from group 2 to group 1; hence the smallest consumers within the group receive the largest value *per kWh generated*. The largest customers who start in group 2 receive the lowest bill savings per kWh of all those who start in group 2. Next, customers who start in group 3 and end up in group 1 after installing PV receive an even higher bill savings, particularly those customers with the lowest consumption within that group (ranging from a 3% decrease to a 22% increase in bill savings per kWh compared to customers with a flat volumetric rate). Customers who start in group 4 receive about the same bill savings per kWh as those who start in group 3.[101] As consumption within the consumers starting in group 4 increases, so does PV generation at a fixed 75% PV-to-load ratio, and hence the bill savings per kWh decreases (the total range for this group is a 13% decrease to a 23% increase in bill savings per kWh of PV generated relative to a flat volumetric rate). The highest consumers do not fall into group 1 after adding PV with a 75% PV-to-load ratio, but into group 2, and hence their bill savings per kWh decreases to 29%-36% lower than the flat rate with the volumetric charge.

4.4.3 Increasing block pricing

Some utilities, including California IOUs, offer IBP or tiered flat rates. With tiering, volumetric charges increase with each subsequent usage tier, and utilities typically have 2-5 tiers. The original rationale for tiered rates was to encourage lower total electricity consumption and to provide a baseline level of electricity at a low price (for the lower income customers). Tiering, however, does not take the timing of consumption into account and there is no clear theoretical method for designing tiered rates. Hence the central analysis does not include tiering. I did however design a tiered rate for the flat rate in the reference scenario to analyze the impacts of tiering on the value of bill savings.[102] See section 4.2.5.3 for the tiered rate design methodology used in this analysis. The tiered rates for the reference scenario are shown below in Table 23.

Table 23: Tiered flat rate for reference scenario ($/kWh)

	Tier 1	Tier 2	Tier 3
$\boldsymbol{R_{total}}$	0.120	0.180	0.360

I computed utility bills for the customer sample using this rate option with and without PV for three PV system sizes (25%, 50%, and 75% PV-to-load ratio) in order to calculate the value of bill savings for each customer. Similar to the results in Chapter 2, customers with the highest consumption levels who faced high marginal costs in the third tier had the highest level of bill savings from PV (a 102% increase over the non-tiered flat rate), and those with the lowest consumption levels had the lowest bill savings from PV (about 33% lower than the non-tiered flat rate), as can be seen in Figure 58.

The value of bill savings from PV decreases with increasing PV-to-load ratios, particularly for customers in the upper tiers. As PV generation increases, net consumption enters the lower tiers, and hence the marginal value of PV generation is at a lower-tiered rate. This results in lower average customer value from PV generation.

[101] The lowest consumers that start in group 4 receive the same bill savings, approximately, than the lowest consumers that start in group 3. This is due to the quartile distribution – the customer charge increases roughly by the same percentage as the consumption (i.e. the bill savings from the customer charge increases by 50% from group 3 to group 4 and the consumption level increases by 47% from 6580 kWh to 9700 kWh).
[102] This analysis uses the reference scenario for 2030 to design the tiered flat rate. For a more detailed analysis of the impact of actual tiered rates available in CA (as of 2009) on the value of bill savings from PV, see Darghouth et al., 2011.

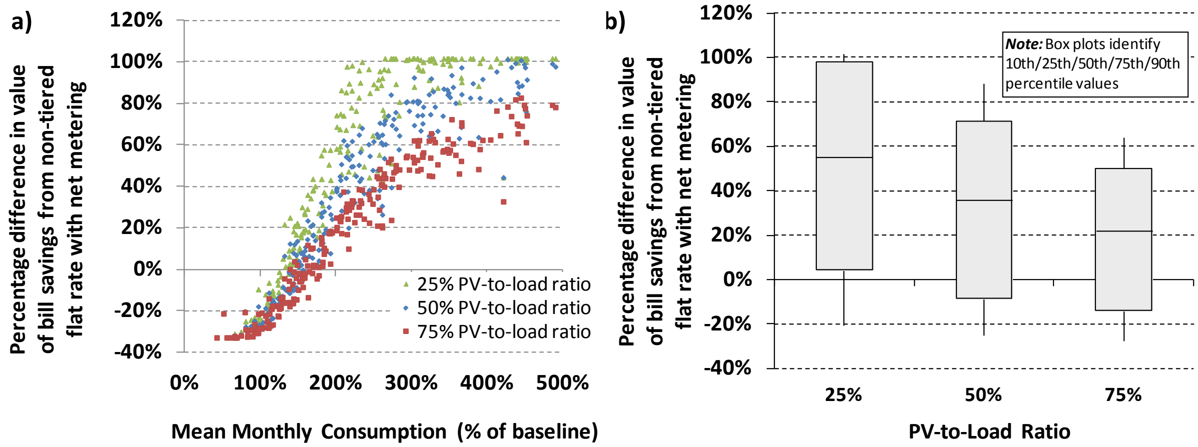

Figure 58: a) Value of bill savings for PV customers under the tiered flat rate as a function of customer gross electricity consumption, for three levels of PV-to-load ratios under the reference scenario. b) Box-and-whiskers plot showing distribution in value of bill savings for PV customers under the tiered flat rate for three levels of PV-to-load ratio. All values are in percentage difference from the non-tiered flat rate with net metering from the reference scenario (hence the more positive the value on the y-axis, the higher the value of bill savings).

These results are dependent on the assumptions used in the design of the tiered rate. The steeper the increasing block prices, the higher the differences between the lowest and highest tiers and the non-tiered flat rate. However, these results indicate that the variation of impact of a tiered rate on value of bill savings from PV can be greater than the variation associated with other rate options and compensation mechanisms, depending on the design of the price tiers.

4.5 Conclusions

Given the prevalence of net metering for U.S. residential PV system owners, retail electricity rates are a central component of the customer-economics of PV. Even if net metering does not remain the primary compensation mechanism for PV customers, any approach allowing customers to displace some of their consumption with PV generation would effectively compensate a portion of PV generation at the retail rate (i.e., by treating it as a decrease in net customer load). Retail rates, in turn, may evolve over time in response to changing electricity market conditions, with a corresponding impact on the value of bill savings from customer-sited PV. Using California-based assumptions, I seek to examine both the sensitivity of the value of bill savings from residential PV to changes in electricity market conditions and the dependence of those sensitivities on prevailing residential rate designs and PV compensation mechanisms. In general, the ranges in the value of bill savings imply significant long-term uncertainty in the economic value for PV system owners.

One central issue addressed in this chapter is the effect of greater aggregate solar penetration on the value of bill savings from behind-the-meter PV, leading to a number of key, inter-related findings. In general, higher solar penetration levels significantly reduce the value of bill savings for customer-sited PV under time-varying retail rate structures, but the erosion in bill savings can be dampened by several factors. In Mills and Wiser (2012), the wholesale economic value of solar electricity was found to decline significantly with increased grid penetration of solar. This occurs because significant solar generation during the afternoon shifts the time of peak "net" load (system load minus PV generation) into the evening hours, causing the temporal profile of hourly wholesale electricity prices to become uncorrelated or negatively correlated with PV output. If all electricity generated by a customer-sited PV system were compensated at the wholesale price (e.g.., without possibility of displacing load), the effects on the value of bill savings from customer-sited PV would be similar to those in Mills and Wiser (2012): a significant drop in value as solar penetration on the grid increases, as found with the side analysis of the two-part tariff with RTP (in section 4.4.2). However, when PV generation from behind-the-meter PV is compensated at the retail rate (i.e. for all other than the two-part tariff with RTP, as implemented in the side analysis), the drop in bill savings is diminished by the averaging of prices under flat rates and TOU rates. In addition, to the extent that the cost of renewables is greater than conventional generation, higher renewables penetration will tend to increase average retail rates, thereby increasing the value of bill savings from behind-the-meter PV.[103] Regardless, with time varying rates or hourly netting or both, there still is a substantial decline in the value of bill savings for residential PV as overall solar penetration increases. For solar deployment to continue to grow under these circumstances will require continued cost reductions or alternate subsidizations of solar support or both.

The results show that, contrary to conventional wisdom, even in summer-peaking electricity systems, net-metered PV does not always benefit from time-varying retail rates, such as TOU or RTP, which provide more efficient price signals to customers than flat rates. Under the reference case scenario and other scenarios with low solar penetration, the value of bill savings from net-metered PV is, as one would typically assume, greater under time-varying rates than under the flat rate, due to the positive correlation between PV output and high wholesale electricity market prices in the California market. These results hold even in the side analyses which consider recovering capacity costs as volumetric charges and two-part tariffs. Under high solar penetration scenarios, however, wholesale market prices tend to be relatively low during periods when PV generation occurs, for the reasons described above, reducing the value of bill savings for customer-sited PV on time-varying rates. As a result, with high solar penetration levels on the grid, the value of bill savings from net-metered PV may be greater under flat rates than under time-varying rates. Within the 15% solar penetration scenario in the central analysis, for example, the median value of bill savings for net-metered PV under a flat rate is 18% greater than under TOU, and is 37% greater than under RTP. As solar penetration levels on the grid increase, policymakers may therefore need to balance competing goals of, on the one hand, encouraging efficient retail rate designs and, on the other hand, supporting deployment of customer-site PV, especially if net-metering continues to be the primary PV compensation mechanism. Even at relatively low solar penetration levels, TOU and RTP rates may not necessarily result in increased bill savings for behind-the-meter PV. In electricity systems with peak loads in winter months during evening hours, for example, one would anticipate that TOU and RTP rates would lead to a decline in the value of bill savings relative to the flat rate even in low solar penetration scenarios (though this has not been explicitly modeled in this analysis).

[103] This is the case so long as these costs are recovered through volumetric charges in the retail rate, which is the case for all rates considered in this analysis, except for the two-part tariff with real-time pricing.

Consistent with the findings in chapter 2, the present study also demonstrates that net metering clearly and significantly enhances the value of bill savings for behind-the-meter PV, relative to hourly netting arrangements where customers receive the hourly wholesale price for PV electricity generated in excess of consumption within each hour. Across the set of scenarios and rate options examined within the central analysis, the median bill savings is 23%-47% lower under hourly netting than under net metering at a 75% PV-to-load ratio. The most acute erosion of bill savings with hourly netting occurs under scenarios with high solar penetration, as a result of the reduced wholesale electricity prices during periods when behind-the-meter PV is exported to the grid. These results suggest that net metering may become an even more valuable (but more costly) policy for behind-the-meter PV as solar penetration levels increase.

The bill savings under the hourly netting mechanism modeled within the analysis are lower than under net metering in our central analysis, because hourly net excess generation is assumed to be compensated at wholesale electricity prices, which on average are lower than retail rates. Were a higher price paid for net excess generation—e.g., to provide compensation for other benefits provided by PV beyond avoided wholesale electricity market purchases—then the erosion in bill savings would be reduced. Should pressure mount to replace or revise net metering, it will therefore become increasingly important to develop methods for valuing the diversity of costs and benefits from behind-the-meter PV that can be used to inform the design of alternative compensation mechanisms for behind-the-meter PV.

At high solar penetration levels, grid-level storage, customer demand response, and CSP with thermal storage may be deployed in greater quantities in order to ease integration challenges. These resources dampen wholesale electricity price volatility and, at high solar penetration levels, increase average prices during periods when PV is generating. As a result, greater deployment of these resources generally reduces the erosion in bill savings that otherwise occurs at high solar penetration levels for behind-the-meter PV with time-varying retail rates. For example, when higher levels of demand response are added to the standard 33% RE scenario modeled in this study, the median value of bill savings increases by 3% for net-metered PV on TOU and by 10% for net-metered PV on RTP. These kinds of strategies are aimed principally at easing the integration of large amounts of variable generation, and any impact on the value of bill savings for individual behind-the-meter PV systems is incidental. There are, however, potential techniques that could be employed for the explicit purpose of maximizing the value of bill savings from behind-the-meter PV. Such strategies, which have not been explored in this chapter but could be the subject of future research, include customer-sited storage and/or advanced load control technologies deployed in conjunction with behind-the-meter PV. Behind-the-meter storage and customer load control could both be used to maximize PV exports to the grid during periods of high retail rates (under net metering) or if compensation were provided through some kind hourly netting mechanism, to minimize hourly excess electricity generation. The deployment of such strategies may become even more important in the face of increasing solar penetration levels and/or challenges to existing net metering policies, in order to stem any erosion in the value of bill savings from behind-the-meter PV.

This study also examined the sensitivity of the bill savings from behind-the-meter PV under a variety of other scenarios, including those with increased wind penetrations, a $50/ton carbon price, and changes in the price of natural gas. In general, these scenarios lead to relatively uniform increases or decreases in wholesale electricity prices across all hours and therefore relatively uniform changes to retail rates. Thus, while the bill savings from behind-the-meter PV is impacted (in some cases, substantially so) under these scenarios, the magnitude of the impact is largely independent of the design of the retail rate (flat, TOU, or RTP). For example, under the $50/ton carbon price scenario, the median value of bill savings is 9%-21% higher than under the reference case, assuming net metering, a 75% PV-to-load ratio, and depending on the rate design (a relatively tight range compared to the high solar penetration scenario, where the effect on the median value of bill savings ranged from an 8% increase to a 21% decrease under net metering, depending on the rate design).

In addition to the central analyses, I also considered three side analyses with a different wholesale market design or retail rate structure: (a) retail rates based on a wholesale market design with a price cap and recovering capacity costs through a time-invariant volumetric charge; (b) rates with a two-part tariff, recovering fixed charges through a fixed customer charge; and, (c) a flat rate with increasing-block pricing (IBP). These are either currently implemented or have been considered by US utilities or public utility commissions as alternatives to existing rates.

The wholesale market modeled in the central analysis in this study is an energy-only market where generators recover some portion of their fixed costs during hours in which scarcity pricing pushes wholesale electricity prices higher than marginal costs. In the side analysis, I also considered an alternative market design that many organized wholesale electricity markets in the United States currently adopt, consisting of an energy market with price caps and a parallel capacity market that serves to ensure resource adequacy. Under this kind of market design, wholesale electricity prices are less volatile than under an energy-only market design; however, the capacity payments create an additional cost that must be recovered through retail rates. In the side analysis, I chose to recover these via a flat volumetric adder for retail residential customers, as is the case in most U.S. utilities today. The differences with the energy-only market can affect retail rates and the value of bill savings for behind-the-meter PV in several important ways. Though there is no change in the value of bill savings under flat retail rates, time-varying rates are affected with a reduction in prices during periods or hours when the wholesale price cap is reached and an increase in prices during all other periods or hours, due to the additional capacity volumetric adder[104]. This results in only a small increase in the value of bill savings for customers with the time-varying rates and net metering under the reference scenario, since PV generates in hours with scarcity prices that would be reduced due to the price cap (TOU and RTP with net metering lead to savings that are only 2% and 5% higher than the flat rate with net metering, respectively). Conversely, in electricity market scenarios with higher PV penetrations, the value of bill savings increase, as the price spikes in these scenarios do not occur when PV generates and thus the reduction in energy costs during those hours does not affect PV compensation, while the additional volumetric charge to recover capacity market costs leads to an increase in retail rates during hours when PV generation occurs (TOU and RTP with net metering lead to savings that are 7% and 18% higher than with the energy-only market, respectively). In short, under an electricity market design featuring an energy market with price

[104] If the TOU and RTP rates are less 'peaky', as a result of policy decisions on how to recover capacity costs through rates for example, then bill savings from PV will be less impacted by PV output correlation with periods of scarcity. This is particularly important for wholesale market scenarios with low PV penetrations, as there is a higher level of correlation between PV generation and periods of scarcity than for higher PV penetration scenarios.

caps and a parallel capacity market, the erosion in the value of bill savings relative to the flat rate that occurs at high solar penetration levels under TOU and RTP rates are reduced.

The central analysis primarily considered three potential residential retail rate structures (a flat rate, a TOU rate, and an RTP rate), and in all cases fixed costs are recovered through volumetric charges. In some jurisdictions, however, consideration is being given to relying more heavily on customer charges for fixed-cost recovery. Hence, in one of the three side analysis I considered, as a lower bound to value from PV, a case where *all* fixed costs are recovered through a fixed customer charge rather than through a volumetric adder (see section 4.2.5.1 for more details on the rate). The most salient result is the substantial decline, over 50% using the assumptions in this analysis, in the value of bill savings for the flat and TOU rates with net metering, relative to that of the full volumetric rate. The policy implications are also significant; depending on how the rate is designed, moving away from volumetric-only rates to two-part tariffs could have significant implications on the behind-the-meter PV market. To retain demand for PV at a similar level, such a reduction in value from bill savings would have to be countered by a feed-in tariff, an upfront subsidy, or another compensation mechanism to increase the PV system value to the customer.

Using the specified assumptions in the side analysis, I found that the flat and TOU rates are 30-50% worst off than similar rates with volumetric only charges, depending on the compensation mechanism. At low PV grid penetrations, the rates which lead to highest value of bill savings from PV are the time-varying rates, as exemplified in the results with the reference scenario (the TOU and RTP rate lead to savings 30% and 28% higher than the flat rate). As with the volumetric-only rates, the portion of the rates derived from wholesale energy purchases is higher during times of PV generation, and hence PV generation benefits from higher than average rates. With high PV penetrations, the peak prices shift to later in the day when PV stops generating. Hence prices during time when PV generates are low, leading to lower value of bill savings from PV, as seen in the results with the renewable mix scenario (the TOU and RTP rates lead to savings 24% and 31% lower than the flat rate, respectively). Without the volumetric adder, the differences between the two-part tariff time-varying rates and the average wholesale prices are smaller, and hence, for time-varying rates, the impact of moving away from net metering to hourly netting is less significant than with volumetric-only rates.

The severe erosion in bill savings associated with moving towards such a two-part tariff rate structure from a completely volumetric rate would be unsatisfactory for behind-the-meter PV customers and other stakeholders, particularly those who invested prior to the introduction of the two-part tariffs on the expectation that rates would remain entirely volumetric charges. Hence, an intermediate arrangement may be found, such as a two-part tariff where a portion of the customer charge can be offset by PV. In this side analysis, I implemented a two-part tariff rate from Friedman (2012), which suggested a customer charge that varies with historical annual consumption, net of PV generation. I split the customer sample into four groups, corresponding to the four California consumption quartiles. Allowing a customer to enter a lower consumption quartile group with PV generation enables a customer to increase their bill savings from PV by paying a lower customer charge. With a 75% PV-to-load ratio, even large customers fall into the lowest quartile of consumption. In our sample, less than 5% of the customers did not move to the lowest quartile. Using the methods specified in section 4.2.5.2, moving from the largest quartile group to the smallest leads to a reduction in bills, and an increase in effective bill savings from

PV of over $1060/year. Hence this type of rate could be seen as a step in the direction of two-part tariffs with fixed customer charges, without overly impacting the value of bill savings from PV. In fact, this system also maintains some of the incentive structures of IBP, since only the larger customers are able to move down into lower consumption quartiles, and hence can save in their bills more than a smaller customer who is already in the lowest consumption quartile. Moving from an IBP, volumetric-only rate to a rate with a variable customer charge may be a good transition towards fixed customer charges.

Although increasing-block pricing (IBP) was not among the rate structures included within the principal scenario analyses of this study, the side analysis examining the bill savings from PV with IBP under the reference case scenario highlights the significance of this rate structure for the customer economics of behind-the-meter PV. In particular, the variations in the value of bill savings across customers when PV is net-metered with an IBP rate are even more significant than the variations associated with other rate options, compensation mechanisms, and electricity market scenarios. Under IBP, the value of the bill savings is highly dependent on the customer's monthly usage, such that customers with high levels of usage receive a relatively a high value of bill savings from PV (and the converse for customers with low consumption levels), with the magnitude of this variability depending on the steepness of the usage tiers. For example, using the rate-design parameters specified in this chapter for a flat rate with IBP (which are based roughly on current IBP residential rates in California), customers in the lowest consumption tiers receive a value of bill savings from PV that is 33% lower than for customers on the non-tiered flat rate with net metering. Customers in the highest tier receive a value of bill savings from PV that is up to 102% higher than the non-tiered flat rate, depending on their PV system size (generally for IBP rates, the lower the PV system size, the greater the average value of bill savings from PV). This suggests that the introduction of IBP rates, and/or revisions to existing IBP rates, may have an even greater impact on the value of bill savings from behind-the-meter PV than the other uncertainties explored within this chapter.

The foregoing conclusions must be understood within the context of the specific assumptions and limitations of this study. The following paragraphs identify the key assumptions and limitations and discuss their implications for the results and conclusions of this analysis.

- **Assumptions Specific to California's Electricity Market.** The analysis in this chapter relies on a variety of assumptions that are based loosely on California's electricity market, and the results of the analysis could differ if assumptions characteristic of other regions were used instead. Three California-specific aspects of the assumptions are particularly worth noting. (a) *Fixed Cost Levels*. The retail rates developed under each scenario were constructed to recover fixed costs through a flat volumetric adder, and in California, fixed costs associated with T&D and other miscellaneous costs are relatively high. Lower fixed costs, would impact the results of the central analysis in several ways. First, it would reduce the difference between the value of bill savings on net metering and hourly netting, as that difference partially derives from the fact that, under hourly netting, the price paid for net excess generation excludes the volumetric adder (for all but the two part tariff). Second, it would cause the value of bill savings on time-varying rates to become more sensitive to changes in the wholesale electricity prices (in terms of the percentage change in the value of bill savings between scenarios). This latter effect occurs because the flat volumetric adder remains relatively stable across scenarios, and therefore dampens any percentage change in the value of bill savings associated with changes to wholesale electricity prices. When the fixed costs cannot be displaced, as is the case for the side analysis of the two-part tariff, lower T&D costs would not impact the value of bill savings. (b) *Summer Afternoon-Peaking Load Profile*. Although afternoon-peaking load profiles are common for areas with high afternoon temperatures in the summer season, some regions have a winter evening-peaking load, due to the reliance on electric space heaters, for example. In these cases, the value of bill savings from PV in the reference case will generally be lower when compensated under time-varying rates, as PV would not generate at times when wholesale market prices are highest. Hence, the *decrease* in value of bill savings that occurs under high solar penetration scenarios would be less severe. (c) *Generation Mix*. Many states have a different generation mix than California (for example, some regions may have a greater proportion of existing coal generation). Depending on the interactions between PV penetration and the marginal cost of generation when PV generates, this has implications for the wholesale electricity price profiles, which, in turn, influence retail rates and value of bill savings from PV, depending on the particulars of the generation mix.

- **Focus on Residential Customers.** Although some aspects of the findings may be generalized to non-residential customers, two particular factors limit any broader applicability. First, commercial load profiles tend to peak earlier in the day than residential profiles, and are better correlated with PV generation. As a result, under hourly netting, commercial customers would likely see fewer hours with PV generation in excess of load, and thus a smaller erosion of bill savings relative to net metering. Second, retail rates for commercial customers often include a demand charge (e.g., based on the customer's monthly peak load). Behind-the-meter PV may reduce demand charges, but the magnitude of the demand charge savings is highly sensitive to the customer's load shape, the PV system size relative to the customer's load, and the design specifications of the demand charge itself (Wiser et al., 2007). How various electricity market scenarios would impact a demand charge would depend on the design of the demand charge (for example, whether it is an annual or time-of-day demand charge).

- **Limited Set of Wholesale Market Scenarios and Assumptions.** In the interest of maintaining a tractable set of comparisons, the analysis included a limited number of wholesale market scenarios. In addition, each of the scenarios required certain assumptions – for example, within the high and low natural gas price scenarios, specific assumptions about the trajectory of natural gas prices. The purpose of my work was not to develop projections or to assess the full breadth of possible future trajectories, but to examine the *sensitivity* of the bill savings from residential PV to underlying changes in key electricity market conditions – for example, by showing that under the particular electricity market and set of rate designs simulated, a 25% increase in the price of natural gas increases the value of savings from PV by only a few percent. That being said, further analyses may be warranted to examine additional wholesale market uncertainties or variants on the set of scenarios included within this study.

- **Focus on Hourly Netting as the Alternative to Net Metering.** This study considers one hypothetical alternative to net metering: hourly netting, whereby customers can offset the entirety of their load in any hour, but any excess hourly PV generation is assumed to be compensated at the prevailing hourly wholesale electricity market price. This approach treats behind-the-meter PV similar to energy efficiency, to the extent that the PV generation simply reduces consumption, but PV production that is exported to the grid is compensated in the same way as conventional generators selling into the wholesale market. Any number of other alternative compensation schemes to net metering may exist, however, including other variants of hourly netting (e.g., where the netting is done on a sub-hourly basis or where the price paid for net excess generation is not the hourly wholesale electricity market price). One particular alternative to net metering not considered in this study is a feed-in tariff (FIT), whereby 100% of all PV generation is compensated at some fixed price or schedule of prices over a predetermined period of time. The compensation provided under a FIT could be higher or lower than the value of bill savings received under net metering or hourly netting, depending on the administratively determined feed-in tariff price. Given that a FIT price is fixed, however, the compensation is insensitive to changes in electricity market conditions. One variant on a FIT is a "value of solar rate," such as that recently developed by Austin Energy, whereby PV generation is compensated at a price that is recalculated annually to reflect the value of solar generation to the utility (Rábago et al., 2012). Such a rate would be affected by changes to electricity market conditions, though the degree of sensitivity relative to net metering would depend on the particular details of the value of solar rate.

Despite these limitations, this chapter's most basic finding is broadly applicable: future electricity market scenarios, retail rate structures, and the availability of net metering interact to place substantial uncertainty on the future value of bill savings from residential PV. In addition, this chapter's methodological framework can be applied to a variety of electricity market designs, retail rate structures, and PV compensation mechanisms that were not explicitly addressed here to better understand how a particular scenario may impact retail electricity rates and the value of bill savings from behind-the-meter PV. Bearing in mind some of the caveats addressed above, the higher-level trends may be applicable to a broad array of conditions when evaluating the longer term outlook for retail rates and the customer economics of behind-the-meter solar.

Chapter 5 CONCLUSIONS

Renewables have the potential to greatly reduce GHG emissions in the electricity sector, but have thus far needed incentives to grow their market size. This dissertation builds on the emerging literature on net metering and compensation mechanisms for solar, with a focus on residential, behind-the-meter PV. The second chapter of the dissertation explores how differences in rate structures affect the value of the bill savings provided through net metering, using California as a case study. Net metering, in combination with other policy support mechanisms, has been instrumental in stimulating the market for distributed PV in California and elsewhere in the U.S. One inherent feature of net metering is that the bill savings are dependent on the underlying retail rate structure. Understanding the manner and degree to which retail rate design affects the economics of net metered PV, and the relative value of net metering compared to other potential compensation mechanisms, is therefore critical for policymakers and utilities seeking to support the deployment of distributed PV.

The analysis is based on the specific retail rates and net metering rules offered by PG&E and SCE, California's two largest utilities, including the flat rate and more efficient time-of-use rates, and on a sample of residential customers in the two utilities' service territories. In addition, I explore the potential impact on bill savings of replacing net metering and moving towards an avoided-cost compensation, to understand how large the "subsidy" associated with net metering is to PV owners, using three potential alternative compensation mechanisms all based on the same avoided-cost valuation. The analysis yields the following key findings regarding the impact of retail rate design on the economics of net metered PV:

- Inclining block rates, such as those offered by PG&E and SCE, provide differentially greater support for PV adoption among high usage customers. In the case of PG&E and SCE, this dynamic is particularly pronounced, given the utilities' particularly steep usage tiers.
- The relative attractiveness of time-of-use (TOU) pricing for customers with net metered-PV is mixed and depends highly on what alternative rate structures are available, the characteristics of the customer load profile, and the size of the PV system relative to the customer's load. With respect to the latter, our analysis shows that, if the PV system is sized to meet only a small fraction of the customer's load, TOU rates may yield lower bill savings than a non-time-differentiated rate, due to the TOU's fixed daily charge which is large enough to offset the cost advantage that the TOU rate would otherwise provide.

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

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

The analysis in the second chapter focuses on current rates and hence does not take into consideration potential changes to wholesale market conditions or retail electricity rate structures. Such changes would impact retail rates and hence bill savings from PV, under net metering or any compensation mechanism that would compensate any part of PV generation at time-varying retail rates or wholesale prices. The third chapter shows that changes in wholesale market conditions, such as increased PV penetrations, can impact wholesale prices. This chapter uses the merit-order effect framework to quantify short-term price effects of PV generation, and provides motivation for using a more sophisticated model, which incorporates changes in the generation mix as well as operational constraints, in the following chapter.

By adding zero-marginal cost PV generation to the wholesale market, more expensive generators are displaced and hence the market-clearing wholesale market price is reduced. This analysis uses generation and load bids into the CAISO pool to reconstruct supply and demand curves. I simulate various levels of PV generation, which shifts the supply curves outwards each hour PV generates, and estimate the reduction in value of PV generation relative to today's level of PV penetration. I find that the wholesale value of PV erodes significantly, and the erosion accelerates at PV penetration levels over 7%. The reduction in value of PV in the wholesale market, relative to today's PV generation levels, reaches about 50% at a 10% PV penetration level. However, I discuss a number of limitations to this method in the chapter conclusions, most significantly that the bidding behavior and generation mix is static with increasing PV penetration. Adding PV generation to the generation mix would result in a change in the conventional generation mix, in order to accommodate the variable generation source. In addition, PV generation can ramp up and down very quickly, and hence conventional generation operational constraints become particularly important to take into account. The limitations of the basic merit-order effect method to quantify price impacts of PV generation point towards the need for a model that can take into account both changes in the conventional generation mix and its operational constraints. In the following chapter, I use an hourly economic dispatch and investment model, developed by Mills and Wiser (2012), to simulate wholesale price impacts from a number of changes in wholesale market conditions.

Though a number of authors have focused on the wholesale price effects of changing wholesale market conditions, the fourth chapter of the dissertation is the first known effort to link changes in wholesale market conditions to retail prices and implications for PV. Most generally, it finds that there is uncertainty in future bill savings from behind-the-meter, residential PV, as these are greatly dependent on wholesale market conditions, retail rate structures, and availability of net metering.

More specifically, one of the chapter's main findings is the effect of increased PV penetration on bill savings from behind-the-meter PV. For electricity market scenarios without an increase in solar penetration beyond the reference case level, TOU rates provide the greatest bill savings value among the three rate options considered, followed by RTP. In these low-solar-penetration scenarios, TOU and RTP yield a higher value of bill savings than the flat rate because wholesale electricity prices are generally higher than average during times that PV generates electricity (i.e., PV output is positively correlated to summer peak load), and PV generation therefore benefits from time-differentiated compensation. The modeled TOU rate, calculated using a clustering algorithm to identify TOU periods, results in higher bill savings than the RTP rate because PV customers benefit from the averaging of hourly wholesale electricity prices over the peak TOU period, thereby increasing the average effective compensation rate of PV generation compared with RTP.

In stark contrast, for all scenarios with high solar penetration, the flat rate provides the greatest bill savings, followed by the TOU rate, followed by RTP. In these higher-solar-penetration scenarios (with greater than 10% of total electricity generation from PV), hourly wholesale electricity prices are generally lower than average when PV generates electricity because significant solar generation during the afternoon shifts the time of peak "net" load (system load minus PV generation) into the evening hours, also shifting the temporal profile of hourly wholesale electricity prices to be negatively correlated with PV output. As a result, the TOU and RTP rates, which are time varying and directly related to wholesale prices, provide lower value of bill savings from PV than does the flat rate, respectively. Given this and the previous finding, whether flat, TOU, or RTP rates provide the most benefit to residential PV customers depends critically on the level of solar generation within the regional electricity grid.

High PV penetration levels reduce the value of bill savings under most combinations of rate options and compensation mechanisms evaluated in this report other than the flat rate with net metering. Sizable declines in bill savings can occur even at relatively low PV penetration levels, although the degree of decline depends on the retail rate structure and compensation mechanism. Specifically, in this scoping analysis, for TOU rates, the value of bill savings declines particularly steeply at PV penetrations of just 2.5%-7.5% (and then declines more slowly at higher PV penetration levels), whereas for RTP and for flat rates with hourly netting, the value of bill savings declines more linearly with grid PV penetration levels.

At high renewables penetration, the bill savings from PV increase with greater deployment of grid storage, demand response, or CSP with storage. Other analyses have highlighted the potential value of storage and demand response as a way to integrate large amounts of renewables into the grid, and our results show that storage and demand response also enhance the bill savings from behind-the-meter PV. These strategies shift prices such that they are higher during times when PV is generating, compared to the price profile in the core 33% renewable energy mix scenario, leading to increased average compensation rates for behind-the-meter PV. The value of bill savings is also higher due to increased retail rates resulting from the additional utility costs of CSP and storage.

Similarly, with time-varying retail rates based on a wholesale price cap and capacity cost volumetric adder (spread equally over all hours), bill savings from PV do not erode as significantly as in the central analysis when moving from the reference scenarios to the 33% renewables scenario, due to a combination of the lower wholesale price volatility (i.e. smaller price spikes) and the capacity cost adder increasing rates over all hours. In the reference scenario with time-varying rates, the total bill savings is similar to the central analyses; even though the wholesale prices are lower than in the central analysis during peak price hours, this is countered by the increase in the volumetric adder. Hence the shift in the price peaks to times in the early evening does not impact bill savings significantly in the 33% renewables scenario.

Moving away from volumetric charge towards a two-part tariff, where T&D costs are recovered through a fixed customer charge, leads to a decrease in bill savings from PV, since PV generation can only displace the volumetric portion of the rate for flat and time-of-use rates. Hence moving towards a two-part tariff would have significant implication for the customer economics of behind the meter PV. Implementing HOOP rates which would allow customers to decrease their customer charge by adding PV would decrease the erosion in bill savings, but only for the higher electricity consumers. Smaller consumers would not be able to lower their customer charge, as their customer charge would already be low. Moving from a volumetric rate with increasing-block pricing to a two-part HOOP rate would maintain some of the incentives for larger customers to install PV, as larger customers have more to gain from PV under this rate structure than the smallest consumers.

In most wholesale market condition and rate option combinations, hourly netting significantly erodes bill savings, relative to net metering. Under hourly netting, PV customers receive the retail rate for PV generation that displaces hourly load but the hourly wholesale price for any electricity generated beyond their electricity consumption within each hour. Over most hours in which hourly excess PV is exported to the grid, wholesale prices are lower than retail rates (whether flat, TOU, or real time pricing), yielding a sizable decrease in the value of bill savings, particularly when hourly exports are a sizeable portion of total PV generation. As a result, the bill savings from PV are 23% to 47% lower with hourly netting than with full net metering, depending on the electricity market scenario and rate option, at a 75% PV-to-load ratio. If the compensation rate for net excess generation exceeded the hourly wholesale electricity price, e.g., if compensation was provided for other benefits provided by PV, such as avoided transmission and distribution costs and losses, then this reduction in value would be lower. One exception to this finding is the flat rate with the two-part tariff under the reference scenario. In this case, the average wholesale price when PV generates is higher than the flat rate, since the flat rate does not include a T&D volumetric adder.

The dissertation uses use data from California throughout its analysis, but most generally, results are applicable to other wholesale market conditions, even if specific numbers are different. At the highest level, I have shown that changing wholesale market conditions, rate structures, and availability of net metering will change customer economics of PV, and this is applicable to most regions, even if numbers are different in some cases. This is the first known analysis linking wholesale and retail market conditions, and provides a framework for understanding how current rate structures can impact bill savings as well as how future wholesale market conditions, rate structures, and PV compensation mechanisms can impact the residential customer economics of behind-the-meter PV.

My findings imply that under certain conditions (e.g. high PV penetrations with time-varying rates, or high customer charges), an explicit support mechanism such as a performance-based incentive will be needed to maintain existing subsidy levels. Depending on how much costs continue to decline, PV systems will need an explicit subsidy in addition to net metering, or an alternative compensation mechanism, in order to maintain net costs for customers and increase the behind-the-meter PV market.

This dissertation also challenges the idea that there is a single PV price level at which residential PV generation will have reached grid parity levels; grid parity may in fact be a moving target. As PV penetration increases, the residential PV price for grid parity decreases as bill savings from PV decreases, under certain wholesale market conditions and rate options. Under other conditions, an increased PV penetration may lead to a higher PV price for grid parity. Hence there is not necessarily a single cost level at which PV becomes grid-parity; the grid parity cost level is very much dependent on the wholesale market conditions. This has policy implications for PV price targets; government programs whose goal it is to reduce the price of PV to grid parity should take into account potential future wholesale market conditions.

Chapter 6 REFERENCES

Alvarado, A., 2012. Levelized Costs of California Central Station Electricity Generation Technologies. Presented at the California Energy Commission. Retail Rate and Cost Issues with Renewable Development Workshop, May 22, 2012.

Barnes, J., Varnando, L., 2010. The Intersection of Net Metering & Retail Choice; An Overview of Policy, Practice, and Issues. Interstate Renewable Energy Council, Latham, NY.

Bonbright, J., 1961. Principles of public utility rates, 2nd ed. Columbia University Press, New York.

Borenstein, S., 2005a. Time-varying retail electricity prices: Theory and practice. Electricity Deregulation: Choices and Challenges.

Borenstein, S., 2005b. The long-run efficiency of real-time electricity pricing. Energy Journal 26, 93–116.

Borenstein, S., 2007. Electricity Rate Structures and the Economics of Solar PV: Could Mandatory Time-of-Use Rates Undermine California's Solar Photovoltaic Subsidies? (Working Paper No. CSEM WP 172). UC Energy Institute, Berkeley, CA.

Borenstein, S., 2008. The Market Value and Cost of Solar Photovoltaic Electricity Production (Working Paper No. CSEM WP 176).

Borenstein, S., 2011. Effective and Equitable Adoption of Opt-In Residential Dynamic Electricity Pricing (No. draft). UC Energy Institute, Berkeley, CA.

Borenstein, S., 2012. The Private and Public Economies of Renewable Electricity Generation. The Journal of Economic Perspectives 26, 67–92.

Braithwait, S., 2010. Behavior Modification. IEEE Power and Energy Magazine 8, 36–45.

Braun, M., Stetz, T., Bründlinger, R., Mayr, C., Ogimoto, K., Hatta, H., Kobayashi, H., Kroposki, B., Mather, B., Coddington, M., Lynn, K., Graditi, G., Woyte, A., MacGill, I., 2012. Is the distribution grid ready to accept large-scale photovoltaic deployment? State of the art, progress, and future prospects. Progress in Photovoltaics: Research and Applications 20, 681–697.

Bright Power, Inc, Energywiz, Inc, The Association of Energy Affordability, 2009. Solar Real-Time Pricing: Is Real-Time Pricing Beneficial to Solar PV in New York City? Prepared for the New York City Economic Development, New York, NY.

Bürer, M.J., Wüstenhagen, R., 2009. Which renewable energy policy is a venture capitalist's best friend? Empirical evidence from a survey of international cleantech investors. Energy Policy 37, 4997–5006.

Butler, L., Neuhoff, K., 2008. Comparison of feed-in tariff, quota and auction mechanisms to support wind power development. Renewable Energy 33, 1854–1867.

Caamaño-Martín, E., Laukamp, H., Jantsch, M., Erge, T., Thornycroft, J., De Moor, H., Cobben, S., Suna, D., Gaiddon, B., 2008. Interaction between photovoltaic distributed generation and electricity networks. Progress in Photovoltaics: Research and Applications 16, 629–643.

CAISO (California Independent System Operator), 2010. CAISO Mapping of Location and Profiles Used in One-minute Analysis. California Independent System Operator, Folsom, CA, USA.

CAISO (California Independent System Operator), 2012. Open Access Same-time Information System (OASIS) [WWW Document]. URL oasis.caiso.com

Cappers, P., Mills, A., Goldman, C.A., WISER, R., Eto, J., 2011. Mass Market Demand Response and Variable Generation Integration Issues: A Scoping Study (Report No. LBNL-5063E). Lawrence Berkeley National Laboratory, Berkeley, CA, USA.

CEC, 2012. Electricity Consumption by Planning Area [WWW Document]. URL http://www.ecdms.energy.ca.gov/elecbyplan.aspx

Charles River Associates, 2005. Impact Evaluation of the California Statewide Pricing Pilot (Final Report). Charles River Associates, Oakland, CA, USA.

Clean Power Research, 2012. SolarAnywhere.

Contreras, J.L., Frantzis, L., Blazewicz, S., Pinault, D., Sawyer, H., 2008. Photovoltaics Value Analysis (Subcontract Report No. NREL/SR-581-42303). National Renewable Energy Laboratory (NREL), Golden, CO.

Cook, C., Cross, J., 1999. A Case Study: The Economic Cost of Net-Metering in Maryland: Who Bears the Economic Burden? (Unpublished). Maryland Energy Administration, Annapolis, MD.

CPUC, 2004. Capacity Markets White Paper (Report No. 202004). Energy Division, California Public Utilities Commission., San Francisco, CA, USA.

CPUC, 2010. CPUC LTPP Technical Attachment Spreadsheet. California Public Utilities Commission, San Francisco, CA, USA.

CPUC (Public Utilities Commission of the State of California), 2009. Energy Division Resolution E-4298.

Darghouth, N., Barbose, G., Wiser, R., 2010. The Impact of Rate Design and Net Metering on the Bill Savings from Distributed PV for Residential Customers in California (LBNL Report No. LBNL-3276E). Lawrence Berkeley National Laboratory, Berkeley, CA.

Darghouth, N.R., Barbose, G., Wiser, R., 2011. The impact of rate design and net metering on the bill savings from distributed PV for residential customers in California. Energy Policy 39, 5243–5253.

Database of State Incentives for Renewable Energy (DSIRE), 2010. Map of Net Metering Policies [WWW Document]. URL http://www.dsireusa.org/documents/summarymaps/Net_Metering_map.ppt

De Jonghe, C., Hobbs, B.F., Belmans, R., 2012. Optimal Generation Mix With Short-Term Demand Response and Wind Penetration. IEEE Transactions on Power Systems 27, 830 –839.

DeBenedictis, A., 2010. Personal Communication. Energy and Environmental Economics.

Denholm, P., Drury, E., Margolis, R., 2009. Solar Deployment System (SolarDS) Model: Documentation and Sample Results (Technical Report No. NREL/TP-6A2-45832). National Renewable Energy Laboratory (NREL), Golden, CO.

Denholm, P., Ela, E., Kirby, B., Milligan, M., 2010. The Role of Energy Storage with Renewable Electricity Generation (Technical Report No. NREL/TP-6A2-47187). National Renewable Energy Laboratory, Golden, CO, USA.

Denholm, P., Margolis, R.M., 2007. Evaluating the limits of solar photovoltaics (PV) in traditional electric power systems. Energy Policy 35, 2852–2861.

Dobrow, S.A., Lingaraj, B.P., 1988. Design of time-of-use rate periods for a utility. Journal of Operations Management 7, 25–43.

DSIRE (Database of State Incentives for Renewable Energy), 2013. Map of Net Metering Policies [WWW Document]. URL http://www.dsireusa.org/documents/summarymaps/Net_Metering_map.ppt

Duke, R., Kammen, D.M., 1999. The Economics of Energy Market Transformation Programs. The Energy Journal 20, 15–64.

Duke, R., Williams, R., Payne, A., 2005. Accelerating residential PV expansion: demand analysis for competitive electricity markets. Energy Policy 33, 1912–1929.

E3, 2009. National Time-Dependent Valuation, Methodology Summary (A collaboration with the New Buildings Institute, the COMNET framework, the US DOE and US EPA). Energy and Environmental Economics (E3), San Francisco, CA, USA.

E3, 2010a. Net Energy Metering Cost Effectiveness Evaluation (Prepared for the California Public Utilities Commission). Energy and Environmental Economics (E3), San Francisco, CA.

E3, 2010b. Long Term Procurement Plan; Solar Pricing Pro Forma (Prepared for the California Public Utilities Commission's regulatory proceedings). Energy and Environmental Economics (E3), San Francisco, CA, USA.

E3, 2010c. Greenhouse Gas Modeling of California's Electricity Sector to 2020: Updated Results of the GHG Calculator. Version 3b update (Prepared for the California Energy Commission). Energy and Environmental Economics, San Francisco, CA, USA.

EIA (US Energy Information Administration), 2013. Electric Power Monthly with data for January 2013. Table 5.6.A. U.S. Energy Information Administration, Washington, DC, USA.

Faiers, A., Neame, C., 2006. Consumer attitudes towards domestic solar power systems. Energy Policy 34, 1797–1806.

Faruqui, A., Hledik, R., Tsoukalis, J., 2009. The Power of Dynamic Pricing. The Electricity Journal 22, 42–56.

Faruqui, A., Sergici, S., 2010. Household response to dynamic pricing of electricity: a survey of 15 experiments. Journal of Regulatory Economics 38, 193–225.

Federal Electricity Regulatory Commission (FERC), 2011. 2011 Assessment of Demand Response & Advanced Metering: Staff Report. Federal Energy Regulatory Commission, Washington, DC, USA.

Feldstein, M.S., 1972. Equity and Efficiency in Public Sector Pricing: The Optimal Two-Part Tariff. The Quarterly Journal of Economics 86, 176–187.

Finon, D., Perez, Y., 2007. The social efficiency of instruments of promotion of renewable energies: A transaction-cost perspective. Ecological Economics 62, 77–92.

Fischedick, M., Schaeffer, R., Adedoyin, A., Akai, M., Bruckner, T., Clarke, L., Krey, V., Savolainen, I., Teske, S., Ürge-Vorsatz, D., Wright, R., 2011. Mitigation Potential and Costs, in: Edenhofer, O., Pichs-Madruga, R., Sokona, Y., Seyboth, K., Matschoss, P., Kadner, S., Zwickel, T., Eickemeier, P., Hansen, G., Schlömer, S., von Stechow, C. (Eds.), IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation. Cambridge University Press, Cambridge, UK and New York, NY, USA.

Fischer, C., Preonas, L., 2010. Combining policies for renewable energy: Is the whole less than the sum of its parts? Resource for the Future Discussion Paper.

Fouquet, D., Johansson, T.B., 2008. European renewable energy policy at crossroads—Focus on electricity support mechanisms. Energy Policy 36, 4079–4092.

Friedman, 2012. Consumer-Friendly and Environmentally-Sound Electricity Rates for the Twenty-First Century (No. v 1.1). Goldman School of Public Policy, Berkeley, CA, USA.

Goldemberg, J., 2004. The Case for Renewable Energies.

Green, R., Vasilakos, N., 2010. Market behaviour with large amounts of intermittent generation. Energy Policy 38, 3211–3220.

Hoff, T., Margolis, R., 2004. Are Photovoltaic Systems Worth More to Residential Consumers on Net Metered Time-of-Use Rates? Presented at the Solar 2004 Conference, Portland, OR, p. 14.

Hoff, T., Norris, B., Wayne, D., 2003. Potential Economic Benefits of Distributed Photovoltaics to the Nevada Power Company. Clean Power Research, Napa. CA.

Hoff, T., Perez, R., Braun, G., Kuhn, M., Norris, B., 2006. The Value of Distributed Photovoltaics to Austin Energy and the City of Austin. Clean Power Research, Napa. CA.

Hoffert, M.I., Caldeira, K., Benford, G., Criswell, D.R., Green, C., Herzog, H., Jain, A.K., Kheshgi, H.S., Lackner, K.S., Lewis, J.S., Lightfoot, H.D., Manheimer, W., Mankins, J.C., Mauel, M.E., Perkins, L.J., Schlesinger, M.E., Volk, T., Wigley, T.M.L., 2002. Advanced Technology Paths to Global Climate Stability: Energy for a Greenhouse Planet. Science 298, 981–987.

Hummon, M., Denholm, P., Margolis, R., 2012. Impact of photovoltaic orientation on its relative economic value in wholesale energy markets. Progress in Photovoltaics: Research and Applications n/a–n/a.

IPCC (Intergovernmental Panel on Climate Change), 2007. Climate Change 2007: Mitigation of Climate Change: Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, UK.

Ito, K., 2012. Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing (EI @ Hass No. WP 210R). Energy Institute at Haas, Berkeley, CA.

Itron, Inc, 2012. CPUC California Solar Initiative; 2010 Impact Evaluation; Addendum to Final Report (Submitted to Southern California Edison and the California Public Utilities Commission's Energy Division). Davis, CA.

Jacobsen, H.K., Zvingilaite, E., 2010. Reducing the market impact of large shares of intermittent energy in Denmark. Energy Policy 38, 3403–3413.

Jacobsson, S., Bergek, A., 2004. Transforming the energy sector: the evolution of technological systems in renewable energy technology. Industrial and Corporate Change 13, 815–849.

Joskow, P.L., 2008. Capacity payments in imperfect electricity markets: Need and design. Utilities Policy 16, 159–170.

Kahn, E., 2008. Avoidable Transmission Cost is a Substantial Benefit of Solar PV. The Electricity Journal 21, 41–50.

Kelly, H., Weinberg, C., 1993. Utility strategies for using renewables, in: Johansson, T., Kelly, H., Reddy, A., Williams, R. (Eds.), Renewable Energy: Sources for Fuels and Electricity. Island Press.

Klaassen, G., Miketa, A., Larsen, K., Sundqvist, T., 2005. The impact of R&D on innovation for wind energy in Denmark, Germany and the United Kingdom. Ecological Economics 54, 227–240.

Lamont, A.D., 2008a. Assessing the long-term system value of intermittent electric generation technologies. Energy Economics 30, 1208–1231.

Lamont, A.D., 2008b. Assessing the long-term system value of intermittent electric generation technologies. Energy Economics 30, 1208–1231.

Lauber, V., 2004. REFIT and RPS: options for a harmonised Community framework. Energy Policy 32, 1405–1414.

Lipp, J., 2007. Lessons for effective renewable electricity policy from Denmark, Germany and the United Kingdom. Energy Policy 35, 5481–5495.

Loiter, J.M., Norberg-Bohm, V., 1999. Technology policy and renewable energy: public roles in the development of new energy technologies. Energy Policy 27, 85–97.

Margolis, R.M., Kammen, D.M., 1999. Underinvestment: The Energy Technology and R&D Policy Challenge. Science 285, 690 –692.

Menanteau, P., Finon, D., Lamy, M.-L., 2003. Prices versus quantities: choosing policies for promoting the development of renewable energy. Energy Policy 31, 799–812.

Micali, V., Heunis, S., 2010. Statistical Methods for Time-of-Use Classifications. Presented at the Industrial & Commercial Use of Energy 2010, Cape Town, South Africa, p. 8.

Midttun, A., Gautesen, K., 2007. Feed in or certificates, competition or complementarity? Combining a static efficiency and a dynamic innovation perspective on the greening of the energy industry. Energy Policy 35, 1419–1422.

Mills, A., Phadke, A., Wiser, R., 2010. Exploration of Resource and Transmission Expansion Decisions in the Western Renewable Energy Zone Initiative (Report No. LBNL-3077E). Lawrence Berkeley National Laboratory, Berkeley, CA, USA.

Mills, A., Wiser, R., 2010. Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power.

Mills, A., Wiser, R., 2012. Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California (Report No. LBNL-5445E). Lawrence Berkeley National Laboratory, Berkeley, CA, USA.

Mills, A., Wiser, R., Barbose, G., Golove, W., 2008. The impact of retail rate structures on the economics of commercial photovoltaic systems in California. Energy Policy 36, 3266–3277.

Mills, A., Wiser, R., Porter, K., 2009. The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies (LBNL Report No. LBNL-1471E). Lawrence Berkeley National Laboratory, Berkeley, CA, USA.

Mitchell, C., Bauknecht, D., Connor, P.M., 2006. Effectiveness through risk reduction: a comparison of the renewable obligation in England and Wales and the feed-in system in Germany. Energy Policy 34, 297–305.

Mitchell, C., Sawin, J., Pokharel, G.R., Kammen, D.M., Wang, Z., Fifita, S., Jaccard, M., Langniss, O., Lucas, H., Nadai, A., Trujillo Blanco, R., Usher, E., Verbruggen, A., Wüstenhagen, R., Yamaguchi, K., 2011. Policy, Financing and Implementation, in: Edenhofer, O., Pichs-Madruga, R., Sokona, Y., Seyboth, K., Matschoss, P., Kadner, S., Zwickel, T., Eickemeier, P., Hansen, G., Schlömer, S., von Stechow, C. (Eds.), IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation. Cambridge University Press, Cambridge, UK and New York, NY, USA, p. 134 pp.

Mondol, J.D., Yohanis, Y.G., Norton, B., 2007. The impact of array inclination and orientation on the performance of a grid-connected photovoltaic system. Renewable Energy 32, 118–140.

MRW and Associates, 2007. Solar PV and Retail Rate Design (Unpublished draft report for the California Energy Commission). MRW and Associates, Oakland, CA.

Müller, S., Brown, A., Ölz, S., 2011. Renewable Energy: Policy Considerations for Deploying Renewables (Information Paper). International Energy Agency, Paris, France.

Nemet, G.F., Kammen, D.M., 2007. U.S. energy research and development: Declining investment, increasing need, and the feasibility of expansion. Energy Policy 35, 746–755.

Newell, S., Spees, K., Pfeifenberger, J., Mudge, R., DeLucia, M., Carlton, R., 2012. ERCOT Investment Incentives and Resource Adequacy. The Brattle Group, prepared for the Electric Reliability Council of Texas.

NHA, 2010. The Use of Large Scale Pumped Hydro; Energy Storage for Grid Reliability, Renewable Integration and Renewable Load Shifting. National Hydropower Association.

Nicolosi, M., 2012. The Economics of Renewable Electricity Market Integration. An Empirical and Model-Based Analysis of Regulatory Frameworks and their Impacts on the Power Market (PhD Thesis).

NOAA, 2012. Unedited Local Climatological Data (2004). National Oceanic and Atmospheric Administration's National Climatic Data Center, Washington, DC, USA.

NOAA (National Oceanic and Atmospheric Administration), 2012. National Climatic Data Center (NCDC) website.

NREL, 2007. National Solar Radiation Database 1991-2005 Update: User's Manual (Technical Report No. NREL/TP-581-41364). National Renewable Energy Laboratory (NREL), Golden, CO.

NREL, 2010. Renewable Resource Data Center: PVWatts [WWW Document]. Natl. Renew. Energy Lab. URL http://www.nrel.gov/rredc/pvwatts/

O'Donnell, C., Baumstark, P., Nibler, V., Corfee, K., Sullivan, K., 2009. Renewable Energy Cost of Generation Update (Prepared for the California Energy Commission) (Report No. CEC-500-2009-084). KEMA, Inc., Oakland, CA, USA.

O'Mahoney, A., Denny, E., 2011. The merit order effect of wind generation in the Irish electricity market, in: 30th IAEE/USAEE North American Conference. Washington, D.C.

Ong, S., 2012. White Paper: The Value of Grid-Connected Photovoltaics in Michigan (Michigan Review Draft). National Renewable Energy Laboratory (NREL), Golden, CO.

Ong, S., Denholm, P., Doris, E., 2010. The Impacts of Commercial Electric Utility Rate Structure Elements on the Economics of Photovoltaic Systems (Technical Report No. NREL/TP-6A2-46782). National Renewable Energy Laboratory, Golden, CO, USA.

Oren, S.S., 2005. Ensuring generation adequacy in competitive electricity markets. Electricity Deregulation: Choices and Challenges 388–414.

Palmer, K., Paul, A., Woerman, M., Steinberg, D.C., 2011. Federal policies for renewable electricity: Impacts and interactions. Energy Policy 39, 3975–3991.

Parmesano, H., Kury, T.J., 2010. Implications of Carbon Cap-and-Trade for Electricity Rate Design, with Examples from Florida. The Electricity Journal 23, 27–36.

Passey, R., Watt, M., Outhred, H., Spooner, T., Snow, M., 2007. Study of Grid-connect Photovoltaic Systems - Benefits, Opportunities, Barriers and Strategies (FINAL REPORT for The Office of Energy Western Australian Government.). The University of New South Wales.

Pearce, J.M., Harris, P.J., 2007. Reducing greenhouse gas emissions by inducing energy conservation and distributed generation from elimination of electric utility customer charges. Energy Policy 35, 6514–6525.

Pietruszkiewicz, J., 2012. Black and Veatch. Renewable Energy Costs. Presented at the California Energy Commission. Retail Rate and Cost Issues with Renewable Development Workshop, May 22, 2012.

Pollock, A., Shumikina, E., 2010. How to Induce Customers to Consume Energy Efficiently: Rate Design Options and Methods (Research Papers No. 2010-03). National Regulatory Research Institute, Silver Spring, MD, USA.

Potter, C., Lew, D., McCaa, J., Cheng, S., Eichelberger, S., Grimit, E., 2008. Creating the Dataset for the Western Wind and Solar Integration Study (U.S.A.). Wind Engineering 32, 325–338.

Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities (No. FERC order No. 888), 1996. . Federal Energy Regulatory Commission, Washington, DC.

R.W. Beck, 2009. Distributed Renewable Energy Operating Impacts and Valuation Study (Prepared for Arizona Public Service). Arizona Public Service.

Rábago, K.R., Libby, L., Harvey, T., 2012. Designing Austin Energy's Solar Tariff Using a Distributed PV Value Calculator. Presented at the Proceedings of World Renewable Energy Forum 2012, Denver, CO, USA.

Rabe, B.G., 2007. Beyond Kyoto: Climate Change Policy in Multilevel Governance Systems. Governance 20, 423–444.

Reiss, P.C., White, M.W., 2005. Household Electricity Demand, Revisited. The Review of Economic Studies 72, 853–883.

Ringel, M., 2006. Fostering the use of renewable energies in the European Union: the race between feed-in tariffs and green certificates. Renewable Energy 31, 1–17.

Roscoe, A.J., Ault, G., 2010. Supporting high penetrations of renewable generation via implementation of real-time electricity pricing and demand response. IET Renewable Power Generation 4, 369 –382.

Rose, J., Chapman, S., Rose, G., Jackson, R., Weidman, J., Keyes, J., Fox, K., Culley, T., Quinlan, M., Varnando, L., Murchie, C., 2009. Freeing the Grid: Best and Worst Practices in State Net Metering Policies and Interconnection Standards; 2009 Edition. Network for New Energy Choices, New York, NY.

Sáenz de Miera, G., del Río González, P., Vizcaíno, I., 2008a. Analysing the impact of renewable electricity support schemes on power prices: The case of wind electricity in Spain. Energy Policy 36, 3345–3359.

Sáenz de Miera, G., del Río González, P., Vizcaíno, I., 2008b. Analysing the impact of renewable electricity support schemes on power prices: The case of wind electricity in Spain. Energy Policy 36, 3345–3359.

Schmalensee, R., 2012. Evaluating Policies to Increase Electricity Generation from Renewable Energy. Review of Environmental Economics and Policy 6, 45–64.

Schwartz, L., Porter, K., Mudd, C., Fink, S., Rogers, J., Bird, L., Hogan, M., Lamont, D., Kirby, B., 2012. Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge. Western Governors' Association.

Sensfuß, F., Ragwitz, M., Genoese, M., 2008. The merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany. Energy Policy 36, 3086–3094.

Solar Alliance, 2008. Opening Comments of The Solar Alliance, The California Solar Energy Industries Association, The Vote Solar Initiative, GreenVolts, and Recurrent Energy, Inc. on the Issues Regarding Phase 2 of Tariff and Standard Contract Implementation for RPS Generators (Comments filed in Rulemaking 06-05-027). California Public Utilities Commission, San Francisco, CA.

Steggals, W., Gross, R., Heptonstall, P., 2011. Winds of change: How high wind penetrations will affect investment incentives in the GB electricity sector. Energy Policy 39, 1389–1396.

Stoft, S., 2002. Power System Economics: Designing Markets for Electricity, 1st ed. Wiley-IEEE Press.

Tsao, C.-C., Campbell, J.E., Chen, Y., 2011. When renewable portfolio standards meet cap-and-trade regulations in the electricity sector: Market interactions, profits implications, and policy redundancy. Energy Policy 39, 3966–3974.

US EIA, 2010. Updated Capital Cost Estimates for Electricity Generation Plants. U.S. Energy Information Administration, Office of Energy Analysis, Washington, DC, USA.

US EIA, 2011. Annual Energy Outlook 2011 with Projections to 2035. U.S. Energy Information Administration, Office of Energy Analysis, Washington, DC, USA.

US EIA, 2012a. Annual Energy Outlook 2012 with Projections to 2035. U.S. Energy Information Administration, Office of Energy Analysis, Washington, DC, USA.

US EIA, 2012b. Annual Electric Power Industry Report (Survey form No. EIA-861). U.S. Energy Information Administration, Washington, DC, USA.

VanGeet, O., Brown, E., Blair, T., McAllister, A., 2008. Solar San Diego: The Impact of Binomial Rate Structures on Real PV Systems; Preprint (No. NREL/CP-670-42923). National Renewable Energy Laboratory, Golden, CO.

Weather Underground, 2012. Historical Weather [WWW Document]. URL www.wunderground.com/history/

Weiss, J., Chang, J., Aydin, O., 2012. The Potential Impact of Solar PV on Electricity Markets in Texas (Prepared for the Solar Energy Industries Association and the Energy Foundation). The Brattle Group.

Weissman, S., Johnson, N., 2012. The Statewide Benefits Of Net-Metering In California & the Consequences of Changes to the Program. Center for Law, Energy & the Environment, University of California, Berkeley, Berkeley, CA, USA.

Wen, F.S., Wu, F.F., Ni, Y.X., 2004. Generation capacity adequacy in the competitive electricity market environment. International journal of electrical power & energy systems 26, 365–372.

Wilcox, S., Marion, W., 2008. Users Manual for TMY3 Data Sets (Technical Report No. NREL/TP-581-43156). National Renewable Energy Laboratory, Golden, CO, USA.

Williams, J.H., DeBenedictis, A., Ghanadan, R., Mahone, A., Moore, J., Morrow, W.R., Price, S., Torn, M.S., 2012. The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity. Science 335, 53–59.

Wiser, R., Mills, A., Barbose, G., Golove, W., 2007. The Impact of Retail Rate Structures on the Economics of Commercial Photovoltaic Systems in California (Report No. LBNL-63019). Lawrence Berkeley National Laboratory, Berkeley, CA, USA.

Woo, C.K., Horowitz, I., Moore, J., Pacheco, A., 2011. The impact of wind generation on the electricity spot-market price level and variance: The Texas experience. Energy Policy 39, 3939–3944.

Yamamoto, Y., 2012. Pricing electricity from residential photovoltaic systems: A comparison of feed-in tariffs, net metering, and net purchase and sale. Solar Energy 86, 2678–2685.

Appendix A. Retail Electricity Rates

The appendix is structured as follows. Appendix A contains the details of the retail electricity rates computed, including the breakdown of the volumetric adders for the flat and TOU rates, the rate components for the flat rate and TOU rates, the TOU period definitions, and residual revenue adder for the RTP rate. Appendix B contains tables which describe residential customer load and customer PV generation in terms of percentage distribution within TOU periods (for the TOU rate) and within wholesale price bins (for the RTP rate). Appendix C includes tables with the value of bill savings for each scenario and rate option.

Table A-1. Breakdown of volumetric adder for flat and TOU rates, for net metering and hourly netting ($/kWh)

	Description	Net Metering: T&D and misc.	Net Metering: Utility-owned generation	Net Metering: renewable adder	Net Metering: Total	Hourly Netting: T&D and misc.	Hourly Netting: Utility-owned generation	Hourly Netting: renewable adder	Hourly Netting: Total
	Reference	$0.101	$0.004	$0.010	$0.115	$0.101	$0.004	$0.010	$0.115
Isolation scenarios	high PV	$0.109	$0.004	$0.022	$0.134	$0.106	$0.004	$0.022	$0.132
Isolation scenarios	high wind	$0.101	$0.004	$0.020	$0.125	$0.101	$0.004	$0.020	$0.125
Isolation scenarios	high C price	$0.101	$0.004	$0.010	$0.115	$0.101	$0.004	$0.010	$0.115
Isolation scenarios	high NG price	$0.101	$0.004	$0.010	$0.115	$0.101	$0.004	$0.010	$0.115
Isolation scenarios	low NG price	$0.101	$0.004	$0.010	$0.115	$0.101	$0.004	$0.010	$0.115
	33% RE Mix	$0.105	$0.004	$0.031	$0.140	$0.104	$0.004	$0.031	$0.139
RE Mix integration scenarios	High Storage	$0.105	$0.017	$0.031	$0.153	$0.104	$0.017	$0.031	$0.152
RE Mix integration scenarios	Demand Response	$0.105	$0.004	$0.031	$0.140	$0.104	$0.004	$0.031	$0.139
RE Mix integration scenarios	Increased CSP / decreased PV	$0.103	$0.004	$0.034	$0.140	$0.102	$0.004	$0.034	$0.140

In Table A-1, the volumetric adder is broken down into three components which recover the transmission, distribution, and miscellaneous costs ($C_{T\&D}$), utility-owned gerneration costs (C_{uog}), and utility renewable costs (C_{RE}). For the rates where fixed costs are recovered with a fixed customer charge (the two-part tariff), the adder is simply the sum of the utility-owned generation and the renewable adder and all other rate components are the same as for the principal analyses.

Table A-2. R_{adder}, R_{gen}, and R_{total} for flat rate, under net metering and hourly netting ($/kWh)

		Net Metering			Hourly Netting		
	description	R_{gen}	R_{adder}	R_{total}	R_{gen}	R_{adder}	R_{total}
	Reference	$0.064	$0.115	$0.179	$0.064	$0.115	$0.179
Isolation scenarios	high PV	$0.060	$0.134	$0.194	$0.058	$0.132	$0.190
Isolation scenarios	high wind	$0.058	$0.125	$0.183	$0.058	$0.125	$0.183
Isolation scenarios	high C price	$0.079	$0.115	$0.194	$0.079	$0.115	$0.194
Isolation scenarios	high NG price	$0.073	$0.115	$0.187	$0.073	$0.115	$0.187
Isolation scenarios	low NG price	$0.056	$0.115	$0.171	$0.056	$0.115	$0.171
	33% RE Mix	$0.052	$0.140	$0.192	$0.051	$0.139	$0.190
RE Mix integration scenarios	High Storage	$0.049	$0.153	$0.203	$0.049	$0.152	$0.201
RE Mix integration scenarios	Demand Response	$0.041	$0.140	$0.181	$0.040	$0.139	$0.179
RE Mix integration scenarios	Increased CSP / decreased PV	$0.045	$0.140	$0.186	$0.045	$0.140	$0.185

For all scenarios considered, except for the "33% RE mix with demand response" scenario, the peak season was found to be June through September. For the "33% RE mix with demand response" scenario, the peak season was found to be May through October. The low season is the remainder of the months for each scenario.

The total flat rate, **R_{total}**, is the equivalent for the scenarios that assume a lower price cap with a capacity cost adder.

Table A-3. Time-of-use period definitions for peak season

		Business Day			Non-business day	
	description	Low	Mid	High	Low	Mid
	Reference	0 - 9 and 23 - 0	9 - 13 and 19 - 23	13 - 19	0 - 13 and 22 - 0	13 - 22
Isolation scenarios	high PV	1 - 15	15 - 18 and 21 - 1	18 - 21	0 - 18 and 23 - 0	18 - 23
	high wind	0 - 8 and 23 - 0	8 - 14 and 18 - 23	14 - 18	0 - 14 and 21 - 0	14 – 21
	high C price	0 - 9 and 23 - 0	9 - 13 and 19 - 23	13 - 19	0 - 12 and 23 - 0	12 – 23
	high NG price	0 - 9 and 23 - 0	9 - 13 and 19 - 23	13 - 19	0 - 13 and 22 - 0	13 – 22
	low NG price	0 - 9 and 23 - 0	9 - 13 and 19 - 23	13 - 19	0 - 13 and 22 - 0	13 – 22
	33% RE Mix	0 - 13	13 - 17 and 21 - 0	17 - 21	0 - 17 and 22 - 0	17 – 22
RE Mix integration scenarios	High Storage	1 - 11	11 - 17 and 23 - 1	17 - 23	5 - 15 and 0 - 5	15 – 0
	Demand Response	1 - 10	10 - 17 and 22 - 1	17 - 22	0 - 17 and 23 - 0	17 – 23
	Increased CSP / decreased PV	0 - 10	10 - 16 and 21 - 0	16 - 21	0 - 16 and 22 - 0	16 – 22

Note: For Table A-3 and tables following, 0=midnight, 12=noon.

The period definitions are the same for the two-part tariffs.

Table A-4. Time-of-use period definitions for off-peak season

	description	Business Day Low	Business Day Mid	Business Day High	Non-business day Low	Non-business day Mid
	Reference	0 - 6 and 23 – 0	6-23	-	23 - 9	11 - 23 and 9 - 11
Isolation scenarios	high PV	1 - 5 and 9 – 15	5 - 9 and 15 - 17 and 23 - 1	17 - 23	0 - 16	16 - 0
Isolation scenarios	high wind	0 - 6 and 23 – 0	6 - 23	-	0 - 9 and 23 - 0	9 - 23
Isolation scenarios	high C price	0 - 6 and 23 – 0	6 - 23	-	0 - 9 and 23 - 0	9 - 23
Isolation scenarios	high NG price	0 - 6 and 23 – 0	6 - 23	-	1 - 9 and 23 - 1	9 - 23
Isolation scenarios	low NG price	0 - 6 and 23 – 0	6 - 23	-	8 - 10 and 23 - 8	10 - 23
	33% RE Mix	0 – 5	5 - 16 and 22 - 0	16 - 22	1 - 16 and 0 - 1	16 - 0
RE Mix integration scenarios	High Storage	0 – 5	10 - 16 and 22 - 0 and 5 - 10	16 - 22	2 - 16 and 0 - 2	16 - 0
RE Mix integration scenarios	Demand Response	1 – 5	5 - 16 and 22 - 1	16 - 22	0 - 16	16 - 0
RE Mix integration scenarios	Increased CSP / decreased PV	0 – 6	6 - 16 and 22 - 0	16 - 22	0 - 15	15 - 0

Table A-5. Time-of-use rates for all periods for peak season ($/kWh)

		Net Metering			Hourly Netting		
	description	Low	Mid	High	Low	Mid	High
	Reference	$0.145	$0.164	$0.493	$0.145	$0.164	$0.493
Isolation scenarios	high PV	$0.158	$0.204	$0.701	$0.155	$0.203	$0.713
	high wind	$0.151	$0.184	$0.604	$0.151	$0.184	$0.603
	high C price	$0.157	$0.186	$0.497	$0.157	$0.186	$0.497
	high NG price	$0.152	$0.175	$0.502	$0.152	$0.175	$0.502
	low NG price	$0.138	$0.154	$0.485	$0.138	$0.153	$0.485
	33% RE Mix	$0.162	$0.186	$0.572	$0.160	$0.185	$0.578
RE Mix integration scenarios	High Storage	$0.182	$0.198	$0.417	$0.180	$0.196	$0.418
	Demand Response	$0.173	$0.200	$0.252	$0.171	$0.198	$0.252
	Increased CSP / decreased PV	$0.160	$0.173	$0.455	$0.159	$0.172	$0.456

Table A-6. Time-of-use rates for off-peak season ($/kWh)

		Net Metering			Hourly Netting		
	description	Low	Mid	High	Low	Mid	High
	Reference	$0.142	$0.150	-	$0.142	$0.150	-
Isolation scenarios	high PV	$0.156	$0.166	$0.171	$0.153	$0.164	$0.169
	high wind	$0.145	$0.153	-	$0.145	$0.153	-
	high C price	$0.154	$0.166	-	$0.154	$0.166	-
	high NG price	$0.148	$0.158	-	$0.148	$0.158	-
	low NG price	$0.136	$0.142	-	$0.136	$0.142	-
	33% RE Mix	$0.159	$0.164	$0.167	$0.158	$0.163	$0.166
RE Mix integration scenarios	High Storage	$0.173	$0.178	$0.180	$0.172	$0.176	$0.179
	Demand Response	$0.163	$0.170	$0.175	$0.161	$0.169	$0.174
	Increased CSP / decreased PV	$0.163	$0.170	$0.175	$0.158	$0.018	$0.018

Table A-7. The RTP's residual revenue adder, R_{RRA} ($/kWh)

	description	Net Metering	Hourly Netting
	Reference	$0.085	$0.085
Isolation scenarios	high PV	$0.096	$0.094
	high wind	$0.088	$0.088
	high C price	$0.079	$0.079
	high NG price	$0.082	$0.082
	low NG price	$0.089	$0.089
	33% RE Mix	$0.094	$0.093
RE Mix integration scenarios	High Storage	$0.110	$0.108
	Demand Response	$0.100	$0.099
	Increased CSP / decreased PV	$0.090	$0.089

Note: The variable portion of the RTP rate is equal to the hourly wholesale electricity price.

Retail rates: Side Analyses

The flat and TOU rates for the two-part tariff rate structure are similar to that of the principal analyses, except that the adder portion of the rate is equal to the sum of the utility-owned generation and the renewable adder. The variable portion of the RTP rate is simply the wholesale electricity price. The fixed portions of the two-part tariffs were not calculated, as they are not relevant to the bill savings from PV and could be recovered at different rates for different customers (as for the HOOP rates, for example).

The following tables present the TOU and RTP rate assuming a $1/kWh wholesale price cap and capacity cost volumetric adder. The flat rate is the same as for the principal analysis.

Table A-8. Time-of-use period definitions for peak season , assuming a lower wholesale price cap and a capacity cost adder.

	Business Day			Non-business day	
Description	**Low**	**Mid**	**High**	**Low**	**Mid**
Reference	0-9 and 23-0	9-13 and 19-23	13-19	0-13 and 22-0	13-22
33% RE Mix	0-13	13-17 and 22-0	17-22	0-17 and 22-0	17-22

Table A-9. Time-of-use period definitions for off-peak season, assuming a lower wholesale price cap and a capacity cost adder

	Business Day			Non-business day	
description	**Low**	**Mid**	**High**	**Low**	**Mid**
Reference	0-6 and 23-0	6-23	-	0-9 and 23-0	9-23
33% RE Mix	0-5	5-16 and 22-0	16-22	0-16	16-0

Table A-10. Time-of-use rates for all periods for peak season ($/kWh), assuming a lower wholesale price cap and a capacity cost adder.

	Net Metering			Hourly Netting		
description	Low	Mid	High	Low	Mid	High
Reference	0.165	0.184	0.274	0.165	0.184	0.274

33% RE Mix	0.181	0.200	0.280	0.179	0.198	0.278

Table A-11. Time-of-use rates for all periods for off-peak season ($/kWh), assuming a lower wholesale price cap and a capacity cost adder.

	Net Metering			Hourly Netting		
description	Low	Mid	High	Low	Mid	High
Reference	0.162	0.170	-	0.162	0.170	-
33% RE Mix	0.178	0.183	0.186	0.176	0.182	0.185

Table A-12. The RTP's residual revenue adder, R_{RRA} ($/kWh), assuming a lower wholesale price cap and a capacity cost adder.

description	Net Metering	Hourly Netting
Reference	0.115	0.115
33% RE Mix	0.129	0.127

Appendix B. Residential load and PV generation distributions.

In this section of the appendix, the wholesale price profile, residential customer load and customer PV generation is classified by TOU period and wholesale price bin (for RTP).

Table B-1. TOU period distribution (percent of hours in each TOU period)

		High Season			Low Season		
	description	Low	Mid	High	Low	Mid	High
	Reference	16.0%	11.5%	5.8%	22.1%	44.6%	0.0%
Isolation scenarios	high PV	21.6%	8.9%	2.9%	33.0%	22.2%	11.4%
	high wind	15.9%	13.6%	3.9%	22.1%	44.6%	0.0%
	high C price	15.2%	12.4%	5.8%	22.1%	44.6%	0.0%
	high NG price	16.0%	11.5%	5.8%	22.1%	44.6%	0.0%
	low NG price	16.0%	11.5%	5.8%	23.0%	43.7%	0.0%
	33% RE Mix	20.6%	8.9%	3.9%	23.5%	31.7%	11.4%
RE Mix integration scenarios	High Storage	16.0%	11.5%	5.8%	23.5%	31.7%	11.4%
	Demand Response	16.5%	12.3%	4.8%	21.4%	33.5%	11.4%
	Increased CSP / decreased PV	17.3%	11.2%	4.8%	24.6%	30.7%	11.4%

Table B-2. Aggregate residential load distribution, by TOU period (percent of annual customer load in each TOU period)

		High Season			Low Season		
	description	Low	Mid	High	Low	Mid	High
	Reference	13.2%	15.5%	8.4%	15.9%	47.0%	-
Isolation scenarios	high PV	20.5%	12.1%	4.6%	26.9%	21.7%	14.3%
	high wind	13.6%	17.9%	5.7%	15.9%	47.0%	-
	high C price	12.2%	16.6%	8.4%	15.9%	47.0%	-
	high NG price	13.2%	15.5%	8.4%	15.9%	47.0%	-
	low NG price	13.2%	15.5%	8.4%	16.8%	46.1%	-
	33% RE Mix	18.7%	12.3%	6.2%	18.3%	30.4%	14.1%
RE Mix integration scenarios	High Storage	13.5%	14.9%	8.8%	18.3%	30.4%	14.1%
	Demand Response	14.3%	14.8%	7.4%	16.9%	32.1%	14.4%
	Increased CSP / decreased PV	15.0%	14.5%	7.6%	18.8%	29.9%	14.1%

Note: Assumes customer does not have a behind-the-meter PV system. Customer load is adjusted for the demand response scenario, as per section 4.2.6.1.

Table B-3. Average annual residential customer bill distribution, by TOU period (percent of annual bill in each TOU period)

		High Season			Low Season		
	Description	Low	Mid	High	Low	Mid	High
	Reference	10.7%	14.2%	23.1%	12.6%	39.3%	-
Isolation scenarios	high PV	16.0%	13.1%	17.8%	20.3%	19.3%	13.5%
	high wind	11.3%	18.0%	18.7%	12.6%	39.4%	-
	high C price	9.9%	15.9%	21.5%	12.6%	40.1%	-
	high NG price	10.7%	14.5%	22.5%	12.6%	39.7%	-
	low NG price	10.7%	13.9%	23.8%	13.3%	38.3%	-
	33% RE Mix	15.6%	11.9%	18.9%	15.2%	25.7%	12.7%
RE Mix integration scenarios	High Storage	12.0%	14.2%	18.8%	15.7%	26.4%	13.0%
	Demand Response	13.7%	16.1%	10.7%	15.2%	29.9%	14.3%
	Increased CSP / decreased PV	12.9%	13.4%	18.9%	16.1%	25.9%	12.8%

Note: Assumes customer does not have a behind-the-meter PV system. Aggregate residential load is used. Customer load is adjusted for the demand response scenario, as per section 4.2.6.1.

Table B-4. PV generation distribution, by TOU period (percent of annual PV generation in each TOU period)

		High Season			Low Season		
	description	Low	Mid	High	Low	Mid	High
	Reference	7.3%	18.4%	14.7%	1.2%	58.4%	-
Isolation scenarios	high PV	32.8%	7.1%	0.5%	47.8%	10.5%	1.3%
	high wind	7.8%	22.2%	10.4%	1.2%	58.4%	-
	high C price	5.6%	20.0%	14.7%	1.2%	58.4%	-
	high NG price	7.3%	18.4%	14.7%	1.2%	58.4%	-
	low NG price	7.3%	18.4%	14.7%	2.9%	56.7%	-
	33% RE Mix	24.8%	13.6%	1.9%	17.0%	39.0%	3.6%
RE Mix integration scenarios	High Storage	15.3%	23.1%	1.9%	17.0%	39.0%	3.6%
	Demand Response	14.3%	22.8%	1.5%	17.3%	39.9%	4.2%
	Increased CSP / decreased PV	13.8%	22.3%	4.3%	15.2%	40.8%	3.6%

Note: Mean customer PV generation profile is used.

Table B-5. Residential customer PV generation compensation distribution, by TOU period (percent of annual PV compensation in each TOU period, assuming net metering)

		High Season			Low Season		
	description	Low	Mid	High	Low	Mid	High
	Reference	5.2%	14.9%	35.8%	0.8%	43.3%	-
Isolation scenarios	high PV	31.6%	8.8%	2.2%	45.4%	10.6%	1.4%
Isolation scenarios	high wind	5.7%	19.8%	30.4%	0.8%	43.3%	-
Isolation scenarios	high C price	4.1%	17.1%	33.5%	0.8%	44.4%	-
Isolation scenarios	high NG price	5.2%	15.3%	34.9%	0.8%	43.7%	-
Isolation scenarios	low NG price	5.2%	14.6%	36.7%	2.0%	41.5%	-
	33% RE Mix	23.1%	14.6%	6.4%	15.6%	36.9%	3.5%
RE Mix integration scenarios	High Storage	14.9%	24.5%	4.3%	15.7%	37.1%	3.5%
RE Mix integration scenarios	Demand Response	13.9%	25.6%	2.1%	15.9%	38.3%	4.2%
RE Mix integration scenarios	Increased CSP / decreased PV	12.5%	21.8%	11.1%	13.7%	37.5%	3.4%

Note: Mean customer PV generation profile is used.

Table B-6. Wholesale price distribution, by wholesale price bin (percent of hours in each wholesale price bin)

		Wholesale price ($/kWh)			
	description	0-0.05	0.05-0.10	0.10-1	1-10
	Reference	44.5%	54.7%	0.4%	0.5%
Isolation scenarios	high PV	63.8%	34.9%	0.8%	0.4%
	high wind	46.1%	52.9%	0.5%	0.5%
	high C price	0.0%	90.0%	9.5%	0.5%
	high NG price	30.3%	66.0%	3.2%	0.5%
	low NG price	89.8%	9.3%	0.4%	0.5%
	33% RE Mix	58.4%	40.5%	0.6%	0.5%
RE Mix integration scenarios	High Storage	45.7%	51.4%	2.5%	0.4%
	Demand Response	34.7%	54.6%	10.7%	0.0%
	Increased CSP / decreased PV	53.0%	46.1%	0.4%	0.5%

Table B-7. Residential load distribution, by wholesale price bin (percent of annual customer load in each wholesale price bin)

		Wholesale price ($/kWh)			
	description	0-0.05	0.05-0.10	0.10-1	1-10
	Reference	35.6%	62.7%	0.7%	0.9%
Isolation scenarios	high PV	53.1%	44.5%	1.5%	0.9%
	high wind	37.8%	60.4%	0.9%	1.0%
	high C price	0.0%	84.7%	14.3%	0.9%
	high NG price	21.8%	72.4%	4.9%	0.9%
	low NG price	84.6%	13.7%	0.7%	0.9%
	33% RE Mix	48.3%	49.5%	1.1%	1.0%
RE Mix integration scenarios	High Storage	36.4%	59.2%	3.5%	0.9%
	Demand Response	27.0%	56.7%	16.3%	0.0%
	Increased CSP / decreased PV	43.4%	54.7%	0.9%	1.1%

Note: Assumes customer does not have a behind-the-meter PV system. Aggregate residential load is used, and customer load is adjusted for the demand response scenario, as per section 4.2.6.1.

Table B-8. Average annual residential customer bill distribution, by wholesale price bin (percent of annual bill in each wholesale price bin)

		Wholesale price ($/kWh)			
	description	0-0.05	0.05-0.10	0.10-1	1-10
	Reference	25.2%	50.1%	2.4%	22.4%
Isolation scenarios	high PV	37.6%	35.5%	3.4%	23.5%
	high wind	26.8%	47.7%	2.8%	22.8%
	high C price	0.0%	64.7%	15.6%	19.6%
	high NG price	15.2%	57.2%	6.4%	21.3%
	low NG price	62.1%	12.0%	2.5%	23.4%
	33% RE Mix	34.3%	39.0%	3.2%	23.5%
RE Mix integration scenarios	High Storage	27.5%	49.2%	5.5%	17.8%
	Demand Response	21.3%	52.5%	26.2%	0.0%
	Increased CSP / decreased PV	30.8%	42.9%	2.5%	23.8%

Note: Assumes customer does not have a behind-the-meter PV system. Aggregate residential net load is used. Customer load is adjusted for the demand response scenario, as per section 4.2.6.1.

Table B-9. Residential customer PV generation distribution, by wholesale price bin, based on average customer PV generation profile (percent of annual PV generation in each wholesale price bin).

		Wholesale price ($/kWh)			
	description	0-0.05	0.05-0.10	0.10-1	1-10
	Reference	15.3%	82.8%	0.9%	1.0%
Isolation scenarios	high PV	89.3%	10.2%	0.2%	0.1%
	high wind	16.3%	81.5%	1.2%	1.0%
	high C price	0.0%	80.2%	18.8%	1.0%
	high NG price	3.2%	89.4%	6.4%	1.0%
	low NG price	80.1%	18.0%	0.9%	1.0%
	33% RE Mix	71.7%	27.6%	0.3%	0.3%
RE Mix integration scenarios	High Storage	52.3%	44.7%	2.7%	0.3%
	Demand Response	39.6%	48.1%	12.3%	0.0%
	Increased CSP / decreased PV	51.4%	47.4%	0.6%	0.6%

Table B-10. Residential PV compensation distribution, based on average customer PV generation profile (percent of annual PV compensation in each wholesale price bin, assuming net metering)

		Wholesale price ($/kWh)			
	description	0-0.05	0.05-0.10	0.10-1	1-10
	Reference	10.9%	65.0%	2.9%	21.3%
Isolation scenarios	high PV	84.8%	11.0%	0.6%	3.5%
	high wind	11.4%	62.5%	3.6%	22.4%
	high C price	0.0%	61.6%	19.8%	18.5%
	high NG price	2.2%	69.6%	8.0%	20.1%
	low NG price	59.2%	15.5%	3.0%	22.3%
	33% RE Mix	63.4%	27.2%	1.4%	8.0%
RE Mix integration scenarios	High Storage	46.4%	44.0%	4.4%	5.2%
	Demand Response	33.6%	47.6%	18.8%	0.0%
	Increased CSP / decreased PV	41.3%	41.8%	2.1%	14.8%

Appendix C. Value of bill savings from residential PV

The median value of bill savings from behind-the-meter residential PV for all rates and PV-to-load ratios are found in this appendix. The value of bill savings from PV does not change with PV-to-load ratio for net metering, and hence only one value is listed under net metering for each scenario and rate option.

Table C-1. Median value of bill Savings from PV under flat rate ($\$/kWh\ of\ PV\ generation$).

			hourly netting		
	description	net metering	25% PV-to-load	50% PV-to-load	75% PV-to-load
	Reference	0.179	0.157	0.135	0.125
Isolation scenarios	high PV	0.194	0.159	0.123	0.103
Isolation scenarios	high wind	0.183	0.161	0.139	0.129
Isolation scenarios	high C price	0.194	0.175	0.155	0.145
Isolation scenarios	high NG price	0.187	0.167	0.146	0.136
Isolation scenarios	low NG price	0.171	0.149	0.125	0.114
	33% RE Mix	0.192	0.160	0.126	0.109
RE Mix integration scenarios	High Storage	0.203	0.169	0.135	0.116
RE Mix integration scenarios	Demand Response	0.181	0.155	0.127	0.112
RE Mix integration scenarios	Increased CSP / decreased PV	0.186	0.158	0.129	0.114

Table C-2. Median value of bill Savings from PV under TOU rate ($\$/kWh\ of\ PV\ generation$).

	description	net metering	hourly netting 25% PV-to-load	hourly netting 50% PV-to-load	hourly netting 75% PV-to-load
	Reference	0.201	0.177	0.150	0.136
Isolation scenarios	high PV	0.164	0.137	0.109	0.094
Isolation scenarios	high wind	0.206	0.182	0.155	0.141
Isolation scenarios	high C price	0.217	0.194	0.169	0.156
Isolation scenarios	high NG price	0.211	0.186	0.161	0.147
Isolation scenarios	low NG price	0.193	0.167	0.140	0.125
	33% RE Mix	0.173	0.148	0.120	0.105
RE Mix integration scenarios	High Storage	0.187	0.158	0.128	0.112
RE Mix integration scenarios	Demand Response	0.178	0.152	0.126	0.112
RE Mix integration scenarios	Increased CSP / decreased PV	0.176	0.153	0.127	0.113

Table C-3. Median value of bill savings from PV under RTP rate $(\$/kWh\ of\ PV\ generation)$.

	Description	net metering	hourly netting 25% PV-to-load	50% PV-to-load	75% PV-to-load
	Reference	0.181	0.164	0.144	0.132
Isolation scenarios	high PV	0.142	0.121	0.099	0.087
	high wind	0.187	0.169	0.149	0.137
	high C price	0.198	0.182	0.164	0.153
	high NG price	0.190	0.174	0.155	0.144
	low NG price	0.172	0.154	0.133	0.122
	33% RE Mix	0.152	0.133	0.111	0.099
RE Mix integration scenarios	High Storage	0.171	0.148	0.123	0.109
	Demand Response	0.167	0.146	0.122	0.109
	Increased CSP / decreased PV	0.164	0.146	0.125	0.113

Bill Savings: Side Analyses

Table C-4. Median value of bill savings from PV under flat rate $(\$/kWh\ of\ PV\ generation)$.

	Description	net metering	hourly netting 25% PV-to-load	50% PV-to-load	75% PV-to-load
Two-part tariff	Reference	0.075	0.074	0.076	0.080
	33% RE Mix	0.084	0.076	0.068	0.064
Price cap with cap cost adder	Reference	0.179	0.155	0.128	0.113
	33% RE Mix	0.192	0.160	0.125	0.107

Table C-5. Median value of bill savings from PV under TOU rate $(\$/kWh\ of\ PV\ generation)$**.**

	Description	net metering	hourly netting 25% PV-to-load	hourly netting 50% PV-to-load	hourly netting 75% PV-to-load
Two-part tariff	Reference	0.097	0.094	0.092	0.092
	33% RE Mix	0.064	0.062	0.060	0.058
Price cap with cap cost adder	Reference	0.187	0.161	0.133	0.117
	33% RE Mix	0.186	0.155	0.123	0.105

Table C-6. Median value of bill savings from PV under RTP rate $(\$/kWh\ of\ PV\ generation)$**.**

	Description	net metering	hourly netting 25% PV-to-load	hourly netting 50% PV-to-load	hourly netting 75% PV-to-load
Two-part tariff	Reference	0.096	-	-	-
	33% RE Mix	0.058	-	-	-
Price cap with cap cost adder	Reference	0.183	0.159	0.132	0.117
	33% RE Mix	0.180	0.151	0.121	0.104

Note: There is no hourly netting rate for RTP with the two-part tariff, since there is no volumetric adder for this rate.

Appendix D. Bill Savings from RTP with Net Metering, Reference Scenario

PV generation is fairly concentrated at times when wholesale prices are higher than average. Using the output from the capacity investment and dispatch model, the PV generation-weighted average wholesale price is 38% higher than the average wholesale price, in the median case for the sample, even though peak prices occur several hours after peak PV generation. However, the bill savings with RTP are not being compared to the average wholesale price, but to the flat rate. The flat rate is the residential load-weighted average wholesale price[105] (plus an adder, as per equations 3 and 4 in the Chapter 4), and residential load is also fairly concentrated when wholesale prices are high. Specifically, residential load starts to ramp up to its peak as at times when prices spike to very high levels (at 4 or 5 pm); this can be seen in Figure 43 on page 110 in the top left quadrant. This results in the PV generation-weighted average wholesale price only being 3.7% higher than the residential load-weighted average wholesale price (in the median case).

The bill savings under RTP is *less than* 3.7% due to the fixed cost recovery through volumetric adders. The mathematical intuition for this is in the equations below. The equations calculate the ratio of bill savings with RTP to bill savings with the flat rate. The numerator in the expression labeled 'method #1' is simply the sum over all hours of the PV generation times the RTP rate, and the denominator is simply the sum over all hours of the PV generation times the flat rate (what is in the brackets in the denominator is simply equal to the flat rate, as per equations 1 and 2 in the text). I multiply the term by unity to rewrite the expression in a different form in the expression labeled 'method #2'. In #2, the numerator is the PV generation-weighted average wholesale price plus the RTP adder, and the denominator is the residential load-weighted average wholesale price plus the flat adder. Given that the PV generation-weighted average wholesale price is greater than the residential load wholesale price, and the RTP adder is less than the flat adder, the resulting fraction is always less than the 3.7% ratio (the PV generation-weighted wholesale price over the residential load-weighted wholesale price).

This ratio is calculated using method #1 and #2 for each customer in my sample in the attached spreadsheet. All calculations are done in the spreadsheet. The median ratio of bill savings with RTP to bill savings with flat rate is 1.012.

$$\frac{Value\ of\ Bill\ Savings\ with\ RTP}{Value\ of\ Bill\ Savings\ with\ Flat\ rate} =$$

$$\frac{\sum_h \left(g_h \cdot (p_h + R_{adder,RTP}) \right)}{\sum_h g_h \cdot \left(\frac{\sum_h \left(\left(L_{h,res} - G_{h,res\ PV} \right) \cdot \left(1 - r_{h,uog} - r_{h,util\ RE} \right) \cdot p_h \right)}{\sum_h \left(L_{h,res} - G_{h,res\ PV} \right)} + R_{adder,flat} \right)} \cdot \frac{1/\sum_h g_h}{1/\sum_h g_h}$$

[105] The weighting is actually to the portion of the residential load that is purchased on the wholesale market.

$$= \frac{\frac{\sum_h g_h \cdot p_h}{\sum_h g_h} + R_{adder,RTP}}{\frac{\sum_h \left(\left(L_{h,res} - G_{h,res\,PV} \right) \cdot \left(1 - r_{h,uog} - r_{h,util\,RE} \right) \cdot p_h \right)}{\sum_h \left(L_{h,res} - G_{h,res\,PV} \right)} + R_{adder,flat}}$$

The notation is similar to that of the main text, where g_h is the customer's PV generation in hour h, p_h is wholesale price in hour h, $R_{adder,RTP}$ is the RTP adder, $L_{h,res}$ is total residential load in hour h, $G_{h,res\,PV}$ is total residential PV generation in hour h, $\left(1 - r_{h,uog} - r_{h,util\,RE}\right)$ is the percentage of residential load purchased in the wholesale market in hour h, and $R_{adder,flat}$ is the flat rate adder.