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Electricity Bill Savings from Residential Photovoltaic Systems: Sensitivities to Changes in Future Electricity Market Conditions

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Environmental Energy Technologies Division

January 2013

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Executive Summary

Overview

Customer-sited photovoltaic (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. Given the multitude of potential changes to retail rates and PV compensation mechanisms in the future, however, understanding how such changes might impact the value of bill savings from PV is critical for policymakers, regulators, utilities, the solar industry, and potential PV owners, i.e., any stakeholder interested in understanding uncertainties in and potential changes to the long-term customer economics of PV.

This scoping study investigates the impact of, and interactions among, three key sources of uncertainty in the future value of bill savings from customer-sited PV, focusing in particular on residential customers. 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.

- Electricity Market Scenarios: We investigate the impact of a range of electricity market scenarios on retail electricity prices and rate structures, and the resulting effects on the value of bill savings from PV. 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.
- Retail Rate Structures: We examine the bill savings from PV with time-invariant, flat residential retail rates, as well as with time-varying retail rates, including time-of-use (TOU) rates and real-time pricing (RTP). In addition, we explore a flat rate with increasing-block pricing (IBP).[1]
- Net Metering and PV Compensation: We evaluate the bill savings from PV with net metering, as currently allowed in many states, as well as scenarios with hourly netting, a partial form of net metering.

The report seeks 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.

[1] We do not analyze rate options with higher fixed charges or standby rates, although this is an area of possible future research.

This scoping study is the first known effort to evaluate these types of interactions in a reasonably comprehensive fashion, though by no means have we considered every possible change to electricity market conditions, retail rate structures, or PV compensation mechanisms. It focuses solely on the private value of bill savings for residential PV and does not seek to quantify the broader social or economic cost or value of solar electricity. Our analysis applies assumptions based loosely on California's electricity market in a future year (2030); however, it is neither intended to forecast California's future market, nor are our conclusions intended to have implications specific only to the California market. That said, some of the findings are unique to our underlying assumptions, as described further within the main body of the report, along with other key limitations (see, in particular, Section 1.3 and Chapter 4).

Approach

To explore key uncertainties in the future value of bill savings for residential PV, we take the following approach:

1) We model the impacts of various electricity market scenarios on hourly wholesale market prices, using a simplified production-cost and capacity-expansion model. Using the California electricity market in 2030 as a loose case study, we model a reference scenario (which roughly assumes current levels of renewable generation); five Isolation scenarios that consider a single change to the reference scenario (15% PV penetration, 15% wind, $50/t carbon price,[2] and high and low natural gas price scenarios); a 33% renewable energy mix scenario; and three 33% renewable energy mix scenarios that include, respectively, a higher penetration of grid-level storage, demand response, and concentrating solar power (CSP) with storage. Table 1 (in Section 2.1) summarizes the assumptions for each of the scenarios.
2) Based on the hourly wholesale market prices calculated in the first step, and other assumptions specified in the report, we create three potential future retail rates for each electricity market scenario: flat, TOU, and RTP. The rate levels and structures are created using standard rate design principles and assuming full cost recovery of variable and fixed costs. The fixed costs are recovered through a volumetric adder, rather than with a fixed customer charge, but we recommend further research to analyze the impacts of the latter rate design option.
3) Finally, we calculate the value of bill savings from PV 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. We calculate bills with PV using two compensation mechanisms: (a) *net metering*, in which the customer receives full compensation at the prevailing retail rate for all PV-generated electricity; and (b) *hourly netting*, in which the customer's PV electricity generation during each hour displaces electricity consumed during that hour at prevailing retail rates, but PV generation that exceeds customer consumption during any hour is compensated at wholesale electricity market prices. Hourly netting arguably represents a practical lower bound for how utilities might compensate excess PV generation.

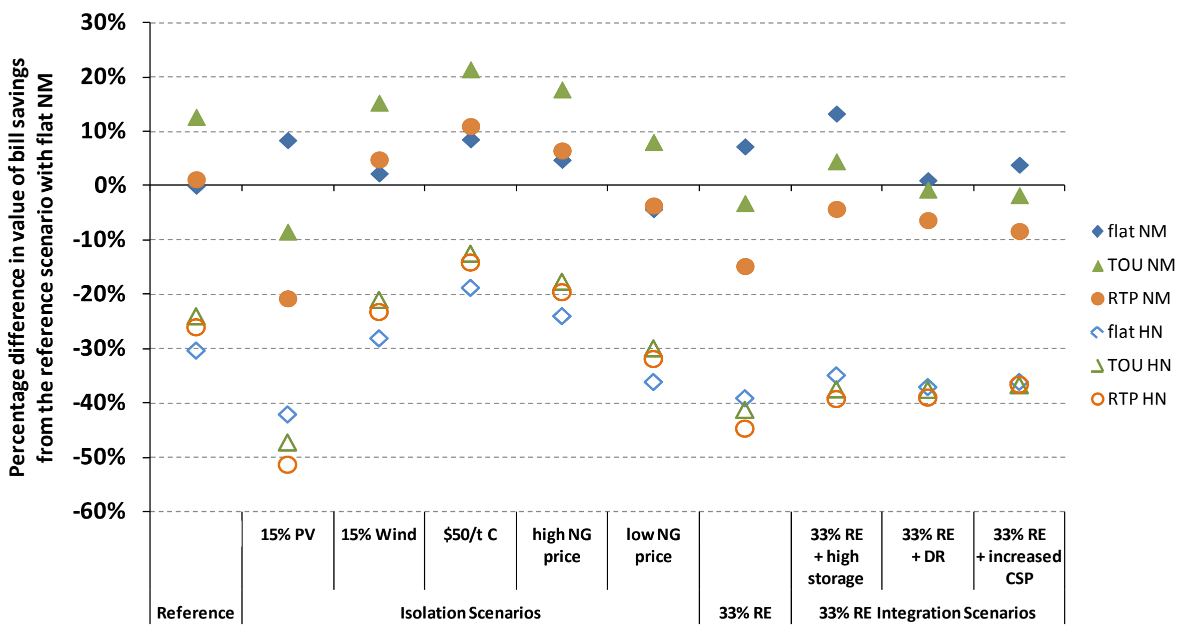
The last step described above is conducted for 226 California residential customers for whom data on hourly metered load are available. Simulated PV generation profiles for each customer are used to calculate bills with PV. The PV systems are sized to meet 75% of annual customer load in the

[2] All currency figures in this report are in real 2011 $US.

default case, which is slightly higher than the current average for California customers; some results for 25% and 50% PV-to-load ratios are also presented. The value of bill savings from residential PV is calculated as the difference in the annual bill with and without PV divided by the total annual kilowatt-hours generated by the PV system. Expressing the value of bill savings in terms of $/kWh allows for a direct comparison of electricity bills between residential customers with different loads and between alternate PV-to-load ratios.

Results and Conclusions

For our sample of 226 residential customers, we calculate each customer's value of bill savings from PV for each electricity market scenario, rate option, and PV compensation mechanism. The median value of bill savings across all customers for each of these permutations is summarized in Figure ES-1. In order to focus on the sensitivity of bill savings to each source of uncertainty, the bill savings in each case is expressed on a *relative* basis, as a percentage change from the bill savings with the flat rate and net metering under the reference scenario. The reference scenario assumes 0.3% of electricity from PV, 4.0% from wind, no CSP, and 7.4% from other renewables including geothermal, small hydro, and biogas, as well as no carbon price, no demand response, and a natural gas price based on the U.S. Energy Information Administration reference projection for 2030. This comparative baseline case is loosely modeled after residential rate structures common in the United States today (though it does not contain usage-based IBP that is currently the norm in California).



Notes: The figure presents bill savings under each permutation of electricity market scenario, rate structure, and PV compensation mechanism considered. Bill savings are shown in relative terms, as a percentage change from the reference scenario with flat rate and net metering (which corresponds to the 0% axis in the figure). NM = net metering; HN = hourly netting; RTP = real time pricing; TOU = time-of-use rates; C = carbon; NG = natural gas; RE = renewable energy; DR = demand response. A 75% PV-to-load ratio assumed for all customers.

Figure ES-1: Median value of bill savings from PV relative to the reference scenario with flat rate and net metering.

In general, the results show that 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. As such, simple assumptions that project a flat or increasing value of bill savings over time (in real terms) may not be accurate.

Specific key findings from the analysis are as follows:

- **Under electricity market scenarios with increased utility costs, the value of bill savings is higher than under the reference scenario when PV is compensated via a flat rate with net metering.** A number of the scenarios entail higher electricity costs than in the reference case, due to either the purchase costs of higher levels of renewable energy or increased costs for fossil generation in scenarios featuring a carbon price or higher natural gas prices. These conditions increase the retail rates needed to recover utility costs and thus also increase the value of bill savings for PV customers that can take advantage of flat rates with net metering. Under the particular scenarios considered, the bill savings from PV with a flat rate and net metering are 1% to 13% higher than under the reference case. The only exception is the isolation scenario with a low natural gas price, which yields lower electricity purchase costs for utilities and a 4% lower value of bill savings than under the reference case, for PV compensated via a flat retail rate and net metering.
- **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.
- **For electricity market scenarios <u>without</u> 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 (by 8-13% and 1%-7%, respectively), 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 (see the full report for details on this non-intuitive finding). Electricity systems with winter-evening peaks, where PV output does not correlate well with

peak wholesale electricity prices, would likely experience very different results than those presented here owing to our California-based assumptions.

- **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 a 1%-16% and 1%-27% 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.** Under the 15% PV penetration case, for example, the value of bill savings is 8% higher than in the reference case if PV is compensated under a flat rate with net metering (due to the higher costs associated with utility-scale PV generation) but is 8%-51% lower than in the reference case for the other five permutations of rate option and compensation mechanism (all of which have a time-varying component related to wholesale prices, which are lower than the reference scenario at times when PV generates). 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. Specifically, compared to the standard 33% renewable energy mix scenario, the value of bill savings from PV increases by up to 12%, 10%, and 8% with increased grid-level storage, demand response, or CSP with storage, respectively. 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.
- **IBP can lead to variations in the value of bill savings from PV that are even more significant than the variations associated with other rate options, compensation mechanisms, and electricity market scenarios.** IBP is a rate structure with usage tiers and increasing volumetric charges for consumption within each successive tier. Depending on the steepness of the usage-based price tiers, IBP can lead to a high value of bill savings from PV, especially for households with significant electricity consumption. The variation in value of bill savings across customers is

directly related to the range between the lowest- and highest-priced tier and hence dependent on rate design parameters. Using the rate design parameters specified in this report for a flat rate with IBP (which are based on the residential IBP rates currently employed in California), customers in the lowest consumption tiers receive a value of bill savings from PV that is up to 33% lower than for customers on the non-tiered flat rate with net metering, whereas customers in the highest tier receive a value of bill savings that is up to 102% higher than for customers on the non-tiered flat rate.

While these findings may be somewhat unique to the assumptions and setting used in the present research, they nonetheless 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. As policymakers, regulators, utilities, the solar industry, and potential PV owners consider the future economic attractiveness of residential PV—as well as appropriate rate design and PV compensation mechanisms—the interactions described in this report require further consideration and more detailed and location-specific analysis.

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Acronyms and Abbreviations

C	Carbon
CAISO	California Independent System Operator
CSP	Concentrating solar power
DR	Demand response
EIA	Energy Information Administration
FIT	Feed-in Tariff
IBP	Increasing-block pricing
IOU	Investor-owned utility
LCOE	Levelized cost of energy
NG	Natural gas
NREL	National Renewable Energy Laboratory
PG&E	Pacific Gas and Electric
PV	Photovoltaic
RE	Renewable energy
RPS	Renewable portfolio standard
RRR	Residual revenue requirement
RTP	Real-time pricing
SAM	System Advisor Model
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SPP	Statewide Pricing Pilot
T&D	Transmission and distribution
TOU	Time of use
WREZ	Western Renewable Energy Zone

1 Introduction

1.1 Overview

Customer-sited photovoltaic (PV) systems in the United States are often compensated at the customer's underlying retail electricity rate through net metering, one of the principal economic drivers for distributed PV deployment. Although specific policy design details vary from one state to another, net metering provides customers with PV bill credits for each unit of PV generation at the underlying retail rate, regardless of the temporal match between PV generation and customer load.[3]

From the customer's perspective, an economic evaluation of a behind-the-meter PV system compares the value of the monetary benefits accrued from the system to the cost of the system over its lifetime. Such calculations require assumptions about underlying retail rates and PV compensation mechanisms. To simplify the calculations, analysts, the solar industry, and others often assume that retail rate structures and PV compensation mechanisms will not change and that average retail prices will continue to increase (or remain constant), in real dollars, as they have in the past (e.g., Denholm et al., 2009; Drury et al., 2011; E3, 2011; SolarCity, 2012). These assumptions typically yield increasing estimates of the value of bill savings from customer-sited PV over time.[4] Given the multitude of potential changes to retail rates and PV compensation mechanisms in the future, however, understanding how such changes might impact the value of bill savings from PV is critical for policymakers, regulators, utilities, the solar industry, and potential PV owners, i.e., any stakeholder interested in understanding uncertainties in and potential changes to the long-term customer economics of PV.

This scoping study investigates the impact of, and interactions among, three key sources of uncertainty in the future value of bill savings from customer-sited PV, focusing in particular on residential customers. 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.

- <u>Electricity Market Scenarios:</u> We investigate the impact of a range of electricity market scenarios on retail electricity prices and rate structures, and the resulting effects on the value of bill savings from PV. 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.
- <u>Retail Rate Structures:</u> We examine the bill savings from PV with time-invariant, flat residential retail rates, as well as with time-varying retail rates, including time-of-use (TOU) rates and real-time pricing (RTP). In addition, we explore a flat rate with increasing-block pricing (IBP). We do not analyze rate options with higher fixed charges or standby rates, although this is an area of interest and possible future research.

[3] If the customer has a time-varying retail rate, the bill credit applied to PV generation is dependent on the timing of that generation.

[4] Given the long lifetime of PV systems, changes in retail rates and PV compensation mechanisms may impact both preexisting systems and those installed in the future.

- Net Metering and PV Compensation: We evaluate the bill savings from PV with net metering, as currently allowed in many states, as well as scenarios with hourly netting, a partial form of net metering.

The report seeks 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. Ignoring possibly significant changes in wholesale price profiles, retail rate structures, and PV compensation mechanisms can lead to an inaccurate view of the potential future economics of behind-the-meter PV.

This scoping study is the first known effort to evaluate these interactions in a reasonably comprehensive fashion. We 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.

1.2 Literature and context

This report 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 1). 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 we are 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., 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, 2008; 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 2.2).

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). Chief among 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, 2005a; 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.[5] 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 from the bottom in Figure 1. 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 (2005b), Borenstein (2008), and Bright Power Inc. et al. (2009), show that PV customers can often benefit from time-varying retail rates over flat rates.

[5] 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.

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.

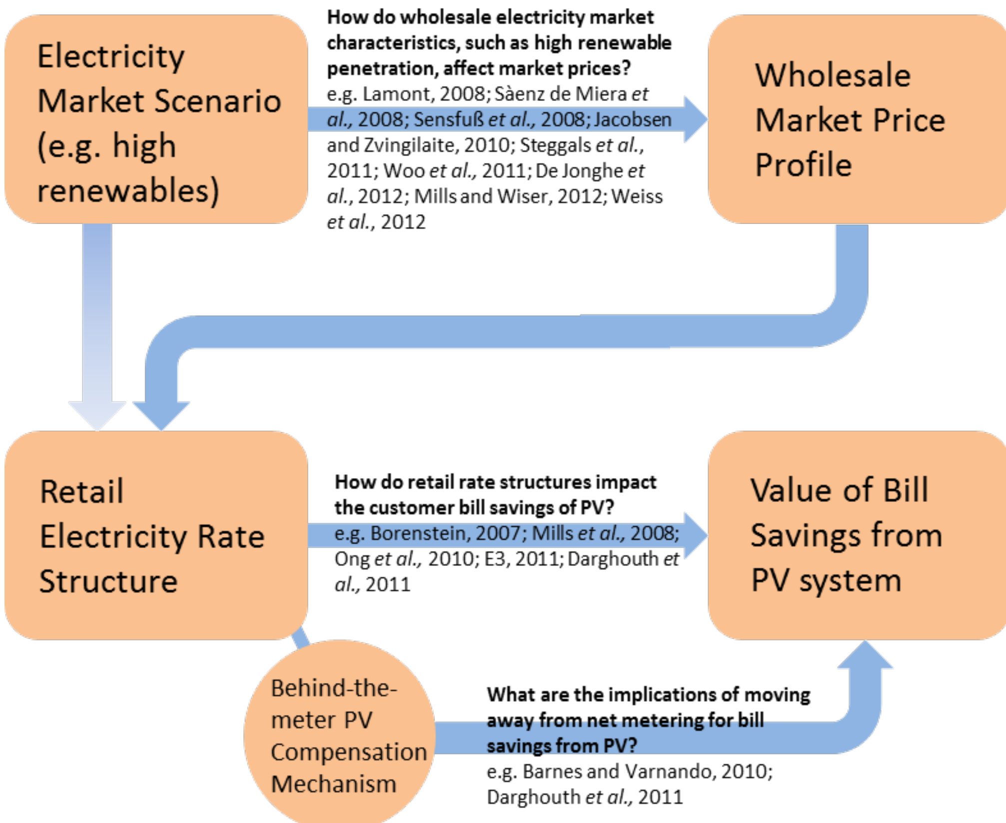

Figure 1: Mapping the Existing Literature

1.3 Basic approach and limitations

The principal objective of this study is to characterize – at a scoping level – 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, we take the following approach (which is detailed further in Chapter 2). First, we 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 (2012). We base a subset of our assumptions on the California electricity market in 2030. Second, based on the hourly wholesale market prices calculated in the first step, and with other assumptions specified later, we 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, we 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. We 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.[6]

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 Chapter 4. First, we 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 we seek to quantify the cost or value to the utility.[7] Second, our analysis is based on electricity market characteristics that are, in part, loosely based on California's electricity market 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, we 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). Finally, in order to maintain a tractable number of comparisons, our 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.

1.4 Report outline

Chapter 2 discusses the study's data and methods. Section 2.1 introduces the electricity market scenarios considered in this study. The reference scenario is based, in part, on current renewable generation in California. We 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. This discussion is followed in Section 2.2 by a description of the model used to simulate wholesale electricity prices in the scenarios. Section 2.3 outlines the methodology used for designing the retail rates, Section 2.4 describes and characterizes the customer load data and PV-generation data used in the study, and Section 2.5 details methods used to simulate customer electricity bills and calculate the value of PV-derived bill savings. Chapter 3 presents the core results of the analysis. Section 3.1 presents the results of the reference scenario, focusing on the impact of that scenario on retail electricity rates

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

[7] 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.

and the corresponding value of bill savings from PV for customers in our sample. Section 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 3.3 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 3.4 summarizes results for three variations on the 33% renewable penetration scenario, each intended to mitigate potential declines in the value of bill savings. Section 3.5 summarizes the core results. Chapter 4 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.

2 Data, Methods, and Assumptions

2.1 Electricity market scenarios

The analysis presented in this report considers a range of electricity market scenarios for year 2030. For all scenarios, California gross retail load is assumed to grow at an average of 1.2%/year through 2030,[8] 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[9]), 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 2.2). Distributed PV generation is assumed to be evenly distributed between residential and commercial sites for all scenarios.

The scenarios are summarized in Table 1. 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 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,[10] 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

[8] As per California Public Utilities Commission projections through 2020 from 2010 levels (CPUC, 2010).

[9] 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.

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

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, we 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.[11]

Table 1: 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
	High wind	0.3%	15.0%	0.0%	7.4%	50%	6.40	3.6	0	-0.001
	High C price	0.3%	4.0%	0.0%	7.4%	50%	6.40	3.6	50	-0.001
	High NG price	0.3%	4.0%	0.0%	7.4%	50%	7.97	3.6	0	-0.001
	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
RE Mix integration scenarios	High storage	8.1%	11.5%	3.5%	10.0%	30%	6.40	9.9	0	-0.001
	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, our three

[11] 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).

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.[12] 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, we 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, we used sites identified by the California 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). We 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, we 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[13]. 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.

[12] We assume that the majority of customers were under a flat rate in 2004 (the year that corresponds to our 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. We recognize that this is a simplistic approach to modeling demand response.

[13] In reality, however, distributed PV arrays may be oriented with any number of directions and tilts. However, our fixed orientation assumption is unlikely to create much error in our overall results (for more implications, see Section 2.4.2 and conclusions in Section 4).

2.2 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[14]). The resulting wholesale prices allow new conventional generation to recover exactly its fixed costs. Box 1 provides a discussion of how prices under an energy-only market design compare to market designs with a separate capacity market, and how these differences may impact the results of this study.

Box 1. Capacity payments under energy-only vs. capacity markets and the implications for retail electricity rates

Under an energy-only market design, as assumed in this study, 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

[14] 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).

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 2.3). 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.

Under an electricity market design with price caps and a separate capacity market, retail rates could differ, depending on the retail rate structure and the manner in which capacity market costs are passed through to retail rates.

- The flat rate would be equivalent to that under an energy-only market.
- With the TOU rate, if capacity costs are recovered through a volumetric adder that varies by TOU period, with the same period definitions as the generation cost component, then the rates would be largely equivalent to an energy-only market. If, instead, capacity costs were recovered through a flat volumetric adder, then this would reduce the spread in retail rates between peak and off-peak TOU periods, relative to what would occur under an energy-only market. More specifically, during TOU periods with low wholesale electricity prices, retail rates would be higher owing to the volumetric adder for capacity market costs. Conversely, during the TOU period with high wholesale electricity prices (i.e., the peak TOU period), retail rates would be lower, as the volumetric capacity cost adder would be more-than-offset by the reduction in average wholesale electricity prices during that period.
- Similarly, with the RTP rate, were capacity costs able to be allocated only to those hours where generation capacity was scarce (similar to a critical peak pricing rate, for instance), this would result in a similar set of rates as for the energy-only markets (where prices are only expected to spike in hours when generation capacity is scarce). Recovering capacity costs through a constant volumetric adder would result in higher rates during hours with lower wholesale electricity prices and lower rates during the hours that reach scarcity prices in the energy-only market.

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. See the conclusions, Chapter 4, for further discussion on the implications of the energy-only model assumption on the bill savings from behind-the-meter PV.

2.3 Determining residential retail rates from wholesale prices

2.3.1 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, can also be considered fixed costs because they too 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 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, we do not include this rate option in the current analysis presented in this report. Instead, we have chosen to focus on flat, TOU, and RTP rates that recover all costs through volumetric charges. We recommend future work on the impact of fixed charges on the economics of customer sited PV, and offer a number of potential implications on our results in the conclusions, Chapter 4.

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 2). We 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.[15] 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).[16] In the 33% RE with high storage scenario, we "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). We 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).[17] The T&D and miscellaneous costs

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

[16] 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).

[17] 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, we have maintained any existing cross-subsidies between the residential market and other customer segments.

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.[18] 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 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 2: 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.[19]
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.
RE purchase	Varies	C_{RE}	Weighted average of LCOEs for each generation type; for PV, consider wholesale purchases only (utility scale).

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

In this study, we 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 2 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 2 representing hourly load displaced by PV generation is compensated at the retail rate, and the purple/patterned shaded area in Figure 2 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

[18] 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; our 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.

[19] Although utilities sometimes sign long-term bilateral contracts with generators, reducing electricity purchases in the wholesale market, we do not consider these in this study. However, the prices negotiated in these bilateral contracts reflect market conditions, and hence would not impact our results significantly.

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 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.

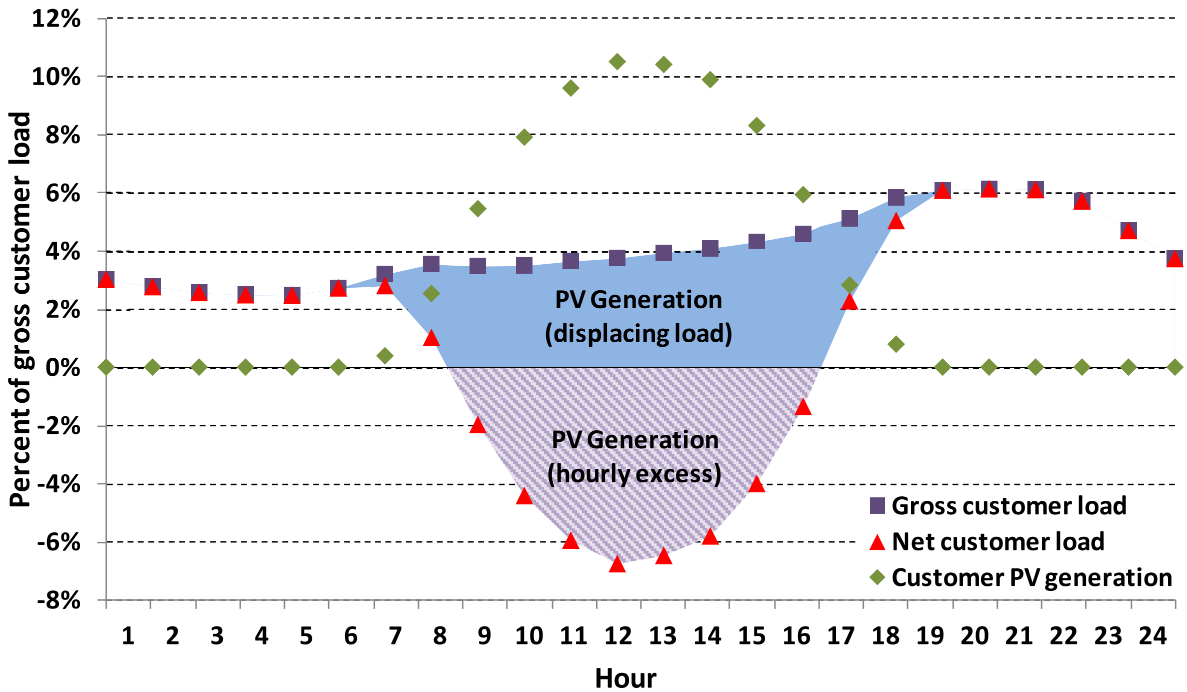

Figure 2: Example customer's gross load, net load, and PV generation, as a percentage of daily gross customer load, showing portion of PV generation that displaces load and the portion in excess of hourly load

Both residential PV compensation mechanisms (net metering and hourly netting) lead to reduced retail sales by utilities. Since residential rates are designed to ensure full cost recovery of both variable and fixed costs, reduced sales must lead to an increase in residential retail 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 2 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 2, summed over all customers). Compensating behind-the-meter PV generation with hourly netting therefore increases total net residential load (relative to net metering) since under hourly netting less PV generation is compensated at the retail rate than under net metering. When behind-the-meter PV generation is compensated via hourly netting, however, retail rates also must recover the additional utility cost of the compensation for the hourly excess electricity, since behind-the-meter exports are not sold directly in the wholesale market.

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.

Including any potential benefits to ratepayers beyond the energy value (such as displaced T&D costs, generation capacity credits, and reduced system losses) would result in higher PV compensation.

2.3.3 Flat rate

The first of the three retail rates we 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 2.3.1, 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[20] (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. The net residential load is 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 2 for net metering, and only the blue/solid shaded area for hourly netting). In summary:

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

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 we assume that the residential sector is responsible for residential T&D costs 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:

$$R_{adder} = \frac{C_{T\&D} + \left(C_{uog} + C_{RE}\right) \cdot r_{res}}{\sum_h \left(L_{h,res} - G_{h,res\,PV}\right)} \tag{2}$$

where $C_{T\&D}$ is the total T&D and miscellaneous costs for residential customers, 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).

[20] 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).

2.3.4 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. We 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 (3).

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

The numerator in equation (3) 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:

$$\sum_{j=1}^{2} \sum_{d \in S_j} \left(p_d - \overline{p_j}\right)^2 \tag{4}$$

where p_d is the mean daily price in day d and $\overline{p_j}$ is the mean daily price in S_j. We 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. We 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), we 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:

$$\sum_{i=1}^{3}\sum_{h\in T_i}(p_h-\overline{p_\iota})^2 \tag{5}$$

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. We then create a single weighted-average type day:

5) Let:

$$\boldsymbol{S}_{d,h} = \begin{cases} \bar{P}_{low} \ if \ h \in T_{low} \\ \bar{P}_{mid} \ if \ h \in T_{mid} \\ \bar{P}_{high} \ if \ h \in T_{high} \end{cases} \tag{6}$$

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.

6) Let:

$$\bar{\boldsymbol{S}}_h = \frac{\sum_d \boldsymbol{S}_{d,h}}{B} \tag{7}$$

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

7) 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).

2.3.5 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:

$$RRR = \left(C_{T\&D} + \left(C_{uog} + C_{RE}\right) \cdot r_{res}\right) - \sum_h \left(\left(L_{h,res} - G_{h,res\ PV}\right) \cdot P_h\right) \tag{8}$$

The RRR is assumed to be recovered through a volumetric charge for all residential customers,[21] which we term the residual revenue adder (R_{RRA}).

$$R_{RRA} = \frac{RRR}{\sum_h \left(L_{h,res} - G_{h,res\ PV}\right)} \tag{9}$$

[21] 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 our investigation, but it merits further exploration. See the conclusions (Section 4) for a discussion of how implementing a fixed customer charge could impact results.

2.3.6 Retail rate variations

Tiered rate

We 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 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.

$$t_{baseline} \cdot R_{gen,baseline} + t_2 \cdot R_{gen,2} + t_3 \cdot R_{gen,3} = R_{gen,flat} \tag{10}$$

$$\left(R_{gen,baseline} + R_{adder}\right) \cdot (1 + s_2) = R_{gen,2} + R_{adder} \tag{11}$$

$$\left(R_{gen,2} + R_{adder}\right) \cdot (1 + s_3) = R_{gen,3} + R_{adder} \tag{12}$$

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 3.

Table 3: 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.[22]

Elasticity of Demand

For the demand-response scenario, we 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.

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

[22] 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.

rates each month due to the tiered rate structure, the average rate in California in that year was \$0.1482/kWh (in 2011\$). We used this value as the anchor point from which we calculated the adjusted residential load. However, adjusting the residential load changes the retail rates—as per equations (1), (2), (3), and (9)—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.

2.4 Residential Customer Load and PV Generation Data

2.4.1 Customer interval load data

Our 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. Our 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 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 Darghouth et al. (2010). First, a common 12-month period was selected. The original data spanned 15 months, from May 19, 2003 to September 30, 2004. We 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.[23] 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. 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.

[23] 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 3 shows the customer load distribution for the customers in the final data set. Customers in our 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.

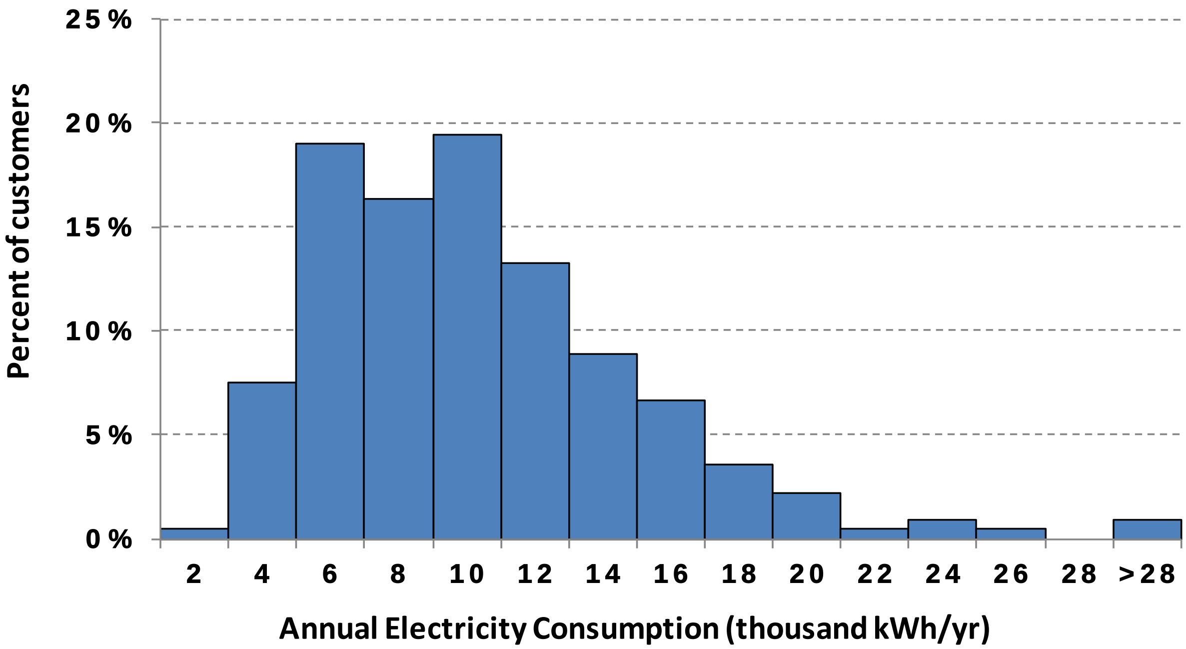

Figure 3: Annual load histogram for customers in our sample

The mean hourly load was calculated for each customer, as a percentage of total daily load. Figure 4 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 20), indicating that most customers in our sample have consumption patterns that are more heavily concentrated in the evening hours, when compared to the average residential customer in the CAISO. This small sample bias is likely to impact the value of bill savings for customers in our 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 we are not looking to recreate results that are specific to California.

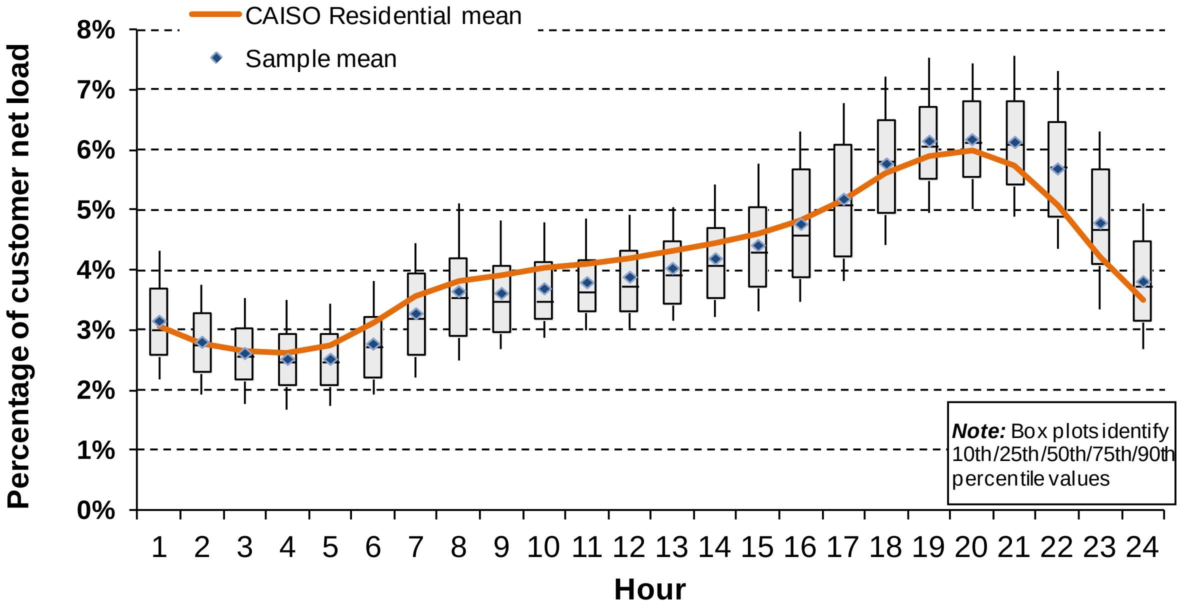

Figure 4: Percentage of consumption each hour for customers' mean day

2.4.2 Simulated customer PV generation data

Each customer within our load data sample was matched with simulated PV production data. For our analysis, we 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.[24] 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 our 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). We use 75% as the default PV-to-load ratio in our analysis, although a number of figures also show results for 25% and 50% PV-to-load ratios.

[24] 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 (Chapter 4).

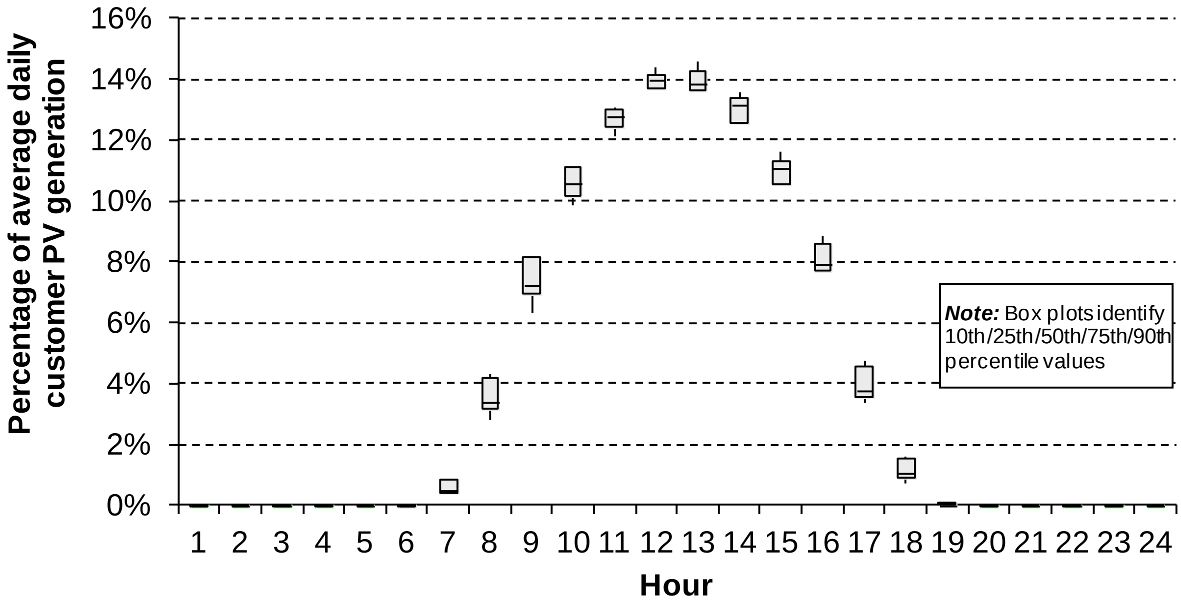

Figure 5: PV generation by hour, as a percentage of mean daily customer PV generation, using a mean PV generation profile for each customer

Figure 5 shows box-and-whisker plots of percentage of customer PV generation each hour in the mean day for customers in our 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 our 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 our analysis, rather than kWh/kW. 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.

2.4.3 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), we calculated net consumption (or net exports) as a percentage of gross hourly electricity for the mean day, shown in Figure 6, 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.

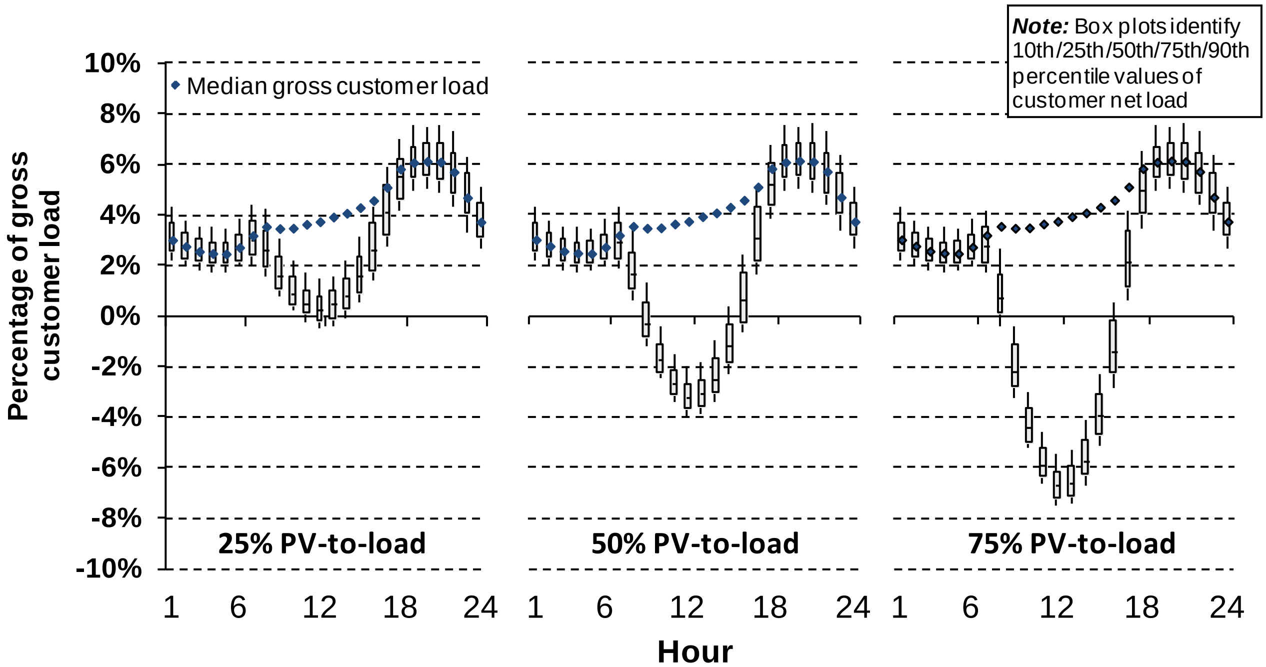

Figure 6: Net and gross hourly electricity for customers' mean day, as percentage of gross customer load

2.5 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.

2.5.1 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:

$$B_m = \sum_T \left(L_{m,T} - G_{m,T}\right) \cdot R_T \tag{13}$$

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:

$$B_a = \sum_h (p_h + R_{RRA}) \cdot (L_h - G_h) \tag{14}$$

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 (9)); L_h is gross customer load in hour h; and G_h is the customer's PV generation in hour h.

2.5.2 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:

$$B_a = \sum_h B_h \,;\; B_h = \begin{cases} (L_h - G_h) \cdot R_h \; if \; G_h < L_h \\ (L_h - G_h) \cdot p_h \; if \; G_h > L_h \\ 0 \; if \; G_h = L_h \end{cases} \tag{15}$$

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 2.3.3, 2.3.4, and 2.3.5, respectively).

2.5.3 Value of bill savings metric

To determine the value of the PV-derived utility bill savings to each customer, we 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. We express 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.

$$Value\ of\ Bill\ Savings = \frac{B_{a,noPV} - B_{a,PV}}{G_a} \tag{16}$$

where $B_{a,noPV}$ is the customer's annual bill without PV, $B_{a,PV}$ is the customer's annual bill with PV,[25] 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.

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

3 Results

This chapter presents the calculated residential retail rates and the corresponding value of bill savings for customers in our sample for the scenarios introduced in Section 2.1. First, we consider rates and value of bill savings for the reference scenario. We then present results for the isolation scenarios, using the reference as our baseline. Next, we 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, we 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.

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.

3.1.1 Retail rates (reference scenario)

i. Flat rate

As described in Section 2.3.3, 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 our analysis under the reference scenario, and the total flat retail rate (R_{total}), are shown in Table 4.

Table 4: Flat rate under reference scenario (in $/kWh).

R_{adder}	R_{gen}[26]	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 report; 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[27] 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

[26] 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.

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

model and the methods outlined in Section 2.3.4, TOU seasons and periods were determined for the reference case. The high-priced season was determined to be June-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 7, 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 5 contains the resulting retail rates for each period.

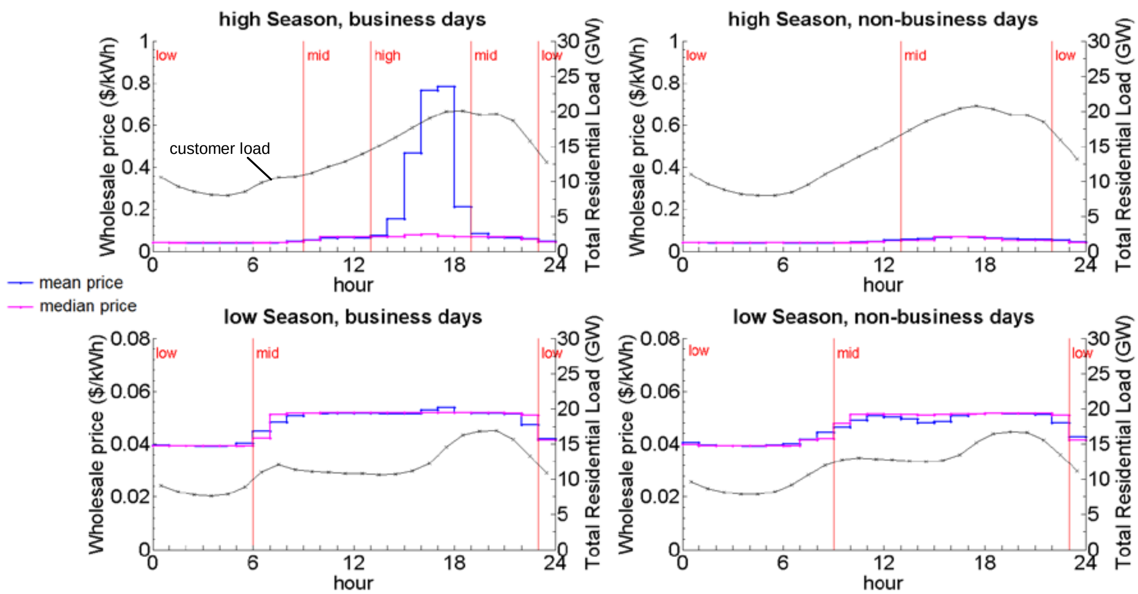

Figure 7: Mean and median wholesale electricity prices, aggregate residential load by TOU season, and TOU period definitions (reference scenario)[28]

Table 5: 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 7. Non-residential load peaks earlier in the day, and thus, with the low levels of renewable generation in the reference scenario, peak residential load in the high-priced season occurs at the tail end of the high TOU

[28] 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.

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 6. We 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 6: 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 7, using the PV generation profiles for our 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 7: 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.[29] As shown in Table 8, 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,

[29] This value is the same for net metering and hourly netting (when rounded to the nearest thousandth of a dollar).

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.[30]

Table 8: 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 9), 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.

Table 9: 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%

3.1.2 Value of bill savings (reference scenario)

We calculated annual utility bills for each customer from our 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.

[30] This is in contrast to most prevailing retail rates which distribute capacity costs equally through a volumetric adder.

Figure 8 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,[31] 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 is relatively low for two reasons: (a) although PV generates at high-priced times, most of the PV generation does not occur during high peak times, 83% is at wholesale prices of \$0.05-\$0.1/kWh, and (b) 47% of the value of bill savings is from the residual revenue adder, which is a fixed volumetric charge and hence not time dependent.

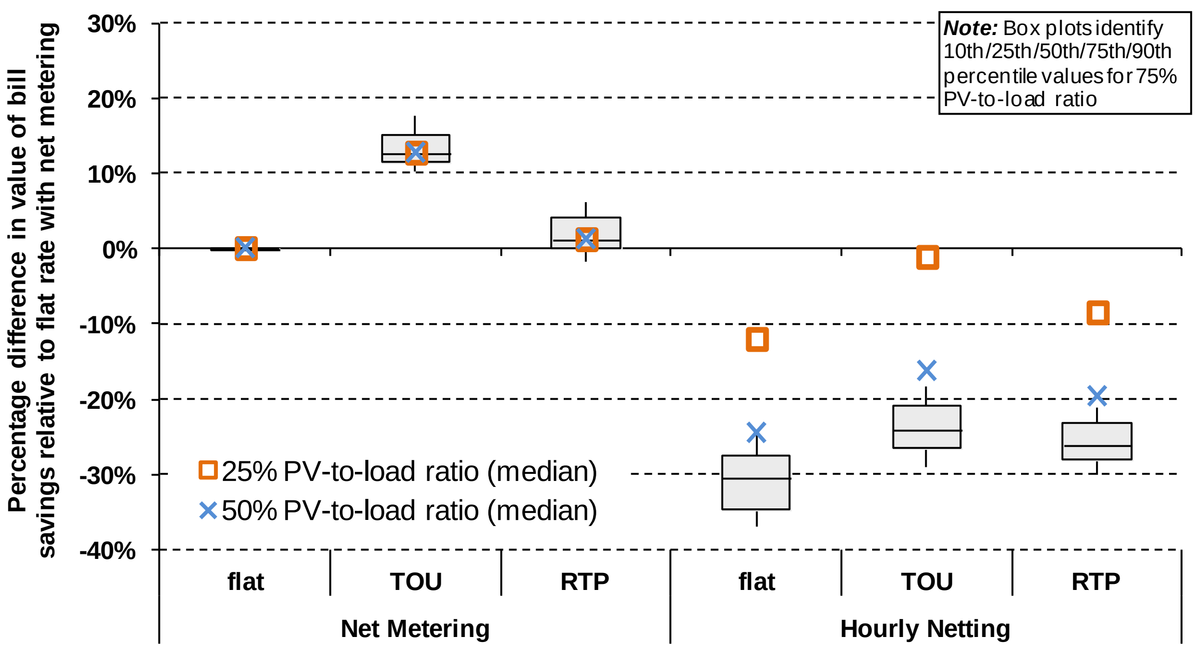

Figure 8: Value of bill savings relative to a flat rate with net metering (reference scenario)

With net metering, the variation in value of bill savings within each rate is due to the variation in temporal PV generation profiles in our sample. There is no variation in the value of bill savings for customers under 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

[31] 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.

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 8. 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%[32] (see Figure 5). 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.

[32] 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.

Box 2. Increasing block pricing for flat rate (reference scenario)

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. 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 in this report does not include tiering. We 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.[33] See Section 2.3.6 for the tiered rate design methodology used in this analysis. The tiered rates for the reference scenario are shown below in Table 10.

Table 10: Tiered flat rate for reference scenario ($/kWh)

	Tier 1	Tier 2	Tier 3
R_{total}	0.120	0.180	0.360

We computed utility bills for our 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 Darghouth et al. (2011), 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 9.

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.

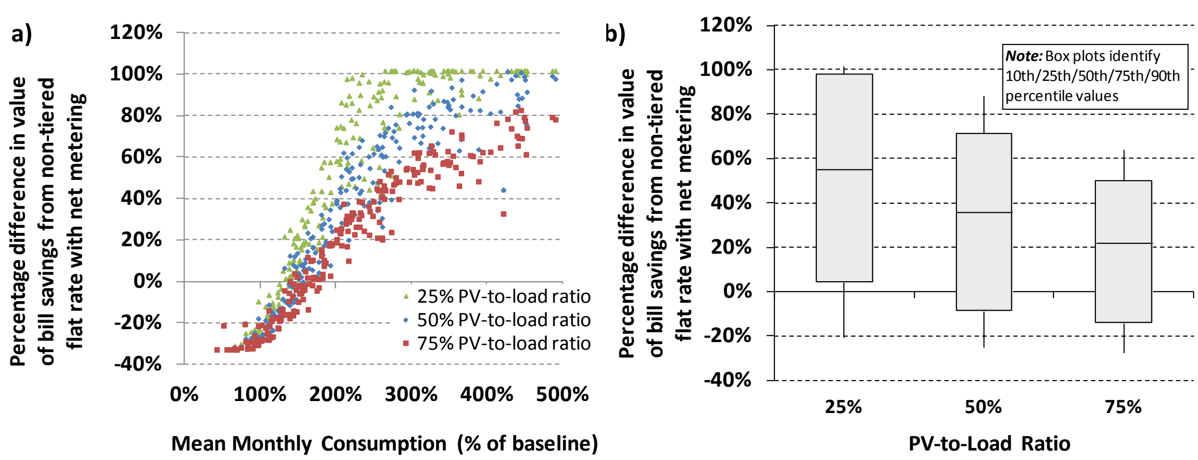

Figure 9: a) Value of bill savings for PV customers under the tiered flat rate as a function of customer gross electricity consumption, for three levels of PV-to-load ratios under the reference scenario. b) Box-and-

[33] 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.

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.

3.2 Isolation scenarios

Having analyzed the impact of various rate and PV compensation options on the reference scenario in the previous section, we now analyze the impact of specific changes in future electricity market scenarios. We developed five electricity market scenarios, each identical to the reference scenario except for one attribute, to isolate the impact of this change; we call these isolation scenarios. These scenarios are described in Section 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, we 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 Appendix A. Figure 10 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 3.5, 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 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.[34]

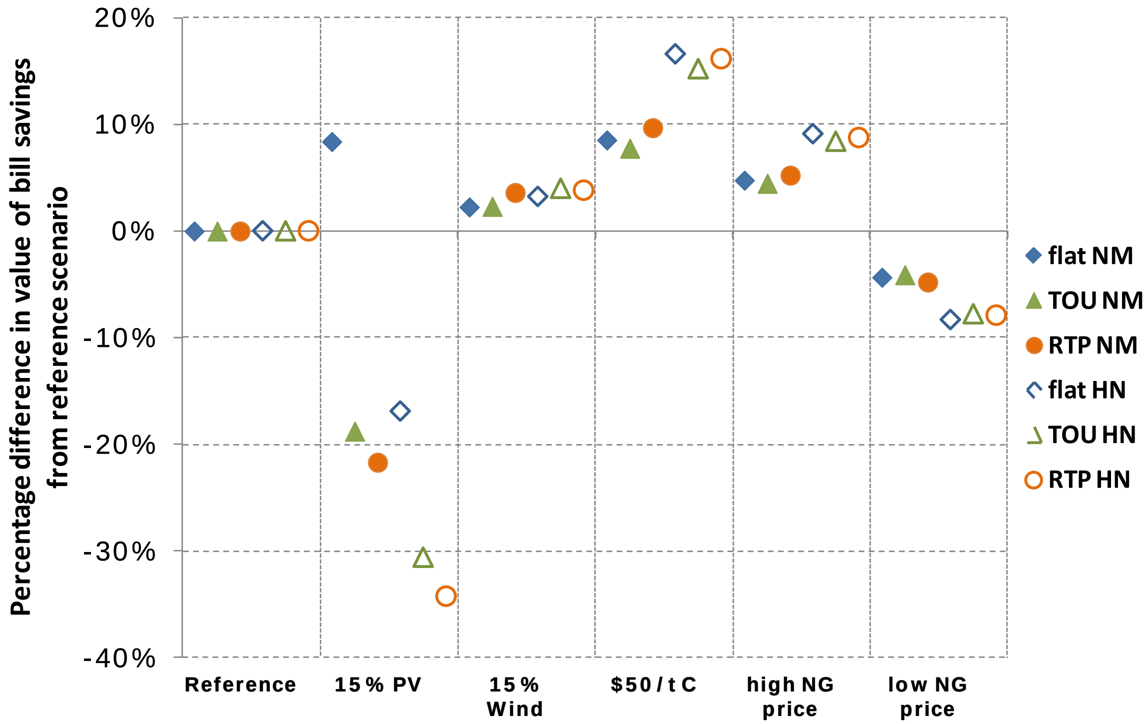

Figure 10: Value of bill savings for the isolation scenarios relative to the reference scenario's corresponding rate with net metering (NM) and hourly netting (HN). 75% PV-to-load ratio assumed.

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 we see in Figure 10, 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

[34] 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.

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 seems to be most sensitive to PV penetration. In Box 3, we investigate this further by quantifying how value of bill savings is impacted by increased levels of PV penetration.

Box 3: Impact of increasing PV penetrations on bill savings from PV

We 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 11, 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%). 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.

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 11. 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.

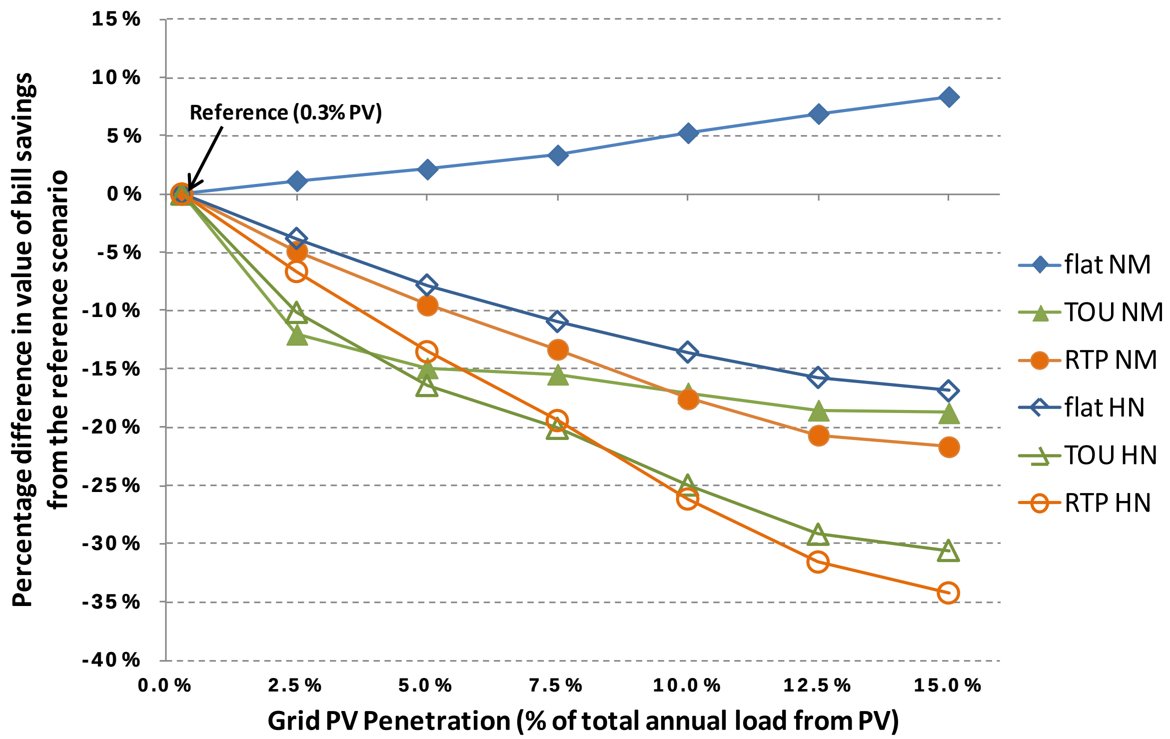

Figure 11: Value of bill savings from PV with increasing grid PV penetration levels, relative to the reference scenario's corresponding rate with net metering (NM) and hourly netting (HN). 75% PV-to-load ratio assumed.

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.

3.3 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. We 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.

3.3.1 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 11).[35]

Table 11: 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 12). 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.

[35] 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.

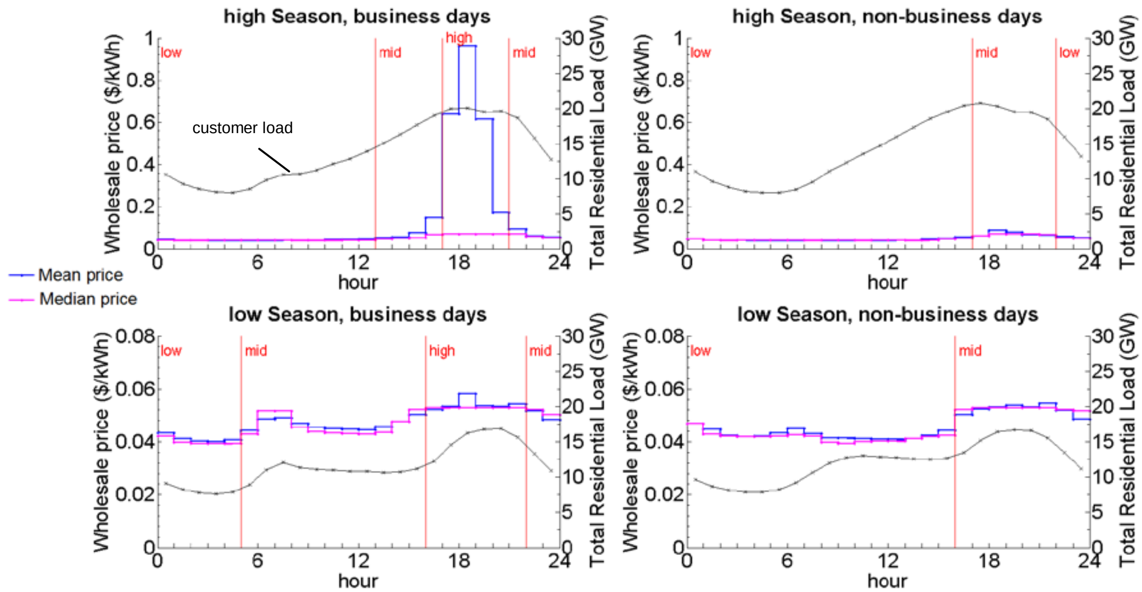

Figure 12: Average wholesale electricity prices, aggregate residential load by TOU season, and TOU period definitions (33% RE mix scenario)

Table 12 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.[36]

Table 12: 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 12). In contrast with the reference scenario, peak residential consumption is well correlated with peak prices in the 33% RE mix scenario; the correlation coefficient between average residential demand (net of behind-the-meter PV) and average

[36] 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.

wholesale prices in high-season business days is 0.68, whereas it is 0.44 for the reference scenario.[37] 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 13).

Table 13: 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 14: 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 $0.192/kWh with net metering,[38] 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,[39] 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

[37] 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.

[38] The average rate is $0.191/kWh with hourly netting, or 7% higher than with the reference scenario.

[39] The residual revenue adder is $0.093/kWh with hourly netting, or 9% higher than with the reference scenario.

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 15).[40]

Table 15: 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 16). 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).

Table 16: 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%

[40] Customers could mitigate the bill impact of these high-priced hours if we assume price elasticity, a scenario presented in Section 3.4.

3.3.2 Value of bill savings relative to reference scenario

In this section, we 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 13.

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. 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.

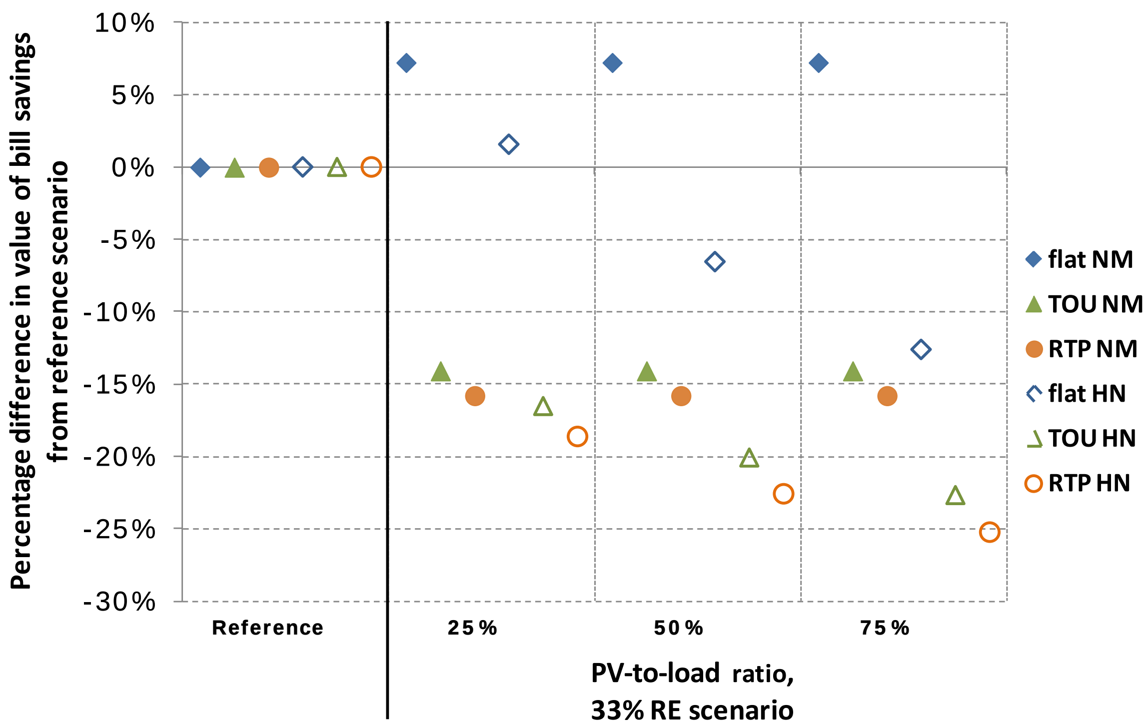

Figure 13. Comparing value of bill savings between reference and 33% RE mix scenarios

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 13). 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, we 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 our 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.

3.3.3 Value of bill savings relative to flat rate

Section 3.3.1 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 14 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 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 our 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 our 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.[41]

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 14, the median value of bill savings for customers with the flat rate and hourly netting is 43% lower than with the flat rate and

[41] 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.

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 our sample with a 25% PV-to-load ratio.

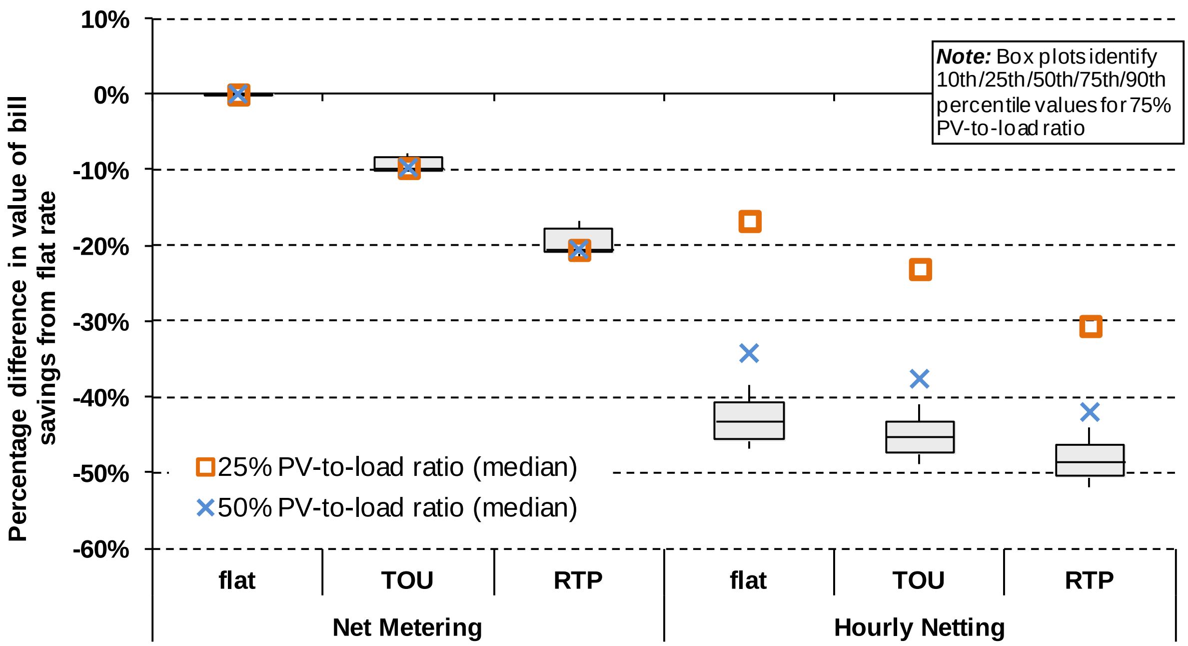

Figure 14: Relative value of bill savings from PV for flat, TOU, and RTP rates, for net metering and hourly netting, for the 33% RE mix scenario

3.4 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, we "force" 6.33 GW of pumped hydro storage into the system, in addition to the existing 3.56 GW of pumped hydro currently in California.[42] 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.

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 15). 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 our 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.[43] 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

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

[43] 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.

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 15), 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 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.[44]

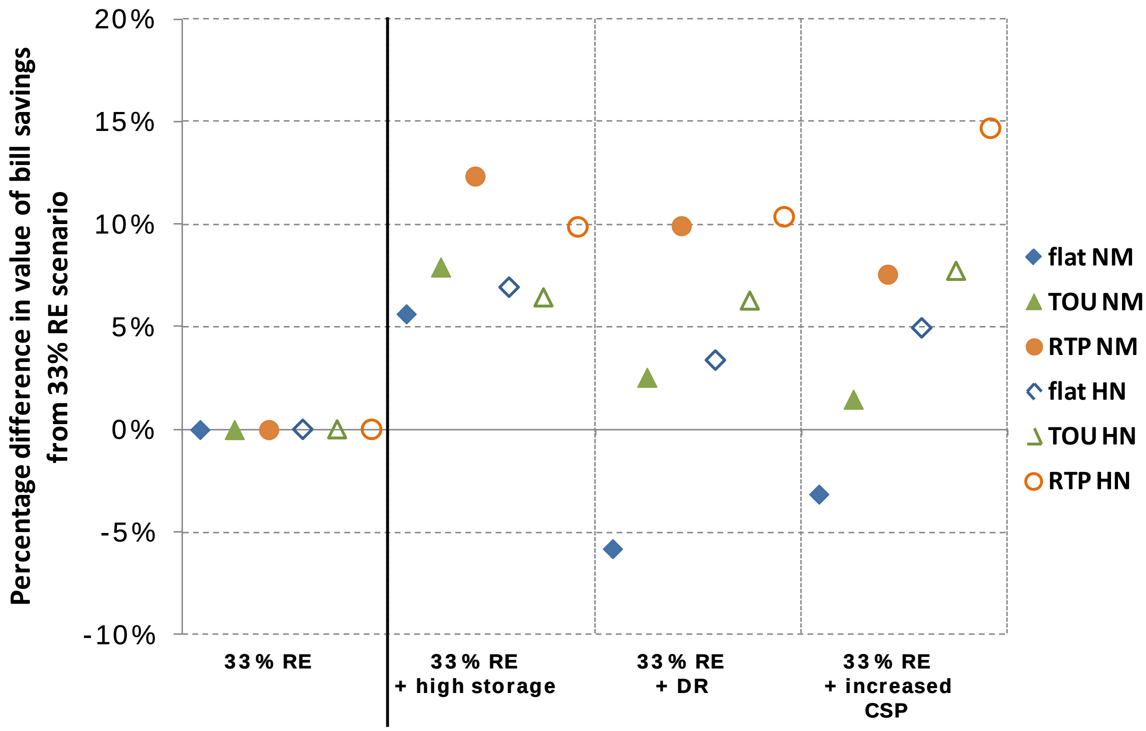

Figure 15: Change in value of bill savings from 33% RE to 33% RE integration scenarios, assuming a 75% PV-to-load ratio

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 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

[44] 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.

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 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 Appendix C).

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.

3.5 Results summary

This section presents the value of bill savings for all rate options, compensation schemes, and scenarios considered in this study, relative to the median value of bill savings for the flat rate with net metering (with no IBP or tiering) in the reference scenario. These are compiled in Figure 16, for customers with a 75% PV-to-load ratio.

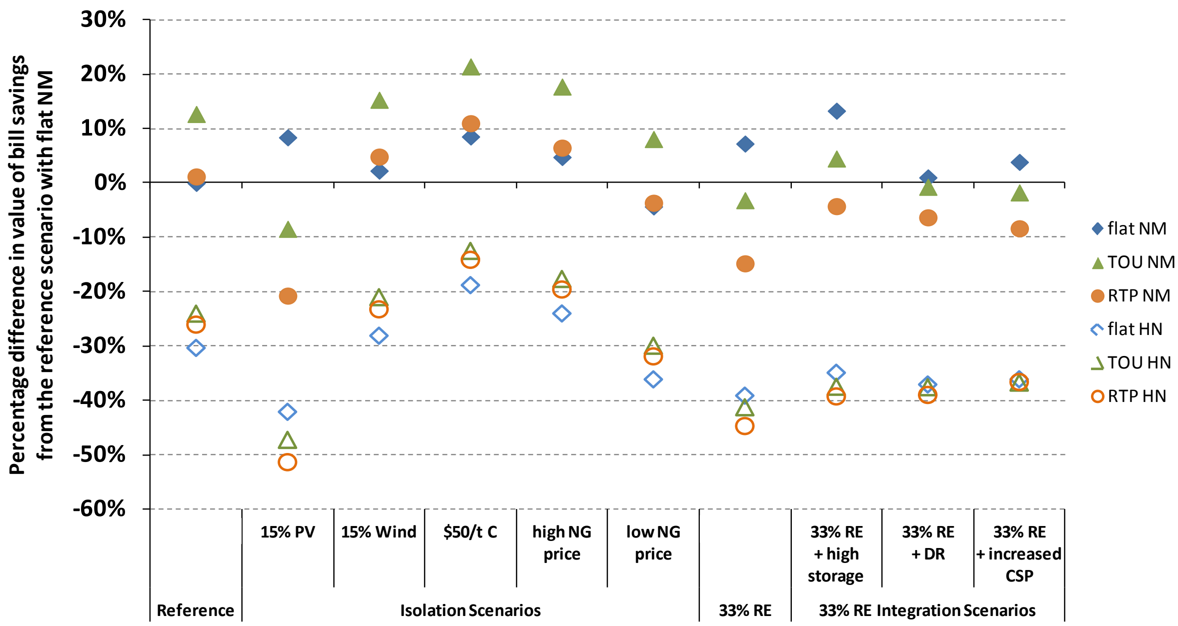

Figure 16: Median value of bill savings from PV for flat, TOU, and RTP rates, for net metering and hourly netting, for all scenarios, relative to the reference scenario with flat rate with net metering. 75% PV-to-load ratio assumed

We 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 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 as a loose case study, we seek to characterize 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 and return on investment for PV system owners.

One central issue addressed in this report is the effect of greater aggregate solar penetration on the value of bill savings from behind-the-meter PV; several key, inter-related findings emerge. In general, we find that 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 is 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 (i.e., 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. However, because PV generation from behind-the-meter PV is compensated at the retail rate, the drop in bill savings is muted 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. Regardless, with time varying rates or hourly netting or both, we still find 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 additional policy support or both.

Our 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 our 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. 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, 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 find themselves balancing 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 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.

Consistent with the findings in Darghouth et al. (2011), 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 this 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 our analysis are lower than under net metering, 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 report 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.

In addition to wholesale electricity market scenarios with high solar penetration, 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).

Although IBP was not among the rate structures included within the scenario analyses of this study, our 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, we find that 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 report 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 report.

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.** This study relies on a variety of assumptions that are based loosely on California's electricity market, and the results of the analysis could differ in significant ways if assumptions characteristic of other regions were used instead. Three California-specific aspects of our 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, and thus a lower volumetric adder, would impact our results 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. 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. (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.

- **Energy-Only Wholesale Electricity Market Design.** The wholesale market modeled in this study is an energy-only market where generators recover some portion of their fixed costs during hours in which scarcity pricing pushes prices higher than marginal costs. Many organized wholesale electricity markets in the United States, instead, currently consist 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 and are lower, on average, than under an energy-only market design; however, the capacity payments create an additional cost that must be recovered through retail rates. These differences can affect retail rates and the value of bill savings for behind-the-meter PV in several important ways, depending on how the capacity payments are recovered through retail rates. If the side capacity payments were to be recovered via a flat volumetric adder for retail residential customers, we would expect no change in the value of bill savings under flat retail rates, for any of the scenarios. Time-varying rates, however, would be 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. This would result in a lower value of bill savings for scenarios with lower grid PV penetrations, since PV generates in hours with scarcity prices that would be reduced due to the price cap. Conversely, in electricity market scenarios with higher PV penetrations, the value of bill savings would increase, as the price spikes in these scenarios do not occur when PV generates and thus the reduction in energy costs during those hours would not affect PV compensation, while the additional volumetric charge to recover capacity market costs would lead to an increase in retail rates during hours when PV generation occurs (again, assuming that capacity market costs are recovered from residential customers through a flat volumetric charge). In short, under an electricity market design featuring an energy market with price caps and a parallel capacity market, the erosion in the value of bill savings that occurs at high solar penetration levels under TOU and RTP rates would likely be reduced – with the extent of the reduction depending on the magnitude of the price cap and the way in which capacity costs are recovered through rates.

- **Focus on Residential Customers.** Although some aspects of our 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, our analysis included a limited number of wholesale market scenarios, and we therefore make no claim to have exhaustively considered the full range of possible uncertainties in future wholesale market conditions. 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 our 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.

- **Limited Set of Retail Rate Options Considered for Recovering Fixed Costs.** This 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. Alternatively, some utilities have proposed and applied standby charges for customer-sited distributed generation. If, within our analysis, fixed costs were recovered through a fixed customer charge rather than through a volumetric adder, or if standby charges were applied, the most obvious result would be a drop in the value of bill savings from PV. The magnitude of that decline would depend on the design of the customer or standby charge.

- **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. 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.

- **PV Azimuth and Tilt.** In this study, we assume that all residential and other distributed PV systems are oriented due south (i.e., an azimuth of 180°) and tilted 25°. This assumption is employed both in the wholesale electricity market simulation to develop hourly wholesale electricity prices, and also when calculating annual electricity bills for the 226 individual residential customers in our analysis. In reality, however, distributed PV arrays may be oriented with any number of directions and tilts, depending in part on the structural features of the rooftop and site. If a greater variety of azimuths and tilts were assumed within the wholesale electricity market simulation, this would lead to a flatter daily PV generation profile, which would somewhat mute the impact of high solar penetration on the temporal profile of wholesale electricity prices. This, in turn, would lead to an increase in the value of bill savings from behind-the-meter residential PV under high solar penetration scenarios (i.e., it would reduce the reduction in bill savings that otherwise occurs with increased solar penetration). In addition, when calculating annual utility bills for customers with PV, one could examine alternate orientations. As others have documented, including Darghouth et al (2011), PV systems oriented south-westerly may generate higher bill savings per kWh of PV generation when compensated under time-varying rates (in regions with afternoon peak demands).

Despite these limitations, this study'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 study'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 in this scoping study 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.

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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)

		Net Metering				Hourly Netting			
	Description	T&D and misc.	Utility-owned generation	renewable adder	Total	T&D and misc.	Utility-owned generation	renewable adder	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
	high wind	$0.101	$0.004	$0.020	$0.125	$0.101	$0.004	$0.020	$0.125
	high C price	$0.101	$0.004	$0.010	$0.115	$0.101	$0.004	$0.010	$0.115
	high NG price	$0.101	$0.004	$0.010	$0.115	$0.101	$0.004	$0.010	$0.115
	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
	Demand Response	$0.105	$0.004	$0.031	$0.140	$0.104	$0.004	$0.031	$0.139
	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}).

Table A-2. R_{adder}, R_{gen}, and R_{total} for flat rate, under net metering and hourly netting ($/kWh)

	description	Net Metering R_{gen}	Net Metering R_{adder}	Net Metering R_{total}	Hourly Netting R_{gen}	Hourly Netting R_{adder}	Hourly Netting 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.

Table A-3. Time-of-use period definitions for peak season

	description	Business Day Low	Business Day Mid	Business Day High	Non-business day Low	Non-business day 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
Isolation scenarios	high wind	0 - 8 and 23 - 0	8 - 14 and 18 - 23	14 - 18	0 - 14 and 21 - 0	14 - 21
Isolation scenarios	high C price	0 - 9 and 23 - 0	9 - 13 and 19 - 23	13 - 19	0 - 12 and 23 - 0	12 - 23
Isolation scenarios	high NG price	0 - 9 and 23 - 0	9 - 13 and 19 - 23	13 - 19	0 - 13 and 22 - 0	13 - 22
Isolation scenarios	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
RE Mix integration scenarios	Demand Response	1 - 10	10 - 17 and 22 - 1	17 - 22	0 - 17 and 23 - 0	17 - 23
RE Mix integration scenarios	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 Table A-4, 0=midnight, 12=noon.

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
	high wind	0 - 6 and 23 - 0	6 - 23	-	0 - 9 and 23 - 0	9 - 23
	high C price	0 - 6 and 23 - 0	6 - 23	-	0 - 9 and 23 - 0	9 - 23
	high NG price	0 - 6 and 23 - 0	6 - 23	-	1 - 9 and 23 - 1	9 - 23
	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
	Demand Response	1 - 5	5 - 16 and 22 - 1	16 - 22	0 - 16	16 - 0
	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)

	description	Net Metering Low	Net Metering Mid	Net Metering High	Hourly Netting Low	Hourly Netting Mid	Hourly Netting 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)

	description	Net Metering Low	Net Metering Mid	Net Metering High	Hourly Netting Low	Hourly Netting Mid	Hourly Netting 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.

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 2.3.6.

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%
Isolation scenarios	high wind	11.3%	18.0%	18.7%	12.6%	39.4%	-
Isolation scenarios	high C price	9.9%	15.9%	21.5%	12.6%	40.1%	-
Isolation scenarios	high NG price	10.7%	14.5%	22.5%	12.6%	39.7%	-
Isolation scenarios	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%
RE Mix integration scenarios	Demand Response	13.7%	16.1%	10.7%	15.2%	29.9%	14.3%
RE Mix integration scenarios	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 2.3.6.

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%
Isolation scenarios	high wind	7.8%	22.2%	10.4%	1.2%	58.4%	-
Isolation scenarios	high C price	5.6%	20.0%	14.7%	1.2%	58.4%	-
Isolation scenarios	high NG price	7.3%	18.4%	14.7%	1.2%	58.4%	-
Isolation scenarios	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%
RE Mix integration scenarios	Demand Response	14.3%	22.8%	1.5%	17.3%	39.9%	4.2%
RE Mix integration scenarios	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%
	high wind	5.7%	19.8%	30.4%	0.8%	43.3%	-
	high C price	4.1%	17.1%	33.5%	0.8%	44.4%	-
	high NG price	5.2%	15.3%	34.9%	0.8%	43.7%	-
	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%
	Demand Response	13.9%	25.6%	2.1%	15.9%	38.3%	4.2%
	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 2.3.6.

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 2.3.6.

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 ($\$/\boldsymbol{kWh\ of\ PV\ generation}$).

	description	net metering	hourly netting: 25% PV-to-load	hourly netting: 50% PV-to-load	hourly netting: 75% PV-to-load
	Reference	0.179	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 ($\$/\boldsymbol{kWh\ of\ PV\ generation}$).

	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	hourly netting 50% PV-to-load	hourly netting 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
Isolation scenarios	high wind	0.187	0.169	0.149	0.137
Isolation scenarios	high C price	0.198	0.182	0.164	0.153
Isolation scenarios	high NG price	0.190	0.174	0.155	0.144
Isolation scenarios	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
RE Mix integration scenarios	Demand Response	0.167	0.146	0.122	0.109
RE Mix integration scenarios	Increased CSP / decreased PV	0.164	0.146	0.125	0.113