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Michael Alter
Jason Peuquet

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Michael Alter and Jason Peuquet
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Client:
Ella Zhou
Strategic Energy Analysis Center
National Renewable Energy Laboratory

Harvard Kennedy School:
Faculty Advisor: Henry Lee
PAE Seminar Leader: Phil Hanser

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LIST OF ACRONYMS

CAISO – California Independent System Operator

CPUC – California Public Utilities Commission

DG – Distributed generation

EPRI – Electric Power Research Institute

FERC – Federal Energy Regulatory Commission

IOU – Investor Owned Utility

IREC – Interstate Renewable Energy Council

kW – kilowatt

kWh – kilowatt hour

MIT – Massachusetts Institute of Technology

NEM – Net Energy Metering

NJ BPU – New Jersey Board of Public Utilities

NREL – National Renewable Energy Laboratory

PV – Photovoltaic

SAM – System Advisor Model (developed by NREL)

SEIA – Solar Energy Industries Association

TOU – Time-of-use

U.S. DOE – U.S. Department of Energy

U.S. HHS – U.S. Department of Health and Human Services

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EXECUTIVE SUMMARY

The long-held practice of utilities generating revenues from customers only through fixed and volumetric charges is in the midst of being redefined. Utilities are seeking alternatives to standard electricity rates with net energy metering (NEM) that will more effectively recover the costs of serving particular customers. However, it is very difficult to determine the costs of serving individual residential customers. The expansion of distributed generation at the residential level, including solar photovoltaic (PV) systems, has further complicated the process of determining the cost of service for this class of customers. Recent regulatory developments in various states demonstrate the emphasis utilities and regulators have put on transitioning to alternative residential rate structures, including higher fixed charges, minimum monthly bills, time-of-use (TOU) rates, demand charges, and a combination of both.

One of the considerations that goes into rate design is how it impacts customer equity, or fairness. Utilities and regulators across the country define equity in different ways, with some placing more emphasis on the scale of bill impacts on a dollar and percentage change basis, while others place emphasis on a concept of gradualism that seeks to prevent large bill increases for certain customer segments in a short timeframe or overall progressivity. Almost any decision on rate structure design will impact equity among customers, but it is unclear how different rate structures will impact equity considerations across the entire utility customer base, both those with and without residential PV systems. This study seeks to add much-needed clarity into this policy discussion around equity by analyzing the following question:

> **What are the income distributional impacts of transitioning from standard rates (with NEM) to alternative rate structures for residential customers with and without PV systems?**

This analysis relies on the National Renewable Energy Laboratory's (NREL) System Advisor Model (SAM) to model annual utility bills for residential customers with and without PV systems in five geographical areas: California (PG&E), Arizona (APS), Nevada (NV Energy), Colorado (PSCo), and Massachusetts (Eversource). The rate structures examined included a standard rate (which enabled NEM) as a baseline along with a $30 fixed monthly charge, $30 minimum monthly bills, a multi-period TOU rate, a $10/kilowatt (kW) demand charge, and a combination TOU rate and demand charge. Additionally, battery storage is included for additional simulations under the TOU rate, the demand charge, and the combined TOU rate and demand charge. Battery storage functionality in the SAM software does not impact customers who do not have PV systems and customers under standard rates, fixed charges, and minimum monthly bills all with NEM (see *Methodology* section). All rate structures were modeled with three varying load profiles for each specific geographic area: high, base, and low-usage levels. This study uses electric load as a proxy for income, albeit with notable caveats to that assumption (see *Methodology* section for more discussion). Even if the findings of this study are not extrapolated to make conclusions about income distributional impacts, the results offer useful insights on how alternative rate structures can have different impacts on annual electric bills for households with varying levels of electricity consumption.

Findings

The findings from the modeling results shed light on the income distributional impacts that switching from a standard rate with NEM to alternative rate structures can have on customer bills. The results are particularly meaningful given competing interpretations of fairness for electricity rates among electricity market stakeholders.

The results indicate four main takeaways for fairness definitions:

- First, if utilities and regulators were to define fairness as being an equal dollar change for all types of residential customers, then instituting fixed charges would best satisfy that goal.
- Second, however, if utilities and regulators were to define fairness as creating progressivity on annual bills (or changes to annual bills) within the class of residential customers, then TOU rates and the combination of TOU rates and demand charges would be a viable mechanism for customers without PV systems. For customers with PV systems, all of the alternative rate structures created bill impacts that were regressive.
- Third, if utilities and regulators were to incorporate the gradualism principle of avoiding significant changes in customer bills within a short time period into their definition of fairness, then higher fixed charges would again be a poor mechanism for achieving gradualism given how this rate structure produced the largest dollar and percentage increases on customer bills within a given year out of all rate structures analyzed.
- Fourth, if utilities and regulators were to define fairness as roughly equal percent changes in customer bills in a given year, then minimum monthly bills and demand charges (for non-PV customers) would best achieve that definitional goal.

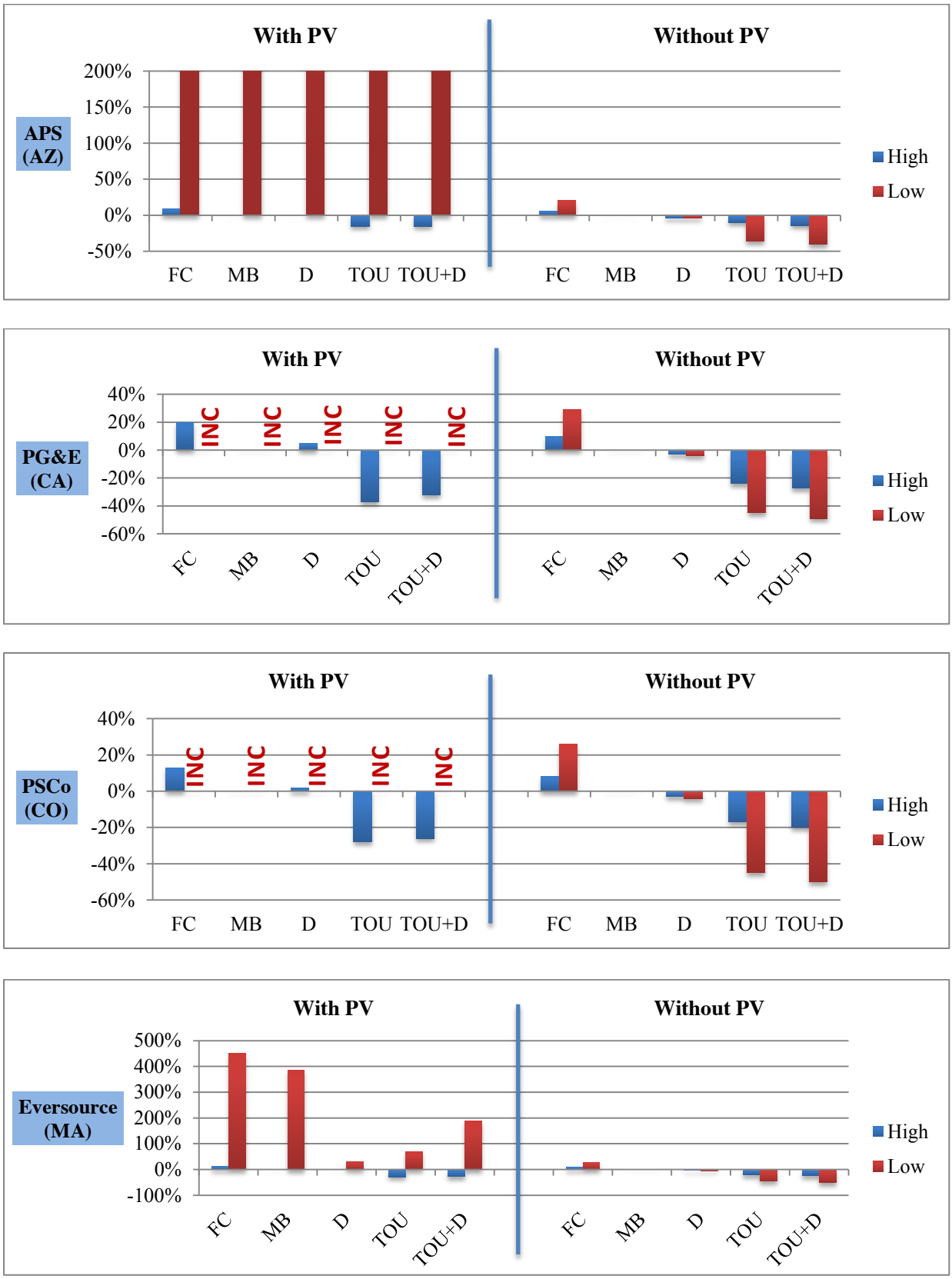
The model results presented several other overall findings for the impacts particular rate structures had on residential customer bills when transitioning away from a standard tiered rate base with NEM:

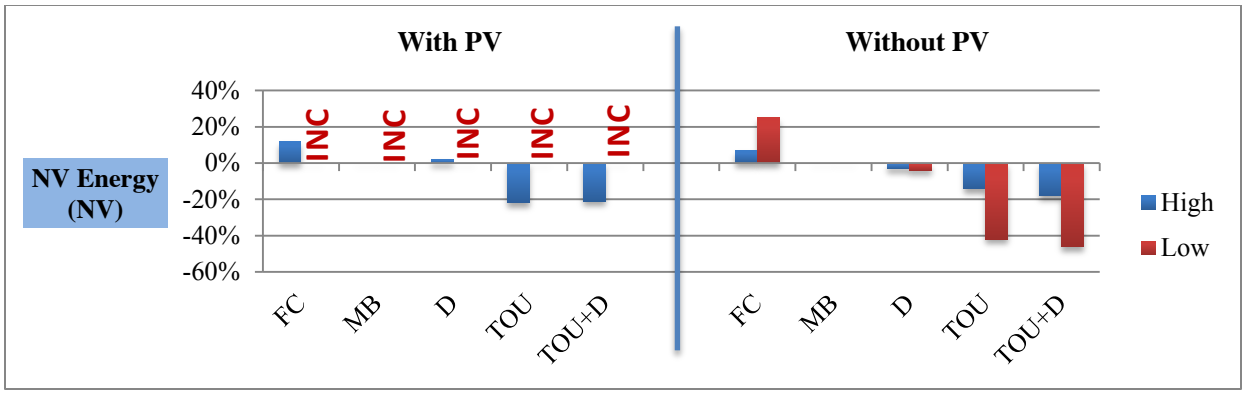
All residential customers and rate structures:

- The $30 fixed monthly charge resulted in the largest increases in annual bills from the standard rate, both in dollar terms and as a percentage, for all customers across all five utilities analyzed.
- Minimum monthly bills also created very large and regressive impacts on annual bills for low load/income PV customers.
- While trends in bill impacts were evident across utilities for alternative rate structures, such as the direction of bill changes as a result of a given rate structure, there was notable variation in the magnitude of results between each utility.
- For customers with PV systems, all alternative rate structures produced annual bill impacts that were regressive compared to base electric bills under the standard rate.
- The larger the load profile, the more variation there was for annual bills between the utilities.
- For customers without PV systems, only higher fixed charges produced annual bill impacts that were regressive compared to standard rates, with all others creating annual bill changes that were either distributionally neutral or progressive.

Figure 1 displays the percentage changes in monthly bills by utility for each rate structure.

Figure 1: Percent Changes in Monthly Bills under Alternative Rate Structures





Note: INC denotes customers who incurred negative annual bills under the standard rate with NEM, but a positive bill under this rate structure. There is no established mathematical approach for calculating a percentage change from a negative value to a positive value, so the INC notation is used to show that there was in fact an increase in the annual bill. FC refers to fixed charges, MB refers to minimum monthly bills, D refers to demand charges, TOU refers to time-of-use rate, TOU+D refers to time-of-use rate with demand charge.

The results of this analysis indicate that utilities and regulators considering adopting alternative rate structures, either individually or in combination with one another due to any number of concerns about the economic efficiency or equity impacts of net metering policies, may end up adding new financial burdens onto low-income/load households. Thus, standard rates with net metering appeared to have the least regressive impacts on electric bills for residential customers with PV systems compared to the alternative rate structures examined.

Recommendations

The above findings, both across all analyzed rate structure alternatives and within each rate structure, provide support for a few recommendations to utilities, policymakers, and other rate design stakeholders. Two additional recommendations focus on NREL's SAM platform.

Recommendations for Rate Structure Decision-Making

1. Consider geographic location and area-specific characteristics as a central factor in assessing the distributional impacts of rate structure decisions.

Changes in customer bills (both in dollars and percentage terms) can differ significantly across geographic locations for the same load/income category and rate structure. As a result of the geographic variability in PV system output and load patterns, not to mention existing rate structures and characteristics of local grids, policymakers and energy market stakeholders must assess the specific impacts of any rate structures on their region.

2. Avoid rapid changes to alternative rate structures

Some rate structures had much larger bill-increasing impacts on customer bills than others. For instance, bill increases under minimum bills and fixed charges reached up to $300+, compared to demand charges of $15-$30 for low load/income customers with PV systems. The scale of the difference between these results shows how some rate structures have the potential to sharply increase annual bills for residential PV customers in a very short timeframe, both in terms of dollar changes and percent changes. It is critical that policymakers assess the current magnitudes of electric bills for customers to which any change would apply and then adjust the time interval in which customers can fully transition to new rate structures.

3. Choose a definition of fairness that best balances overall goals, and consider how that definition creates preferences for or against certain rate structures

Equity is a central criterion for many utilities and regulators when designing rates, but the specific definition used for equity can make a big difference in which rate structure these stakeholders view as being ideal. If equity were defined in terms of creating progressive results, then utilities and regulators would need to be aware that all of the modeled rate structures created regressive results for residential PV customers, while only fixed charges created regressive bill changes for residential customers without PV. On the other hand, if equity were defined as creating equal impacts, either in dollar or percentage terms, then other rate structures could better suit the goal. Thus, it is impossible to make a blanket claim about which rate structure is best at addressing equity considerations.

Recommendations for System Advisor Model Enhancements

1. Create SAM Functionality That Allows for Specification of Behavioral Responses

When SAM calculates customer bills under alternative rate structures and with and without PV systems, it holds electric load constant. In reality, however, the introduction of a new rate structure or the decision to install PV systems may create incentives to change behavior and/or reflect an underlying difference in observable or unobservable characteristics. In order to allow for the generation of results for different kinds of customers with respect to behavioral responses, it would be useful if SAM were to allow users to specify behavioral responses from customers under different rate structures and with and without PV. Ultimately, this functionality would assist utilities and regulators in understanding how revenues may be impacted under various rate structures due to behavioral responses.

2. Allow Batteries to Reference Rate Structures and Minimize Electric Bills within SAM

As utilities continue to transition towards alternative rate structures for residential customers with and without PV systems that incentivize time-shifting and load leveling of electricity consumption (i.e. demand charges and TOU rates, or a combination of the two), residential battery storage will likely play a larger role in determining a customer's bill. Yet, SAM currently only allows battery storage to be deployed with the objective of minimizing consumption from the grid, but it would be beneficial to enable SAM to simulate battery storage with the intent of minimizing bills while incorporating the modeled rate structure. If rate structures like demand charges and TOU rates were to apply to all residential customers, it would become increasingly important to understand how battery deployment would affect bills for residential customers with and without PV systems.

INTRODUCTION

The National Renewable Energy Laboratory (NREL) is a federal laboratory based in Golden, Colorado that is funded largely through the U.S. Department of Energy. As part of its mission, NREL "develops clean energy and energy efficiency technologies and practices, advances related science and engineering, and provides knowledge and innovations to integrate energy systems at all scales" (NREL, 2016). NREL is at the forefront of providing innovative research and technologies that will shape the future trajectory of renewable energy in the United States and beyond.

A major focus area for NREL and other key stakeholders is the integration of distributed generation (DG) into the electricity grid, including residential solar photovoltaic (PV) systems. The growing interest in DG poses many opportunities and challenges for today's electricity system, electric customers, and policymakers – not to mention future generations. DG often refers to a broader group of technologies for on-site power generation and/or power management – such as PV and wind systems or diesel generators – that consumers or power generators can aggregate to meet some or all of electricity demand. This analysis uses the term 'residential PV' to refer to smaller-scale and customer-sited PV generation that "feeds into the distribution grid, rather than through the bulk transmission system…." (FERC, 2007). At low levels of market penetration, DG technologies have negligible impacts on transmission systems but have larger effects on the amount of direction of electrical flows on distribution systems.

New residential PV installations have increased steadily each year since the mid-2000s, rising from roughly 200 MW/year in 2010 to roughly 2,000 MW/year in 2015. Near the end of 2014, the U.S. had a total of nearly 8,000 MW of residential PV systems installed – up from about 450 MW of capacity in 2009 (SEIA and GTM Research, 2015; IREC, 2010). Key stakeholders are actively investigating how this continued growth of DG might affect decisions on utility rate design in the future.

Many utilities have already transitioned or are currently considering a transition away from historical standard rates, with net energy metering (NEM) for residential PV customers, to more efficiently and/or equitably recover the true costs of servicing customers (see *Background* for more discussion on how cost of service is determined). However, the expanding penetration of residential customers with PV has complicated the process of identifying rate structures that effectively balance the criteria proposed by power sector experts, including capital attraction, economic efficiency, consumer rationing, fairness to ratepayers, and revenue predictability for utilities and bill predictability for consumers, among other principles (Bonbright, 1961).

There are many criteria by which to evaluate a rate structure, but this study builds on previous NREL research on rate structure impacts on customer bills (Bird et al., 2015). Specifically, this study aims to answer the following question: *What are the income distributional impacts of transitioning from standard rates (with NEM) to alternative rate structures for residential customers with and without PV systems?* This question is important to multiple stakeholder groups that support maintaining or strengthening access to affordable electricity for low-income customers. Although the protection of low-income customers is only one component of the 'fairness to ratepayers' principle, it is one that continues to be a priority for many stakeholders.

This study investigates five alternative rate structures that utilities have mainly transitioned towards or evaluated in an attempt to more efficiently recover their full cost of service, and encourage dynamic efficiency both on an aggregate and individual customer level. These five structures are: an increased fixed charge, minimum monthly bills, a demand charge, a time-of-use (TOU) rate, and a combined TOU rate with a demand charge.

Fixed charges help recover non-volumetric costs associated with utilities' administrative and billing costs and other non-variable costs associated with connecting customers to the grid and maintaining those connections. Minimum monthly bills are intended to ensure that all customers are paying some minimum amount each month even if their net electricity consumption would otherwise lead to a lower bill. Demand charges, which are based on maximum kilowatt (kW) usage over a specified timeframe within a billing cycle (typically between 15 minutes and an hour), have the goal of assigning costs to some degree on the strain or 'demand' certain customers impose on the grid. These charges help utilities recover some of the costs associated with ensuring that the utility has enough capacity to meet the customer's peak demand. TOU rates – which might charge different amounts based on time of day, type of day (weekday vs. weekend), and season – are intended to charge customers higher amounts for electricity during the times in which it is more expensive for the utility to provide electricity because of high demand, constrained power supply, and/or constrained transmission and distribution lines. As recently implemented by Arizona Public Service (APS), a combined TOU rate and demand charge seeks to accomplish some of the objectives of each individual rate (APS, 2016).

Results for the TOU rate, demand charge, and combination TOU rate and demand charge were also modeled while incorporating the use of battery storage because of the price signals created for time-shifting of electricity consumption under these rate structure alternatives. Bill impacts under these rate structures were compared for residential PV customers with and without battery storage to see how the use of batteries changed their annual bills (see *Methodology* for more discussion on why batteries were excluded for other rate structure and for residential customers without PV).

Using household electric load as a rough proxy for income, this study analyzed how the five alternative rate structures impacted annual electric bills for customers of different load/income levels. Specifically, this study assumed that the three electric load profiles investigated correspond to three different levels of household income: high load corresponds to high income, base load corresponds to middle income, and low load corresponds to low income (see *Methodology* for more discussion on the pros and cons of this approach). Even if the findings of this study are not extrapolated to make conclusions about income distributional impacts, the results offer useful insights on how alternative rate structures can have different impacts on annual electric bills for households with varying levels of electricity consumption. In addition to the distinction made for household income, there was also a distinction made for residential customers with and without PV. Altogether, six different classes of customers are analyzed across each rate structure within a given geographical area: high-, middle-, and low-income residential customers with a PV system and high-, middle-, and low-income residential customers without a PV system. Differences in annual bills for each customer category are analyzed across each rate structure to determine the relative income distributional implications of each alternative rate structure.

Just as it is important to clarify what this study focuses on, it is equally important to clarify which questions it does not answer. This analysis includes a brief assessment of the broader impacts to the grid of increased distributed generation penetration, but it does not provide recommendations on how to address these various impacts. This is a critical question to investigate and understand as the penetration of electricity generation from distributed resources continues to increase, but it is beyond the purview of this analysis.

Although this study provides insight into the equity principles that policymakers should consider when designing electricity rates structures, it does not recommend any single definition of how equity should be measured. Brown and Faruqui discuss four of the leading interpretations of what fairness means within the context of utility rate design, suggesting that utilities and regulatory authorities can reasonably arrive at different conclusions about how to define and measure equity – including ensuring no large bill changes for some customers but small changes for others within a short period, no significant changes in revenues from each customer class, setting the same average tariff [cents per kilowatt-hour (kWh)] for all customers, and a Rawlsian approach of providing the largest benefit to the most disadvantaged (Brown and Faruqui, 2014). Although there is no inherently best approach to defining fairness, this study provides key stakeholders with results that are important to consider irrespective of the fairness definition being used.

While this study refers to the impacts on annual bills as regressive, progressive, or neutral, it does not comment on the underlying progressivity or regressivity of the rate structures themselves as that would depend on comparing annual bills to a customer's income, rather than the comparison of annual bill changes to initial annual bills assessed in this study. In other words, bill impacts from a change in rate structure may be regressive, but the change may preserve the overall progressivity of the system.

Finally, this study does not recommend one rate structure that should apply to all utilities. Utilities across the country face different circumstances with respect to things like customer base, geography, electricity generation mix, and level of grid development. The way in which utilities and regulators decide to balance efficiency and equity, among other considerations, will ultimately lead to a determination of the most appropriate rate structure for each utility.

METHODOLOGY

This analysis relies on NREL's System Advisor Model (SAM), a technology performance and economic model that is designed to guide policy decisions and analysis for multiple forms of renewable energy projects (Gilman and Dobos 2012). SAM incorporates Typical Meteorological Year 3 (TMY3) data of the National Solar Radiation Database to allow for variable weather and solar data based on the particular location modeled.

Five utility areas were selected in five different states for this study: Arizona Public Service (APS – Arizona), Eversource (Massachusetts), NV Energy (Nevada), Pacific Gas & Electric (PG&E – California), and Public Service Company of Colorado (PSCo – Colorado). Two major factors led to the selection of these utilities. First, some of the utilities were selected because the results of this study could potentially guide the current discussions about reforming NEM

policies in these states. Second, utilities were selected to provide diversification for things like levels of PV system output, climate, customer load profiles, customer demographics, and current residential PV penetration levels. The focus on only one utility within a state recognizes the fluctuations in many key input variables that could occur even within a given state.

Simulations were run for at least three different geographies within each utility's service area and the results were aggregated to provide overall utility results. This analysis aggregated residential customer utility bill results, both with and without PV systems, from each sub-jurisdiction within a utility area based on simple averaging rather than on the number of residential PV customers in each jurisdiction or some other metric.

Load dataset profiles that represent hourly household consumption over a 'typical' year are obtained from Energy Plus Software. Energy Plus uses a nationally representative, base-case load profile and reference housing parameters, designed using the "Build America Home Simulation Protocols" (Hendron et al., 2010). With these simulated datasets, SAM is able to calculate the net consumption of a household with a PV system (e.g. how much electricity it draws from the grid) in addition to the impact that different rate structures have on customer bills. Due to the fact that the customer load data from Energy Plus do not distinguish between customers with and without PV systems, this analysis assumed that load profiles are identical for households with and without PV systems. In reality, however, a residential customer's decision to install a PV system may prompt other behavior changes regarding electricity use. Conversely, customers who seek out DERs may differ in observable and unobservable ways that impact electricity use.

Three load profiles (high, base, and low) were modeled for each geographical location studied, as reported in Table 1.

Table 1: Annual Modeled Residential Load: "Low," "Base," and "High" Loads

Location	"Low" Average Annual Residential Electricity Consumption (kWh)	"Base" Average Annual Residential Electricity Consumption (kWh)	"High" Average Annual Residential Electricity Consumption (kWh)
Arizona – APS	5,916	11,375	18,419
California – PG&E	4,040	7,924	11,190
Colorado – PSCo	4,354	9,046	14,170
Massachusetts – Eversource	4,282	8,807	13,247
Nevada – NV Energy	4,638	9,714	15,388

Source: OpenEI, 2016

In a perfect study, data on load and income would be available on an individual household basis to calculate the specific relationship between the two variables in a given geographic region. However, this granularity of data was not available for this study. As such, annual residential electricity load serves as a proxy for income, with low-income households having a "low" load

profile, middle-income households having a "base" load profile, and high-income households having a "high" load profile. Multiple studies have investigated the relationship between load and income, but there is a lack of consensus about the nature of this relationship. One set of studies finds that electric consumption increases monotonically with income (Cayla, Maizi, and Marchand, 2011; Kelly, 2011; Filippini, 2011), another set of studies finds an inverted U-shape correlation between electric consumption and income (Foster, Tre, and Wodon, 2000), and finally other studies find a weak correlation between electric consumption and income (Borenstein and Davis, 2012).

There are two main critiques that load may not be an ideal proxy for income. First, the increasing penetration of DG can skew the relationship between load and income as middle- and high-income customers, who make up the majority of owned or leased residential PV systems, can significantly reduce or minimize (or entirely erase) their monthly load with DG systems. Second, there are many high-income customers living in apartments in urban areas whose frequent travel and smaller square footage (relative to a suburban home) can lead to low loads. Despite these potential shortcomings, previous studies (see Brown and Faruqui) have relied on the correlation between load and income in the absence of comprehensive data, and as discussed above there are a number of studies suggesting that load increases with income. Therefore, this analysis uses load as a proxy for income but fully acknowledges the caveats to this approach.

SAM allows users to define inputs about technology type and performance or rely on default modeling assumptions. This analysis held constant the PV system size at 5 kW based on NREL's OpenPV database, which shows that roughly half of PV installations are between 3-6 kW (Bird et al., 2015). Although the size of the PV system could have been adjusted to reflect average residential PV system sizes in each utility area, holding the system size constant across the different utilities allows for isolation of the effects due to changes in rate structure. The tilt of the modeled PV systems was set equal to the latitude of the geographic area for which the model was run, in line with best practices by PV installers. A full description of all input parameters used in this study is provided in Appendix I.

When modeling changes in customer bills for different rate structures, previous NREL studies have used the existing standard rate currently implemented in each utility area. Although this can provide more specific results for an individual utility based on its current rate structure, it makes comparing results across utilities difficult because of differing rate structures. Since one of the main aims of this analysis is to illustrate how the "best" rate structure is not the same for each utility, it is necessary to allow for a comparison of results across utilities. To do so, the analysis models the same rate structures across all five utilities examined.

PG&E's E-1 Residential Service Baseline Region X rate structure was used as the benchmark for all other rate designs and across all of the utilities. The E-1 rates are a tiered system of four energy charges that apply based on usage levels, with the energy charges rising from less than 15 cents per kWh in the first tier to nearly 32 cents in the top tier. In addition to analyzing results for this standard rate structure (which enabled NEM with a single meter with monthly rollover credits in kWh for residential PV customers), simulations were conducted for a $30 fixed charge, a $30 minimum monthly bill, a demand charge of $10/kW, PG&E's E-6 Residential Time of Use Baseline Region X, and a combination of the E-6 rate structure with the $10/kW demand charge.

When restructuring rate designs to create an additional charge, utilities might allow for a corresponding change to the energy charge to ensure revenue neutrality. Although the introduction of a fixed charge or monthly minimum bill would presumably lead to a reduction in energy charges, no changes were made to the energy charges because of an inability to calculate the levels that would appropriately lead to revenue neutrality. However, energy charges were reduced by $0.04/kWh with the addition of a demand charge (both for the standalone demand charge and the combination of the TOU rate and demand charge) due to NREL's finding that the average decrease in energy rates associated with the implementation of a demand charge ranged from $0.04-$0.05/kWh. Additionally, a recent NREL study shows that a $10/kW demand charge falls in the middle of currently deployed demand charges (Bird et al., 2015). Although this combination of demand charge and reduction in energy charges may not lead to perfect net-neutrality, it is still insightful for understanding the potential impacts of this rate design.

After the initial simulations for each rate structure, the use of battery storage was incorporated for the demand charge, TOU rate, and TOU rate with a demand charge. Under standard rates, and even with the inclusion of a fixed charge or minimum monthly bill, there is no incentive for battery storage as a mechanism for reducing bills because the grid acts as a free battery. However, under a demand charge, TOU rate, or TOU rate with a demand charge, there are price signals that incentivize the use of battery storage to reduce electricity bills.

These simulations included a battery storage device with specifications that resemble the latest version of the Tesla Powerwall, which is marketed as a home battery device (Tesla, 2016). The battery dispatch model used was peak shaving with 1-day look ahead, which enables daily references to the next day's solar resource and load data with the intention of minimizing consumption from the grid.

The battery function in SAM is built with four options for dispatch, each with the objective of minimizing consumption from the grid. However, the battery does not reference the electricity rate structure to minimize price. Consequently, there are no changes in bills for residential customers without a PV system with the addition of a battery because they are not able to minimize consumption from the grid without any on-site electricity generation. Results for these customers without PV are not included in the findings when focusing on the addition of batteries. In reality, there would be an opportunity to lower bills under TOU rates, demand charges, and a combination of a TOU rate with a demand charge for non-PV residential customers who have batteries.

BACKGROUND

Electricity Rates: Efficiency, Equity, and Gradualism

While current debates regarding the efficiency or fairness of utility rate structures have received new attention in the context of rising interest in distributed generation, the tradeoffs inherent in designing tariff structures are not new. On one hand, utilities and regulators seek to encourage long-term efficiency, but the most economically efficient solutions may disproportionately impact lower-income customers. Other considerations also include the desire for gradualism and predictability for electricity customers.

In the 1960s, Dr. James Bonbright – a Columbia professor and former chairman of the New York State Power Authority – helped establish ten overarching principles for electricity rate design:

- Effectiveness of meeting total revenue requirements
- Revenue stability and predictability
- Stability and predictability of tariffs themselves
- Discouragement of wasteful electricity use
- Internalization of all private and social costs, both present and in the future
- Fairness between customer, with equals treated equally
- Avoidance of undue discrimination
- Promotion of innovation and responses to changing supply and demand
- Simplicity, public acceptance, and feasibility of implementation
- Interpretation is well-defined and free from controversies

Those principles were eventually culled down to five in light of evolving power markets, though many of the principles still apply (Faruqui, Hledik, and Neenan, 2007). Importantly, no one criterion dominates others, and context is vital.

As noted above, however, these principles often come into conflict. A focus on economic efficiency in the past has led to a guiding principle called Ramsey pricing, which states that utilities or other electricity market firms should recover any gaps between long-term marginal cost pricing and the total cost of providing electricity services by charging customer groups based on the inverse of their demand price elasticities (Train, 1991). The result of this approach is to charge people with relatively inflexible electricity demand more for services in order to distort the market the least, which largely means charging lower-income customers more for electricity. However, regulatory commissions have historically limited the application of this pricing scheme by designing rates that implicitly create a cross-subsidy from commercial and industrial customers to residential customers, which is still possible even if industrial or wholesale electricity prices are lower than residential rates.

To correct some of the regressive nature of efficient electricity pricing and to better ensure access to electricity, many states provide subsidies or significant discounts on electricity and gas bills. California, for instance, has created the California Alternative Rates for Energy (CARE) program, which offers 30-35% discounts on electricity bills for qualifying households, based on the number of residents in a household and total gross income (CPUC, 2016a). The federal government also has offers the Low Income Home Energy Assistance Program, which assists low-income households with heating and cooling costs (U.S. HHS, 2016).

Following established guidelines for rate structures, utilities generally charge residential customers a combination of a fixed charge – sometimes called the customer charge, in dollars per month – and a volumetric variable energy charge ($ per kWh per month) to generate sufficient revenues in ways that meet the enumerated principles to the extent possible (Zummo, 2015). According to an analysis by the Electric Power Research Institute (EPRI), a typical residential customer consumes nearly 1,000 kWh of electricity each month and faces an average monthly electric bill of about $110. That $110 charge breaks down to $70 for generation, $30 for distribution, and $10 for transmission – collected through a $100 variable energy charge and a $10 fixed charge for transmission and distribution (EPRI, 2014). Utility bills also tend to include other 'social' charges to recoup the costs of low-income programs, energy efficiency initiatives,

nuclear plant decommissioning, or other renewable energy charges. For instance, New Jersey's Societal Benefits Charge collects revenues for these types of purposes, along with consumer education efforts (NJ BPU, 2016). The vast majority of distribution and transmission costs are fixed, however, and about 80% of the generation costs are variable in the sense that they depend on how much energy the residential customer actually uses (Zummo, 2015). Thus, the actual costs the utility faces for providing electricity reflect a much more even split between fixed and variable charges than the breakdown of fixed and volumetric charges of $10 and $100, respectively, that residential customers see on their bill. This is important in the context of residential PV because many utilities in the U.S. rely on NEM to compensate residential PV customers for solar generation – a method that can largely eliminate both the fixed and variable charges for these customers. Under NEM, PV customers can sell back any excess solar generation back to the utility at the full retail rate, enabling customers to potentially net out their entire monthly bill and pay nothing to the utility.

Following from many of these principles for rate structures, utilities and the public utility commissions that oversee them have many options in designing a rate structure for customers in certain geographic regions. NEM, the most common method today, allows meters for residential PV customers to run forward when the household is consuming more energy than it is producing, remain constant when solar production exactly equals energy use, and run backward when solar production exceeds household energy use. Importantly, rate structures can incorporate several design elements into one structure, such as adding a demand charge or TOU rate on top of standard rates with NEM. Box 1 below provides an overview of several more common rate structures, but does not present an exhaustive list of rate structure options for utilities and regulators. For instance, rising penetrations of distributed PV systems have prompted several jurisdictions, including Austin Energy (TX) and Lincoln Electric System (NE), to assess the locationally specific 'value of solar' from which utilities and regulators may base buy-back rates for PV customers and which may differ from retail rates (Zummo, 2015).

No one electricity rate structure can perfectly meet the goals of creating fair, stable, transparent, gradual, and dynamically efficient rate designs. For instance, protecting the equity criteria and charging lower-income customers less for electricity can increase electricity consumption beyond economically efficient levels. Similarly, exposing customers to real-time prices would achieve efficiency, but would subject customers to potentially large swings in monthly bills when they may have little ability to anticipate those costs and/or pay for them.

Additional Distributional Considerations That Residential PV Raises

Further confounding the difficulty of selecting locationally optimal rate designs is the rise of residential PV. Some rate structures may not fully recover the full cost of service from distributed PV customers, or the cost of service plus a reasonable economic return. Cost of service assessments compare the actual bills that customers pay to the actual fixed and volumetric costs the utility faces to serve specific customers. Some rate structures may over- or under-compensate residential PV customers for the true value of their reduced net energy demand and any exported surplus energy provided to the broader grid. However, the level of this over- and under-compensation to residential PV customers may be quite small.

Box 1: A Sample of Utility Rate Structure Options

Standard Rates

Description: A standard rate is an electricity tariff typically comprised of a fixed charge and an energy charge based on the kWh a customer consumes. Historically, the energy charge makes up the largest percentage of a customer's bill. Standard rate structures can use a flat rate that incorporates a single energy charge for all hours of the day and year and kWh of energy consumed or they can incorporate tiers based on how many kWh are consumed in a day or month.

Advantages: This rate structure is easy to convey to customers and can incentivize them to reduce electricity consumption.

Challenges: Standard rates may not be the most accurate way for a utility to recover the costs associated with servicing all customers. There are tradeoffs in determining whether rates should be the same for all customers, follow a declining-block schedule that has lower energy charges as electricity consumption increases, or follow an inclining-block schedule that has higher energy charges as electricity consumption increases.

Net Energy Metering (NEM)

Description: NEM enables customers with on-site solar generation to net out the amount of excess electricity sold back to the grid from how much electricity they consumed from the grid. There are multiple options for compensation under this structure: a single meter with monthly rollover credits in kWh (with a year-end sell rate on a $/kWh basis), a single meter with monthly rollover credits in $, a single meter with no monthly rollover credits, or two meters for tracking all consumption (purchased from the grid) and all solar sold into the grid.

Advantages: This rate structure is simple to implement on top of standard rates with existing meters.

Challenges: NEM can present revenue adequacy problems for utilities if they are unable to recover the fixed costs associated with keeping residential PV customers connected to the grid and the energy costs associated with supplying power at intermittent periods when solar panels are not producing sufficient power. Consequently, this may lead to equity challenges in some jurisdictions whereby utilities may charge customers without PV systems more, effectively creating a cross-subsidization from customers without PV systems to those with PV.

Fixed Charges

Description: A fixed charge is a single service-based charge each month which does not fluctuate with a customer's energy usage. These charges are primarily aimed at recovering utility administrative and billing costs, and can be adjusted up or down in response to revenue requirements.

Advantages: Fixed charges are easy to implement and convey to customers. They have oftentimes been used as a way to minimize utility revenue loss associated with distributed PV customers.

Challenges: Drawbacks to implementing fixed charges include the discouragement of energy efficiency, potential for reduced cost savings associated with distributed generation, and creating a larger burden for low-income customers compared to those with higher incomes.

Minimum Monthly Bills

Description: Minimum monthly bills set a floor on the amount customers must pay each month. Like fixed charges, they do not vary with the amount of electricity consumed. This rate structure would be triggered by customers who eliminate much of their monthly electricity consumption, especially those who leverage DG.

Advantages: This option ensures that all customers, including those with PV systems with minimal net loads, will pay at least the minimum bill each month.

Challenges: Depending on the level of any minimum monthly bill requirement, this option could discourage customers from minimizing net electricity consumption with DG. Additionally, this could negatively impact low-

income customers without DG who have low loads throughout the year or for certain months and thus have low electricity bills.

Demand Charges

Description: Demand charge structures take the peak kW used over a predefined time interval each month (usually 15 minutes, 30 minutes, or 1 hour) and multiply it by the demand charge ($ per kW). This charge is designed to reflect the cost the utility incurs by ensuring there is enough capacity to meet a customer's peak demand. At the end of the billing cycle, it is determined which time interval had the maximum electricity consumption. After averaging the demand over that time interval, the demand charge is multiplied by that figure to determine this portion of the bill. Rate structures including a demand charge will oftentimes have lower energy charges than under a standard rate. Historically, demand charges have largely been used for commercial and industrial customers, but some utilities are now applying this rate structure to residential customers (APS, 2012).

Advantages: One of the main advantages of implementing demand charges is that it may more accurately reflect the strain of high-peaking customers on grid costs. If effective, demand charges could induce customers to flatten their load profiles, potentially helping utilities save money by avoiding high-cost generators during spikes in demand. Additionally, this rate structure option could provide opportunities for bill savings with demand response, battery storage, and efficiency.

Challenges: Demand charges require the installation of smart/interval meters for customers subjected to this rate structure. This option could also adversely impact customers without the ability to manage coincident appliance usage or peak household usage.

Time-of-Use (TOU) Rates

Description: Time-of-use (TOU) rates create different energy charges based on a number of potential factors: time of day, weekday vs. weekend, and season. TOU rate schedules are designed to better reflect the actual cost of supplying electricity during the different time periods. While some TOU rate structures are complex and have 3-5 separate pricing tiers, many are more simplified and only distinguish between on- and off-peak time periods. Importantly, utilities and regulators can combine TOU rates with demand charges to both incentive load shifting and load leveling.

Advantages: Like demand charges, TOU rates may more accurately reflect strain on the grid, but in this case it is based on the time of consumption rather than peak consumption. This rate option could encourage energy conservation during peak times, which can lead to costs savings for both the utility and customers.

Challenges: It is difficult to set an appropriate TOU rate structure that fully incentivizes customers to shift electricity consumption away from on-peak time periods. This rate option could also adversely impact customers who lack the ability to alter the time dimension of their electricity consumption.

Sources: Zummo, 2015; Bird et al., 2015

In designing rate structures for electricity customer classes, with and without PV systems – including residential, commercial, and industrial customers, within relevant subgroupings – there are many types of cross subsidization that can occur. In these situations, certain customers may not fully bear all of the costs for the power, reliability, and distribution services they receive and/or provide to the grid via DG capabilities. Uniform fixed cost charges can create a cross subsidy from low energy to high energy consuming customers. Special customer classes for low-income customers can create a cross subsidy from all non-low-income customers to qualifying low-income customers. Fixed charges can create a cross subsidy from urban to rural customers, or vice versa. Demand charges, often in place only for commercial and industrial customers, can create a cross subsidy between residential and business customers if the charges do not fully

allocate costs for large swings in demand from businesses to those customer classes. There are likely to be varying income distributional impacts from all of these types of cross subsidization.

The growing prevalence of NEM customers in many U.S. states has prompted several studies from utilities, solar associations, consumer advocates, and regulatory agencies to assess to what extent cost shifts, if any and in what direction, have occurred between residential customers with and without rooftop PV systems. It is important to consider all the potential benefits and costs that residential PV customer generation can provide, as discussed later in this section, which can theoretically aggregate to positive or negative net impacts.

The research on cross subsidization involving residential customers with and without PV is in its infancy. But according to a study from the economic and environmental consulting firm E3, commissioned by the California Public Utilities Commission, the "costs associated with NEM generation are forecast to be approximately $1.1 billion per year in 2020," with roughly ⅔ of those costs stemming from residential NEM systems (CPUC, 2013). Though the report only looked at information from a single year (2011) for roughly 150,000 NEM customers across California's investor-owned utilities (IOUs), the report also found some evidence of a cost shift between residential DG customers and non-DG customers. In evaluating the full cost of service for DG customers, E3 compared actual NEM customer bills to the actual costs utilities face serving those customers, including fixed and volumetric costs. A cost of service analysis makes it possible to assess "whether customers who install NEM eligible systems pay more or less than the cost of providing them electricity service before and after they install a NEM eligible system."

As shown in Table 2 below, the study found that while, on average, all DG customers did continue to pay for the full costs of their systems after installing NEM eligible systems (moving from 133% full cost of service to 103%), there was a larger drop-off for residential customers with and without DG than for non-residential customers. Differences for residential customers were mainly explained by the size of the customer and tiered rates because as these customers were able to offset portions (or all) of their daily load, they would be subjected to the lower energy charges associated with lower tiers. Thus, residential DG customer utility bills were found to offset only 81% of the full costs of serving them, compared to 154% for their bills before the DG installation. Importantly, however, the relative changes to customer bills and full cost of service is not uniform across all utilities and customer classes. These results specifically reflect California, where ratepayers face very strongly tiered rate structures not found in many other places.

Table 2: Percent Cost of Service Recovery from NEM Customers in 2011, with and without PV Systems

	All CA IOUs (% of Full Cost of Service)	
Customer Type	Without System	With System
Residential	154%	81%
Non-Residential	122%	112%
Total	**133%**	**103%**

Source: California Public Utilities Commission and E3.

Importantly, E3's analysis did not quantify the values for a full range of potential benefits from DG systems, such as the benefits from diversifying the energy mix and helping to manage some periods of peak load on hot, sunny days. Thus, not recovering the full cost of service from residential DG customers may not necessarily be a net loss for society, but rather it indicates the potential for cross subsidization occurring. But only comprehensive 'value of solar' calculations can begin to address the question in full.

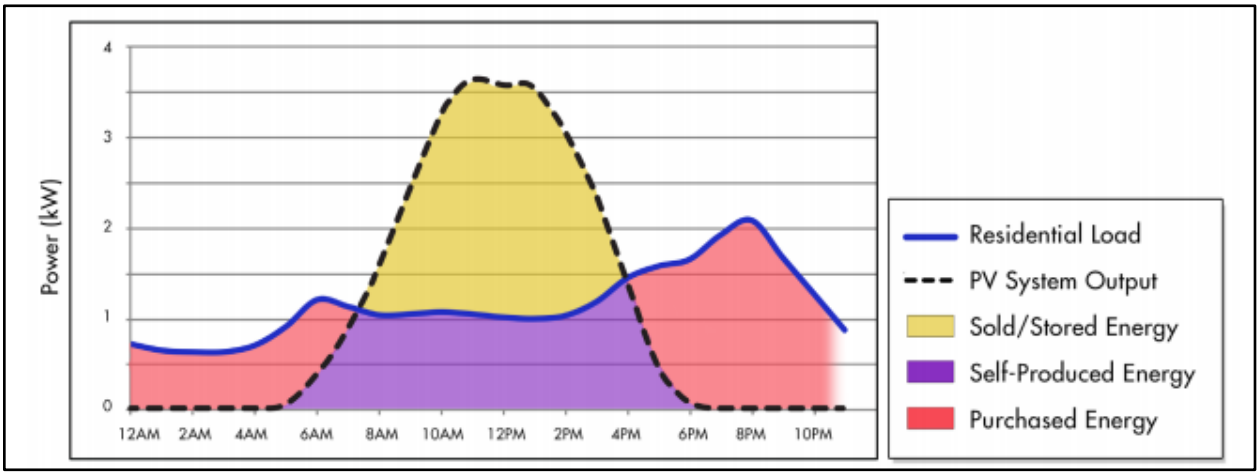
The Costs and Benefits of Distributed Generation

As mentioned at the beginning of the previous section, it is unclear whether cross-subsidization is occurring from non-DG to DG customers, or vice versa, without a full assessment of the costs and benefits of DG. That question is beyond the scope of this analysis given that the answer will be very context-dependent. However, a brief discussion of the theoretical benefits and costs of DG is necessary to see how distributional impacts factor in.

Integrating residential DG systems into the electric grid presents a number of potential benefits and costs, both for individuals and utilities as well as the broader public. DG resources allow customers to benefit from reducing their monthly and/or peak electricity consumption costs while offering utilities the ability to defer new generation investments or distribution line capacity investments in light of the electricity that distributed PV systems generate.

As a result of high solar output and/or low energy usage at a particular time, DG customers can export electricity back to the grid. Solar PV output is based on the strength of solar irradiance, which peaks in the middle of the day when other weather factors are not present, and any other weather factors, PV system tilt, or tree cover that could affect the strength of the solar resource for a given household. Residential load profiles, on the other hand, tend to reflect upticks in demand in the morning and early evening, with the latter reflecting peak demand. Importantly, neither of these daily peaking cycles are coincident with peak output from PV systems (see Figure 2) (EPRI, 2014).

Figure 2: Residential Load Profiles and Output from Distributed PV Systems Do Not Perfectly Align



Source: Electric Policy Research Institute, 2014.

Setting the utility electricity rates to integrate DG systems into the grid presents a number of technical challenges, cost-recovery challenges, and public policy challenges. The technical challenges of integrating DG include voltage controls, increasing demands on transformers, inverters to convert DC power from solar panels to the AC power of the electric grid, and challenges related to sending electricity both ways on a distribution and transmission system that was originally designed for largely unidirectional power transfers. While physical distribution and transmission systems can carry power in both directions, DG still can have "adverse impacts on system reliability, power control, and safety" (MIT, 2011). Because some of these technical challenges – particularly the added demands on the distribution system – add direct costs for the utilities, the question of adequately recouping costs becomes important for the utility. Importantly, many of the costs that DG imposes can be solved either through technology changes, technology requirements, or other public policies to ensure greater coordination. For example, requiring households to install certain add-ons to inverters or requiring utilities to add certain equipment at the substation level can easily manage DG's voltage challenges.

With rising shares of the electricity mix coming from intermittent renewable resources, integrating them into regional grids will sometimes require energy systems to invest in more peaking or backup facilities when renewable energy generators are producing little or no power. The extent of this pressure and its impacts on raising system-wide costs – a phenomenon known as the 'duck curve' – will depend on the spatial concentrations of DG and existing generating units as well as when new investments in generation or distribution capacity may have been needed (CAISO, 2013). Researchers at EPRI have found that "completely displacing a consumer's energy requirements with self-generation, as with zero-net-energy residence, often does not alleviate the need for capacity from the utility," and in some regions of the U.S. peak load is increasing at a faster rate than overall energy consumption (EPRI, 2015). These trends have coincided with rising electricity prices, creating further incentives for residences to invest in DER, potentially further increasing demands on peak usage.

However, studies claim that private residential decisions on whether to install DG can provide benefits to utilities and transmission and distribution companies. Purchasing residential DG

power can help defray costs for new generating assets and new distribution lines, while also potentially reducing line losses on transmission lines if DG-supplied power largely stays within distribution systems. Importantly, helping to defray system-wide costs can also provide significant benefits to the electric grid and, thus, to non-DG customers. Those benefits can include enhanced power reliability, power diversification, and environmental benefits from reduced emissions and land use. Given the relatively recent rise of DG technologies, more research is needed to assess some of the specific costs and benefits that DG imposes and provides, respectively. For instance, assessing the extent of additional reserve requirements as a result of DG is an ongoing realm of research, as is the assessing the costs and benefits of DG on power system operations at the timescale of a few seconds, among several other topics related to DG (Denholm, 2014).

Table 3: A Sample of Potential Costs and Benefits of Distributed Generation

	Benefits	**Costs**
Power Reliability and Security	● Increased power diversity ● Increased security for critical loads ● Reduced vulnerability to terrorism	● Reduced predictability of power flows from intermittent renewable energy technologies ● Increased concern for system reliability and power control
Economic Impact	● Deferred costs for generation, transmission, and distribution services ● Reduced line losses	● Lower utilization factors for intermittent renewable energy resources than conventional resources ● Ongoing need for capacity from grid given intermittent nature of renewable technologies ● Increased one-time interconnection services ● Potential for increased transmission and distribution capacity from two-way power flows
Environmental Impact	● Reduced line losses ● Reduced particulate emissions ● Reduced land use for generation and transmission	● Potential for increased particulate emissions if additional periods of low or negative power prices drive out baseload nuclear, replaced with coal or natural gas
Power Quality	● Reduced harmonic distortion ● Reduced flicker	● Increased potential for voltage mismatches
Equity	Clean Energy Justice: ● Community solar/wind projects can expand access to renewable power for multi-units dwellings ● Leasing arrangements can expand access	● Potential for increased costs on non-DG customers if public/private costs for serving DG customers exceed benefits ● Cost and marketing challenges for broader access to renewable power

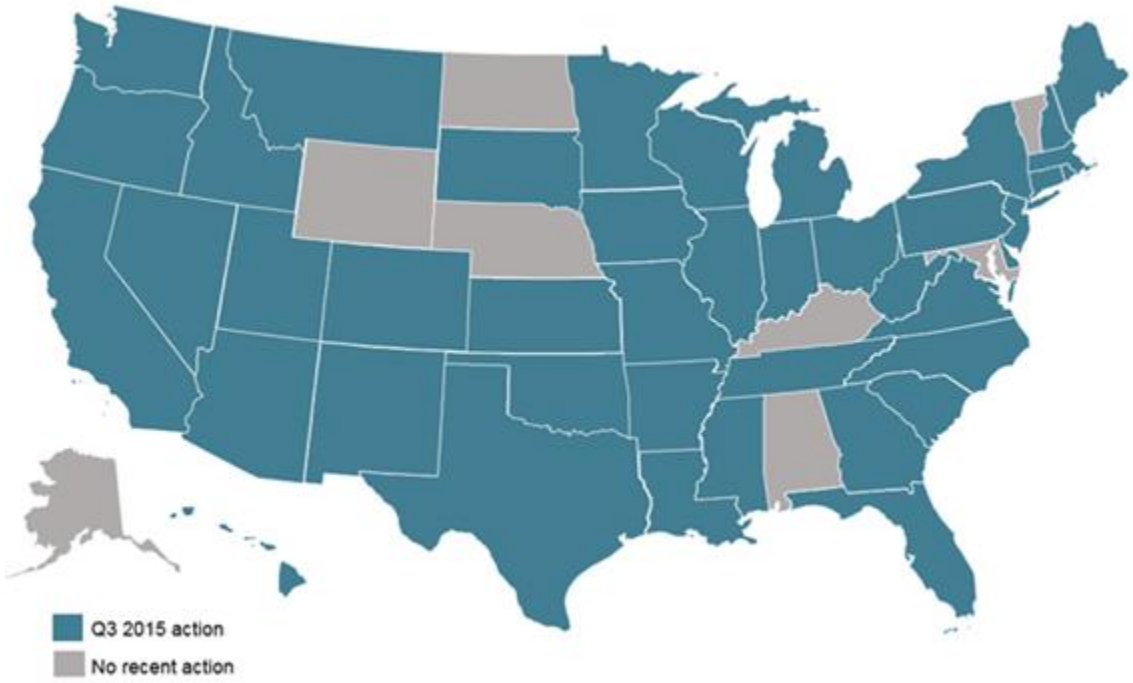
Sources: MIT, 2011; U.S. DOE, 2007; Barrows et al., 2014.

RECENT REGULATORY DEVELOPMENTS

The expansion of distributed PV resources has brought to the forefront the issue of how to properly structure utility rates and PV ownership policies to align solar's costs and benefits among various stakeholders. As of January 2016, 45 states have some form of NEM, and almost all of them took action on NEM, rate design, and solar ownership policies in the third quarter of 2015 (Martin, 2016).

An analysis of recent developments in select states across the country illustrates the complexity involved with trying to address the issue of integrating distributed energy resources into the grid.

Figure 3: Recent Action on Net Metering, Rate Design, and Solar Ownership Policies



Source: Meister Consultants Group, 2015.

Arizona

In December 2013 the Arizona Corporation Commission (ACC) responded to an application from APS to address revenue shifting between DG and non-DG customers, approving a $0.70 per kW monthly charge for all residential DG systems served by APS that were installed after or on January 1, 2014 (NC Clean Energy Technology Center, 2015). In February 2015 the Salt River Project, a municipal utility, voted to add demand charges for new residential PV customers in an attempt to recover more of the costs associated with keeping these customers connected to the grid (Bade, 2015). Unlike IOUs, Arizona's municipal utilities are not under the jurisdiction of the ACC, and therefore are not subject to the state's NEM rules. Later in 2015, both APS and Tucson Electric Power (TEP) proposed new methods for reimbursing NEM customers, with APS seeking to increase the per/kW charge from $0.70 to $3.00, while TEP wanted to pay NEM customers the rate the utility pays for wholesale solar generation rather than the retail rate (Trabish, 2015a). In response to these requests, the ACC voted 4-1 on October 20, 2015 to

conduct a comprehensive analysis of both the costs and benefits of solar (Trabish, 2015b). Hearings will begin in April 2016.

California

In 2013, California passed Assembly Bill (AB) 327, requiring the California Public Utilities Commission (PUC) to develop a new contract or tariff (Trabish, 2016). Under this new tariff, the PUC would have to ensure that there was sustained growth of rooftop PV, while at the same time being fair to all electricity customers. On January 28, 2016, after considering arguments from many stakeholders, including utilities and solar advocates, the PUC voted 3-2 in favor of Net Energy Meeting 2.0, effectively preserving NEM at the retail rate until 2019. In addition to preserving NEM, the decision specifically prohibits "demand charges, grid access charges, installed capacity fees, standby fees, or similar fixed charges on NEM residential customers," while the PUC investigates if these are necessary and how to implement them (CPUC, 2016b). While a previous ruling requires that TOU rates be applied to all residential customers by 2019, it remains to be seen how the PUC will change, if at all, its decision on NEM when it formally revisits the topic in 2019.

Hawaii

On October 12, 2015, the Hawaii PUC filed a ruling that ends NEM for new customers of Hawaiian Electric Companies (HECO). Under the new system, nothing will change for existing NEM customers or those who have already applied for a NEM system and are awaiting approval. In lieu of NEM, the PUC has approved new "self-supply" and "grid-supply" tariffs for connecting DERs to HECO's grid (Pyper, 2015). Under the self-supply option, PV customers in areas with high PV penetration who also have energy storage can qualify for an expedited review and approval of their system. These customers are limited in how much electricity they can export to the grid and receive no compensation for exported electricity. Under the grid-supply option, PV customers can export electricity to the grid and be compensated, but the payments will be at the wholesale rate, which is approximately half of the retail rate in Hawaii. Additionally, all residential PV customers that are still connected to the grid will be subject to a minimum monthly bill of $25.

The filing states that "this is necessary to ensure a smooth transition to a redesigned market-based structure for distributed resources in Hawaii...This evolution in DER policies is essential given the extraordinary levels of distributed renewable energy already achieved in Hawaii, and the State's commitment to meet a 100% renewable portfolio standard by 2045" (HI Public Utilities Commission, 2015). Hawaii has significant levels of PV penetration, with 16% of HECO's customers having PV systems and many circuits having DG account for over 30% of peak load. Although Hawaii's electric system is distinct in many ways from other states, including the fact that its electricity rates are by far the largest in the country, it could provide useful insights for utilities in the contiguous U.S. as they look to address some of the same problems experienced in Hawaii.

Nevada

On December 22, 2015, the Nevada PUC approved an order that triples the fixed charges paid by PV customers over the next four years and reduces the compensation these customers receive for electricity by purchasing excess generation at the wholesale rate instead of the retail rate. In the order the commissioners state that "sending a more accurate price and value signal through the revised rate structure…is more important than creating an inaccurate, false sense of stability" (NV Public Utilities Commission, 2015). Arguably the most controversial decision of the order was to retroactively subject Nevada's 18,000 existing PV customers to the new rules, not just new customers (Pyper, 2016). This decision set off a huge uproar among solar advocates, including announcements by SolarCity, Sunrun, and Vivint that they would have to cease operations in the state. Some critics argue that this decision is a violation of the contracts clause of the U.S. Constitution because it undermines existing agreements between solar companies and electricity customers.

On January 13, 2016 the Nevada PUC chose not to issue a stay on the NEM rule, despite requests from many opponents to their December decision. While the PUC has agreed to review the grandfathering rule, NV Energy filed a proposal on February 1, 2016 to keep NEM for existing customers. In the filing NV Energy proposed to "use September 10, 2015 as the point of demarcation for NEM customers...This represents the last date upon which a NEM customer was included under the 235 MW cap established by SB 374" (NV Energy, 2016). The filing proposes seven different options for dealing with existing PV customers: five offer options for phasing in changes at periods between four and twenty years, and two offer options for delaying all changes for ten or twenty years. It remains to be seen what the Nevada PUC will decide.

* * * * *

While much of the attention around NEM developments has been focused on the western half of the United States, this is an issue that nearly every state is currently grappling with. Lawmakers and utility commissioners are faced with the challenge of balancing efficiency and equity in the midst of a transition to an electric system with fewer carbon emissions and growing shares of DG. There is not one standard solution for addressing this problem. Each state is faced with a different set of circumstances, including the socio-economic standing of its population, strength of PV system output, and its target for renewable energy production levels. Many factors and stakeholders will continue to shape the debate around NEM and incorporating DG into the electric grid, and it remains to be seen how states will tackle this problem moving forward.

FINDINGS

The modeling results provide useful insights for income distributional considerations as state and federal policymakers continue to assess the costs and benefits of alternative rate structures. Overall key findings are reported in addition to separate findings for each rate structure modeled, including additional impacts to residential PV customers created with the implementation of battery storage for the TOU rate, demand charge, and the combination of a TOU rate with a demand charge (see *Methodology* for discussion on battery modeling).

In the tables below, it is important to note the labeling of some results as "INC" for PG&E, PSCo, and NV Energy low load/income customers with a PV system. These customers incurred negative annual bills under the standard rate with NEM because they had a net positive amount of electricity sold back to the grid over the course of the year. When modeling alternative rate structures that produce a positive annual bill for these customers, there is no established mathematical approach for calculating a percent change from a negative value to a positive value, so the "INC" notation is used to show that there was in fact an *increase* in the annual bill.

Standard Rate with Net Energy Metering

The modeling results under the standard rate with NEM produced four useful insights that guide the analysis of other rate structures. First, low load/income customers with a PV system had very low, and sometimes negative, annual bills by selling excess on-site PV production back to the grid. Second, annual bills are significantly higher in APS because of the higher overall load profiles of customers in that state. Conversely, annual bills are lowest in PG&E largely as a result of a more temperate climate helping to reduce overall electricity consumption. Third, the larger the load profile, the more variation there is for annual bills between the across the states. Fourth, the spread of annual bills within each high/base/low category across the five utilities is larger for residential customers without a PV system than those with a PV system.

Table 4: Annual Electric Bills under Standard Rate with NEM

		Annual Bill	
		PV System Status	
		With	Without
APS (AZ)	High	$3,977	$5,895
	Base	$1,710	$3,628
	Low	$2	$1,686
PG&E (CA)	High	$1,785	$3,532
	Base	$752	$2,492
	Low	-$28	$1,255
PSCo (CO)	High	$2,745	$4,528
	Base	$1,096	$2,878
	Low	-$46	$1,369
Eversource (MA)	High	$2,890	$4,231
	Base	$1,461	$2,802
	Low	$80	$1,345
NV Energy (NV)	High	$3,066	$4,919
	Base	$1,240	$3,093
	Low	-$32	$1,460

Fixed Charge

The implementation of a flat $30 fixed monthly charge resulted in large increases in annual bills when starting from a standard rate base, both in dollar terms and as a percentage, for all customers across all five utilities analyzed. Although the dollar impacts on bills from higher fixed charges were the same for all customers, the scale of the percentage change in annual bills is dependent on the load profiles for each state, with the largest percentage changes occurring in the states with the lowest load profiles and, thus, the lowest initial electric bills. Consequently, since low load/income residential customers had the lowest initial bills (and sometimes negative bills for those with PV), the implementation of higher fixed charges created highly regressive results with these customers incurring percentage increases at least three to four times as large as the same increase for their high load/income counterparts.

Table 5: Annual Electric Bills and Impacts of Moving from Standard Rate to Higher Fixed Charge for Residential Customers (with and without PV)

		Annual Bill		Dollar Change		Percent Change	
		PV System Status		PV System Status		PV System Status	
		With	Without	With	Without	With	Without
APS (AZ)	High	$4,337	$6,255	$360	$360	9%	6%
	Base	$2,070	$3,988	$360	$360	21%	10%
	Low	$362	$2,046	$360	$360	20500%	21%
PG&E (CA)	High	$2,145	$3,892	$360	$360	20%	10%
	Base	$1,112	$2,852	$360	$360	48%	14%
	Low	$332	$1,615	$360	$360	INC	29%
PSCo (CO)	High	$3,105	$4,888	$360	$360	13%	8%
	Base	$1,456	$3,238	$360	$360	33%	13%
	Low	$314	$1,729	$360	$360	INC	26%
Eversource (MA)	High	$3,250	$4,591	$360	$360	12%	9%
	Base	$1,821	$3,162	$360	$360	25%	13%
	Low	$440	$1,705	$360	$360	451%	27%
NV Energy (NV)	High	$3,426	$5,279	$360	$360	12%	7%
	Base	$1,600	$3,453	$360	$360	29%	12%
	Low	$328	$1,820	$360	$360	INC	25%

Note: INC denotes customers who incurred negative annual bills under the standard rate with NEM, but a positive bill under this rate structure. There is no established mathematical approach for calculating a percentage change from a negative value to a positive value, so the INC notation is used to show that there was in fact an increase in the annual bill.

Minimum Monthly Bill

Importantly, minimum monthly bills created no impact on annual bills for high load/income customers with PV systems in any of the five jurisdictions examined. For base load/income customers with PV systems, moving to a minimum monthly bill increased annual electric bills by between only $0-$16 for four out of five jurisdictions examined and more than $120 for one jurisdiction (PG&E). Low load/income customers with PV systems, however, faced almost all of the impact of minimum monthly bills – with many modeled households going from negative annual bills (or <$80) under NEM to annual bills of roughly $300 more.

The implementation of a $30 minimum monthly bill resulted in no changes for all residential customers without PV systems. The results confirmed that even low load/income households typically have electric bills greater than $30 each month.

Table 6: Annual Electric Bills and Impacts of Moving from Standard Rate to Minimum Monthly Bill for Residential Customers (with and without PV)

		Annual Bill		Dollar Change		Percent Change	
		PV System Status		PV System Status		PV System Status	
		With	Without	With	Without	With	Without
APS (AZ)	High	$3,977	$5,895	$0	$0	0%	0%
	Base	$1,717	$3,628	$8	$0	0%	0%
	Low	$334	$1,686	$332	$0	18926%	0%
PG&E (CA)	High	$1,785	$3,532	$0	$0	0%	0%
	Base	$876	$2,492	$123	$0	16%	0%
	Low	$303	$1,255	$331	$0	INC	0%
PSCo (CO)	High	$2,745	$4,528	$0	$0	0%	0%
	Base	$1,096	$2,878	$0	$0	0%	0%
	Low	$310	$1,369	$357	$0	INC	0%
Eversource (MA)	High	$2,890	$4,231	$0	$0	0%	0%
	Base	$1,461	$2,802	$0	$0	0%	0%
	Low	$387	$1,345	$307	$0	385%	0%
NV Energy (NV)	High	$3,066	$4,919	$0	$0	0%	0%
	Base	$1,256	$3,093	$16	$0	1%	0%
	Low	$311	$1,460	$343	$0	INC	0%

Note: INC denotes customers who incurred negative annual bills under the standard rate with NEM, but a positive bill under this rate structure. There is no established mathematical approach for calculating a percentage change from a negative value to a positive value, so the INC notation is used to show that there was in fact an increase in the annual bill.

Time-of-Use Rate

Creating different time-based energy tiers with the introduction of a TOU rate alters how tiers operate. Under standard rates, customers face higher energy charges as their energy consumption increases, regardless of the time of day. Like the standard rate, customers are still triggering higher tiers later in the day, but under the modeled TOU rate, energy charges are now lower later in the day after on-peak pricing ends. This means that the energy that used to be the most expensive later in the day once customer usage reached the top tiers is now relatively less expensive given the lower energy charges for all tiers during off-peak periods.

Without Battery

For households with PV systems, the modeled impacts on annual bills were very regressive. Low load/income customers with PV systems saw annual bills increase from negative levels (or very low positive bills) under NEM to between about $60-$135 under TOU rates, which equated to very large percent increases. All high and base load/income customers, on the other hand, experienced net reductions in annual bills, which varied roughly between 15% to 45%. There are two main factors that caused these results. First, low load/income customers with PV systems do not hit the highest tiers like base and high load/income customers, so they do not stand to gain as much as these customers from a transition away from the standard rate to lower energy charges later in the day under the TOU rate. Second, the TOU rate structure includes a $7.70 fixed monthly charge, which similar to the standalone $30 fixed monthly charge (see *Fixed Charge* section), created regressive impacts in changes to annual bills.

For households without PV systems, the impacts on annual bills created by the TOU rate were highly progressive. In terms of percent changes, low load/income customers saw reductions approximately 2-3 times as large as high load/income customers. Overall, all customers without a PV system saw bill reductions anywhere from 10% to 46%. These results largely stem from the fact that customers without PV systems who hit the higher tiers later in the day now face lower overall TOU energy charges for their consumed energy, whereas customers without PV systems with relatively higher loads hit the higher tiers earlier in the day precisely when on-peak TOU rates are in effect. Thus, the relatively lower load customers without PV systems stand to benefit more than those with relatively higher load.

With Battery

These results did not change significantly with the introduction of battery storage. Batteries produced lower bills for nearly all residential customers with PV systems, except for Eversource's low load/income customers and the PSCo's base load/income customers in Colorado who saw extremely small increases in bills (<$8) with the addition of battery storage. Most customers experienced annual bill reductions because the goals of minimizing consumption from the grid and peak shaving were able to reduce purchases from the grid during on-peak pricing periods when energy charges were the highest. However, since the battery dispatch model does not reference the rate structure to achieve price minimization, Eversource's low load/income customers and PSCo's base load/income experienced slightly higher bills.

Table 7: Annual Electric Bills and Impacts of Moving from Standard Rate to TOU Rate for Residential Customers (with and without PV, with and without Batteries)

		Without Battery						With Battery		
		Annual Bill		Dollar Change		Percent Change		Annual Bill	Dollar Change	Percent Change
		PV System Status		PV System Status		PV System Status		PV System Status		
		With	Without	With	Without	With	Without	With		
APS (AZ)	High	$3,377	$5,304	-600.00	-591.00	-15%	-10%	$3,339	-$637	-16%
	Base	$1,291	$2,901	-419.00	-728.00	-25%	-20%	$1,260	-$450	-26%
	Low	$104	$1,073	102.00	-613.00	5834%	-36%	$93	$91	5205%
PG&E (CA)	High	$1,122	$2,699	-662.00	-833.00	-37%	-24%	$1,100	-$685	-38%
	Base	$431	$1,656	-321.00	-836.00	-43%	-34%	$439	-$313	-42%
	Low	$59	$692	88.00	-563.00	INC	-45%	$50	$79	INC
PSCo (CO)	High	$1,972	$3,751	-774.00	-777.00	-28%	-17%	$1,936	-$810	-29%
	Base	$592	$2,001	-504.00	-877.00	-46%	-30%	$562	-$535	-49%
	Low	$70	$746	117.00	-622.00	INC	-45%	$58	$104	INC
Eversource (MA)	High	$2,048	$3,400	-842.00	-830.00	-29%	-20%	$2,013	-$877	-30%
	Base	$817	$1,911	-644.00	-891.00	-44%	-32%	$785	-$676	-46%
	Low	$135	$727	56.00	-619.00	70%	-46%	$138	$58	73%
NV Energy (NV)	High	$2,378	$4,218	-688.00	-701.00	-22%	-14%	$2,345	-$721	-24%
	Base	$803	$2,275	-437.00	-818.00	-35%	-26%	$769	-$471	-38%
	Low	$86	$842	118.00	-618.00	INC	-42%	$61	$93	INC

Note: INC denotes customers who incurred negative annual bills under the standard rate with NEM, but a positive bill under this rate structure. There is no established mathematical approach for calculating a percentage change from a negative value to a positive value, so the INC notation is used to show that there was in fact an increase in the annual bill.

Demand Charge

Without Battery

For households with PV systems, demand charges created impacts on annual bills that were quite regressive. While the impacts on base and high load/income customers were modest (ranging from 0% to 14%) and always slightly increased their bills, the impacts on low load/income customer bills reflected much larger positive increases. Low load/income customers with PV likely faced larger impacts than other customers because the $0.04/kWh reduction in energy charges that come along with the added $10/kW demand charge were insufficient to counteract the bill impacts of the demand charge, precisely because of their low load and the resulting low total energy charges.

For customers without PV systems, demand charges created bill reductions for all customer bills. The bill reductions were distributional neutral across income/load categories – reflecting similar percent reductions in bills between low, base, and high load/income customers that ranged between -3% to -5%. These overall bill reductions likely occurred because the reduction in energy charges produced bills savings that were greater than the added costs of the demand charge – likely due to the higher loads that customers without PV systems have compared to those with systems. The results were consistent between load/income categories because the benefits of lower per kWh energy charges and the costs of the added per kW demand charge are both correlated with load sizes.

With Battery

With the implementation of batteries, there were divergent results for low load/income customers relative to base and high load/income customers. Low load/income customers with a battery in every state experienced higher annual bills with a battery than without a battery under demand charges. This was the case because the grid consumption minimization goal of the battery dispatch likely dominated the impact of peak shaving. Consequently, all low load/income customers with a battery still experienced larger annual bills than under the standard rate. On the other hand, base and high load/income households in all states saw reductions in annual bills with a battery than without a battery. Due to the higher load profiles of these customers, it is likely that the peak shaving goal of the battery created a larger savings impact than from trying to minimize consumption from the grid. Base and high load/income customers saw mixed results when comparing annual bills here to those under the standard rate, with changes ranging from -3% to 4%.

Table 8: Annual Electric Bills and Impacts of Moving from Standard Rate to Demand Charge for Residential Customers (with and without PV, with and without Batteries)

		Without Battery						With Battery		
		Annual Bill		Dollar Change		Percent Change		Annual Bill	Dollar Change	Percent Change
		PV System Status		PV System Status		PV System Status		PV System Status		
		With	Without	With	Without	With	Without	With		
APS (AZ)	High	$3,987	$5,678	$10	-$217	0%	-4%	$3,857	-$120	-3%
	Base	$1,808	$3,492	$98	-$136	6%	-4%	$1,694	-$16	-1%
	Low	$31	$1,618	$29	-$69	1663%	-4%	$68	$66	3763%
PG&E (CA)	High	$1,880	$3,418	$96	-$115	5%	-3%	$1,764	-$20	-1%
	Base	$859	$2,397	$106	-$95	14%	-4%	$783	$31	4%
	Low	$7	$1,199	$35	-$56	INC	-4%	$17	$45	INC
PSCo (CO)	High	$2,812	$4,388	$67	-$140	2%	-3%	$2,684	-$61	-2%
	Base	$1,204	$2,765	$107	-$114	10%	-4%	$1,106	$10	1%
	Low	-$26	$1,310	$20	-$58	INC	-4%	$10	$57	122%
Eversource (MA)	High	$2,912	$4,097	$22	-$133	1%	-3%	$2,790	-$100	-3%
	Base	$1,513	$2,686	$53	-$116	4%	-4%	$1,423	-$38	-3%
	Low	$103	$1,284	$23	-$62	29%	-5%	$133	$54	67%
NV Energy (NV)	High	$3,122	$4,759	$56	-$160	2%	-3%	$2,994	-$72	-2%
	Base	$1,351	$2,976	$111	-$117	9%	-4%	$1,246	$6	0%
	Low	-$17	$1,400	$15	-$60	INC	-4%	$26	$58	182%

Note: INC denotes customers who incurred negative annual bills under the standard rate with NEM, but a positive bill under this rate structure. There is no established mathematical approach for calculating a percentage change from a negative value to a positive value, so the INC notation is used to show that there was in fact an increase in the annual bill.

Time-of-Use Rate with Demand Charge

Without Battery

Overall, the percent changes in bills resulting from a change from standard rates to TOU rates with demand charges very closely mirrored the percent changes seen with only TOU rates for all customers, both with and without PV systems.

For residential customers with PV systems, the combination of the TOU rate and demand charge resulted in bill changes that were quite regressive. All low load/income customers faced large percent increases in bills compared to those under standard rates, while all customers with base and high load/income saw bill reductions of between 15% to 40% off of their original bills under the standard rate. The reason why bill impacts were regressive stems from the combination of regressive bill impacts from the TOU rate and demand charges individually (see individual sections titled *TOU Rates* and *Demand Charges* for more discussion of regressive results for customers with PV systems, but without batteries).

The results for residential customers without a PV system were nearly identical to those under a standalone TOU rate. All of these customers experienced bill reductions compared to the standard rate. Since this rate structure combined the neutral and progressive results seen under the TOU rate and demand charges individually, the net effect on the impacts of this combined rate structure was, not surprisingly, progressive (see individual sections titled *TOU Rates* and *Demand Charges*).

With Battery

With the incorporation of battery storage, all residential PV customers experienced bill savings relative to bills under this rate structure without batteries. Similar to what occurred under TOU rates and demand charges individually, the ability for the battery storage device to shave peaks and reduce grid consumption enabled all of these customers to experience bill savings. Despite the reduction in bills for all residential PV customers with batteries, the overall impacts were still regressive when compared to the standard rate. Additionally, low load/income customers still had larger bills than under the standard rate.

Table 9: Annual Electric Bills and Impacts of Moving from Standard Rate to TOU Rate with Demand Charge for Residential Customers (with and without PV, with and without Batteries)

		Without Battery						With Battery		
		Annual Bill		Dollar Change		Percent Change		Annual Bill	Dollar Change	Percent Change
		PV System Status		PV System Status		PV System Status		PV System Status		
		With	Without	With	Without	With	Without	With		
APS (AZ)	High	$3,387	$5,087	-$590	-$808	-15%	-14%	$3,217	-$760	-19%
	Base	$1,389	$2,764	-$321	-$864	-19%	-24%	$1,241	-$469	-27%
	Low	$235	$1,005	$233	-$682	13257%	-40%	$152	$151	8572%
PG&E (CA)	High	$1,218	$2,584	-$567	-$948	-32%	-27%	$1,076	-$709	-40%
	Base	$550	$1,561	-$202	-$931	-27%	-37%	$461	-$291	-39%
	Low	$152	$636	$180	-$619	INC	-49%	$94	$122	INC
PSCo (CO)	High	$2,038	$3,611	-$707	-$917	-26%	-20%	$1,872	-$873	-32%
	Base	$699	$1,888	-$397	-$991	-36%	-34%	$569	-$527	-48%
	Low	$177	$688	$223	-$681	INC	-50%	$110	$157	INC
Eversource (MA)	High	$2,070	$3,267	-$820	-$964	-28%	-23%	$1,911	-$979	-34%
	Base	$870	$1,795	-$591	-$1,006	-40%	-36%	$745	-$716	-49%
	Low	$230	$665	$151	-$680	189%	-51%	$186	$107	134%
NV Energy (NV)	High	$2,434	$4,058	-$632	-$861	-21%	-18%	$2,271	-$795	-26%
	Base	$914	$2,158	-$326	-$935	-26%	-30%	$772	-$468	-38%
	Low	$198	$782	$229	-$678	INC	-46%	$116	$148	INC

Note: INC denotes customers who incurred negative annual bills under the standard rate with NEM, but a positive bill under this rate structure. There is no established mathematical approach for calculating a percentage change from a negative value to a positive value, so the INC notation is used to show that there was in fact an increase in the annual bill.

Overall Rate Structure Findings

Comparing the results of the SAM model outputs for each alternative rate structure led to a set of overarching findings.

Across all residential customers and rate structures:

- The $30 fixed monthly charge resulted in the largest increases in annual bills from the standard rate, both in dollar terms and as a percentage, for all customers across all utilities analyzed.
- Minimum monthly bills also created very large and regressive impacts on low load/income PV customers.
- While trends in bill impacts were evident across utilities for alternative rate structures, such as the direction of bill changes as a result of a given rate structure, there was notable variation in the magnitude of results between each state.
- For customers with PV systems, all alternative rate structures produced annual bill impacts that were regressive compared to base electric bills under the standard rates.
- The larger the load profile, the more variation there is for annual bills between the states.
- For customers without PV systems, only higher fixed charges produced annual bill impacts that were regressive compared to standard rates, with all others creating annual bill changes that were either distributionally neutral or progressive.

Residential customers without PV systems (always without batteries):

- The combination of a TOU rate and demand charge created the largest dollar reductions in bills for all customers without PV systems.
- Minimum monthly bills resulted in the lowest impact to these customers, as none of them saw increases in annual bills relative to the standard rate.
- The TOU rate produced annual bill impacts that were the most progressive for residential customers without PV systems compared to all other rate structures.

Residential customers with PV systems, but without batteries:

- A demand charge produced annual bill impacts that were the closest to standard rates.

Residential customers with PV systems and batteries:

- The TOU rate generally created the largest dollar reduction in bills for customers with PV systems and with batteries, with the exception of PG&E base load/income customers and Eversource low load/income customers.

The results of this analysis indicate that utilities and regulators considering adopting alternative rate structures, either individually or in combination with one another due to any number of concerns about the economic efficiency or equity impacts of net metering policies, may end up adding new financial burdens onto low-income/load households. Thus, standard rates with net metering appeared to have the least regressive impacts on electric bills for residential customers with PV systems compared to the alternative rate structures examined.

POLICY RECOMMENDATIONS

The findings generated from this study promote two sets of recommendations. One set of recommendations encompasses three guiding principles that policymakers and electricity market stakeholders should consider. The second set of recommendations involves potential functionality enhancements to SAM that would enable more robust simulations in the future.

Recommendations for Rate Structure Decision-Making

1. Consider Location as a Central Factor When Assessing Rate Structure Impacts

Changes in customer bills (both in dollars and percentage terms) can differ significantly across geographic locations for the same load/income category and rate structure. For instance, minimum monthly bills increased annual bills anywhere from $0 to $123 for base load/income residential customers with PV systems. The TOU rate decreased annual bills anywhere from $600 to $842 for high load/income customers with PV systems. Similarly, for customers without PV systems – the TOU rate decreased annual bills between $591 to $833 for high load/income customers.

As a result of the variability in things like geography, load patterns, and characteristics of the local grid (generating mix, capacity, transmission and distribution, etc.), policymakers and energy market stakeholders must assess the specific impacts of any rate structures on their region. For example, PG&E's territory is divided into numerous geographic regions, each having

its own specific set of tiers and energy charges, to more effectively account for the different circumstances the utility faces in serving customers in each region. These differences confirm the necessity for any utility to build into its rate design the specific circumstances it faces not only across its entire service territory, but also within distinct segments of its broader territory.

2. Avoid Rapid Changes to Alternative Rate Structures

The impact on residential customer bills from adjusting rate structures can vary significantly, even within the same geographic region. For instance, in PSCo, a change from NEM to minimum monthly bills increased annual electric bills for low load/income residential customers with PV systems by more than $350, compared to just a $20 increase under a demand charge. The scale of the difference between these results shows how rate structures like minimum monthly bills and fixed charges have the potential to sharply increase annual bills for residential PV customers in a very short timeframe, both in terms of dollar changes and percentage changes. With respect to percent changes in annual bills resulting from a move to an alternative rate structure, it is critical that policymakers first assess the current magnitudes of electric bills for customers to which any change would apply. Policymakers can always adjust the time interval in which customers can fully transition to new rate structures. Rapid changes would violate the established rate design principle of gradualism.

3. Choose a Definition of Equity That Best Balances Overall Goals, And Consider How That Definition Creates Preferences for or Against Certain Rate Structures

Equity is a central criterion for many utilities and regulators when designing rates, but the specific definition used for equity can make a big difference in which rate structure these and other stakeholders view as being ideal. If equity were defined in terms of creating progressive results, then utilities and regulators would need to be aware that all of the modeled rate structures created regressive results for residential PV customers, while only fixed charges created regressive bill changes for residential customers without PV. On the other hand, if equity were defined as creating equal impacts, then a fixed charge could be ideal for all residential customers because it would create equal dollar changes for all residential customers. However, minimum monthly bills and a demand charge could be ideal for residential customers without PV because the percentage impact across the load/income distribution for these customers is roughly equal.

These types of definitions, along with the principle of gradualism discussed in the previous recommendation, make it impossible to make a blanket claim about which rate structure is best at addressing equity considerations. Rather, utilities and regulators should take into consideration which definition of equity is most appropriate for meeting their overall objectives in a given context.

Recommendations for System Advisor Model Enhancements

1. Create SAM Functionality That Allows for Specification of Behavioral Responses

When SAM calculates customer bills under alternative rate structures, it holds electric load constant. Similarly, SAM also assumes identical electricity consumption for customers with and without PV systems for a given geographical area and load category.

However, in practice, the implementation of a new rate structure could induce new behavior from customers responding to the price signals presented by the rate structure. This could involve shifting electric consumption to different times of the day, flattening the peakiness of their load profile, and/or overall reductions in electric consumption. Not all customers will respond to new rate structures in the same way because of different levels of means, awareness, and interest. Likewise, customers who install PV systems may then have incentives to alter their electricity use habits, depending on their rate structure. Additionally, customers who install PV systems may fundamentally differ from non-PV customers in observable or unobservable ways that may impact electricity use.

In order to allow for the generation of results for different kinds of customers with respect to behavioral responses, it would be useful for SAM to allow users to specify behavioral responses from customers under different rate structures. For example, when running the simulation for a demand charge, the user can run multiple iterations of the simulation to test for differences in the customer's level of responsiveness to the price signal presented by this new rate structure. This type of functionality could allow users to specify whether customers respond by trying to minimize consumption from the grid or minimize price. Additionally, as is currently available in the Electric Load section, users could input a scaling factor to suggest how responsive a customer is to different rate structures. Ultimately, this functionality would assist utilities and regulators in understanding how various rate structures may impact revenues due to behavioral responses.

2. Allow Batteries to Reference Rate Structures to Minimize Utility Bills within SAM

Under NEM and standard rates (without time-varying rates), there is no incentive for battery energy storage because the grid essentially serves as a free battery. However, as utilities continue to transition towards alternative rate structures for residential customers with and without PV systems that incentivize time-shifting and load leveling of electricity consumption (i.e. demand charges and TOU rates, or a combination of the two), residential battery storage will likely play a larger role in determining a customer's bill.

SAM currently only allows battery storage to be deployed with the objective of minimizing consumption from the grid, but it would be beneficial to enable SAM to simulate battery storage with the intent of minimizing bills while incorporating the modeled rate structure. There are two main benefits of adding this functionality. First, this would reflect the reality that minimizing consumption from the grid is not always synonymous with minimizing bills. Although under NEM, residential PV customers are incentivized to net out as much of their electricity consumption as possible to lower their bills, other rate structures might make it more economical to shift consumption, rather than simply minimize it, from the grid. Second, allowing batteries to minimize energy charges and/or demand charges would allow for the inclusion of residential customers with battery storage but no PV system. Under the current functionality, enabling a battery storage device has no impact on residential customers without a PV system because they have no ability to minimize consumption from the grid with on-site generation, assuming no behavioral response. If rate structures like demand charges and TOU rates were to apply to all residential customers, it would become increasingly important to understand how battery deployment would affect bills for residential customers with and without PV systems.

CONCLUSION

The findings support the view that there is not one best way to craft rate structures to achieve 'distributional equity.' Defining equity as equal treatment across customers (either in dollar amounts or percentages), progressivity, or gradualism points towards making very different rate structure decisions. The preferences of utilities, policymakers, and other stakeholders in particular regions – along with variations in things like customer base, geography, electricity generation mix, and level of grid development – can support any number of rate structure decisions. Context is vital.

This study assesses the load and income distributional impacts of moving from a standard rate base with NEM to alternative rate structures, either in combination with standard rates or in place of them. While this study refers to the impacts of these changes as regressive, progressive, or neutral, it does not comment on the underlying progressivity or regressivity of the rate structures themselves as that would depend on comparing annual bills to a customer's income, rather than the comparison of annual bill changes to initial annual bills assessed in this study. Further analysis into the overall progressivity or regressivity of alternative rate structures will enable utilities and regulators to make more informed decisions with respect to income distributional equity in the future.

Future Considerations

As briefly summarized in the *Background* section, public debates between utilities, consumer advocates, and other key stakeholders regarding rate design are ongoing at the state and regional levels. However, it is important to understand the context in which these debates are occurring today and how an increasingly distributed future has influenced ongoing rate design debates.

There are active debates within clean energy companies, utilities, independent system operators, and regulatory agencies regarding the future of the electric grid. High future penetrations of residential PV may require systemic changes in how residences interact with the grid; how planning bodies prepare for those changes and operate the grid; and how power generators, distribution, and transmission companies supply power (MIT, 2011). With increasing shares of households owning or leasing rooftop PV systems, installing battery systems to reduce their peak demand, installing other distributed energy resources, and charging electric vehicles during the day or at night – the grid may provide very different services than it currently does today, such as managing backup power and potentially large power flows up and down the distribution system.

This "decentralized" future scenario of the grid may render many of the current public policy debates moot that address compensation rates for power exports back to the grid from rooftop PV customers. With increased reliance on residential batteries and electric vehicles, there would be more on-site demand for the power that residential PV systems themselves generate. As a result, with current levels of electric output from today's small-scale PV technologies, households would likely consume all the power they generate. With little to no exports on an average day for both load and PV production, the challenge of setting rates for energy exported to the grid becomes largely irrelevant, and any residential PV customers' energy consumption from the grid could follow well-established rate structures.

The decentralized energy future is likely not a remote or distant possibility. Experts at U.S. universities, utilities, and independent system operators are actively developing toolkits with which planners and policymakers can help re-design energy systems in their jurisdictions to maximize public value at current and future expectations of the penetration of distributed energy resources (De Martini and Kristov, 2015).

Regardless of which future is in store for power generation, storage, and distribution, today's questions of cost allocation remain pressing.

APPENDIX

SAM Parameters Selected in Analysis

Parameter	Assumption
Solar PV Module	SunPower SPR 210-BLK-U
Inverter	SMA America: SB4000US 240V (CEV 2007)
	Set tilt equal to latitude
System Design	5 kW system, DC to AC ratio = 1.10
Lifetime	Over one year, 0.5% degradation
Battery Storage	Desired bank capacity: 6.4 kWh
	Desired bank voltage: 24 volts
	Battery type: Lithium Ion: Nickel Manganese Cobalt Oxide
	Dispatch model: Peak shaving: 1-day look ahead
Electricity Rates	
NEM	PG&E E-1 Residential Service Baseline Region X, NEM enabled, single meter with monthly rollover credits in kWh, $0.04099/kWh year-end sell rate
Fixed Charges	PG&E E-1 Residential Service Baseline Region X, NEM enabled, single meter with monthly rollover credits in kWh, $0.04099/kWh year-end sell rate, $30 fixed charge
Minimum Bills	PG&E E-1 Residential Service Baseline Region X, NEM enabled, single meter with monthly rollover credits in kWh, $0.04099/kWh year-end sell rate, $30 minimum monthly bill
Demand Charges	PG&E E-1 Residential Service Baseline Region X, NEM enabled, single meter with monthly rollover credits in kWh, $0.04099/kWh year-end sell rate, $10/kW demand charge for peak hourly usage each month, reduced energy charges for all tiers by $0.04/kWh
TOU Rates	PG&E E-6 Residential Time of Use Baseline Region X, NEM enabled, single meter with monthly rollover credits in kWh, $0.04099/kWh year-end sell rate
TOU + Demand	PG&E E-6 Residential Time of Use Baseline Region X, NEM enabled, single meter with monthly rollover credits in kWh, $0.04099/kWh year-end sell rate, $10/kW demand charge for peak hourly usage each month, reduced energy charges for all tiers in all time periods by $0.04/kWh

Parameter	Assumption
Geographic Locations [with typical meteorological year (TMY) data specification]	
Arizona	Flagstaff Pulliam Arpt (TMY3), Phoenix Sky Harbor Intl Ap (TMY3), Yuma Intl Ap (TMY3)
California	Napa Co. Arpt (TMY3), San Francisco Intl Ap (TMY3), San Jose Intl Ap (TMY3), Stockton Metropolitan Arpt (TMY3)
Colorado	Denver Intl Ap (TMY3), Fort Collins (automated weather observing system) (TMY3), Grand Junction Walker Field (TMY3)
Massachusetts	Boston Logan Int'l Ap (TMY3), Martha's Vineyard (TMY3), Plymouth Municipal (TMY3)
Nevada	Elko Municipal Arpt (TMY3), Las Vegas Mccarran Intl Ap (TMY3), Winnemucca Municipal Arpt (TMY3)

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