Title
Electric Utility Rate Design and Transportation Electrification

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A Research Report from the University of California Institute of Transportation

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June 2017

TECHNICAL REPORT DOCUMENTATION PAGE

1. Report No. UC-ITS-2017-49	2. Government Accession No.	3. Recipient's Catalog No.
4. Title and Subtitle Electric Utility Rate Design and Transportation Electrification		**5. Report Date** June 2017
		6. Performing Organization Code
7. Author(s) Nicholas S. Bowden, Ph.D. Candidate, UC Davis		**8. Performing Organization Report No.**
9. Performing Organization Name and Address Institute for Transportation Studies University of California, Davis 1715 Tilia St., Suite 100 UC Davis West Village Davis, CA 95616		**10. Work Unit No.**
		11. Contract or Grant No. UC-ITS-2017-49
12. Sponsoring Agency Name and Address University of California Institute for Transportation Studies		**13. Type of Report and Period Covered** Final Report. January 2017-June 2017
		14. Sponsoring Agency Code UC ITS

16. Abstract
This report outlines the development of an electric utility billing system model for the purpose of evaluating existing and potential electric utility rate schedules. The model was primarily developed to evaluate cost implications of existing and proposed rate schedules on customers charging electric vehicles (EV) but can also be used to evaluate residential electric power bills across a broader context of economic and policy issues. The first issue analyzed in this report is the differential impact of residential default inclining block (tiered) and optional time-of-use rates on the average customer's cost of electric vehicle charging. The analysis shows that the average customer's cost of electric vehicle charging is minimized by the adoption of time-of-use rates. The second issue analyzed in this report is the impact of current demand charges on the bills of commercial customer's using direct current fast charging for electric vehicles.

17. Key Words Electric vehicle charging, Electric utility facilities, Electric vehicles, Benefit cost analysis		**18. Distribution Statement** No restrictions.	
19. Security Classif. (of this report) Unclassified.	**20. Security Classif. (of this page)** Unclassified.	**21. No. of Pages** 35	**22. Price**

Form DOT F 1700.7 (8-72)   Reproduction of completed page authorized

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ACKNOWLEDGEMENTS

DISCLAIMER

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UNIVERSITY OF CALIFORNIA INSTITUTE OF TRANSPORTATION STUDIES

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Executive Summary

This report briefly outlines the structure and purpose of a utility billing system model developed in support of the analysis contained within the report. The model was developed to analyze the electric utility bills impacts of different rate structures currently available and proposed for adoption in the state of California have on consumer expenditure on electric vehicle charging. The report includes the summary and results of two specific analyses currently impacting rate making policy before the California Public Utility Commission. In addition to supporting the analysis of electric vehicle charging cost, it is worth noting that the model facilitates broader analysis of electric rate issues.

The first issue analyzed in this report is the differential impact of inclining block (tiered) and optional time-of-use rates on the average residential customer's cost of electric vehicle charging. The analysis shows that the average customer's cost of electric vehicle charging is minimized by the adoption of time-of-use rates. The average customer is assumed to consume 3500 kWh of electricity for electric vehicle charging over the course of one year. The total cost of electric vehicle charging is $724 under the time-of-use rate and $870 under the default inclining block rate. Switching to time-of-use rate reduces the cost of residential electric vehicle charging by 17% for the average customer under the assumed charging behavior. Under the assumption that the electric vehicle travels 3 miles per kWh, the total cost of charging implies a per mile traveled cost of $0.069. The price per mile traveled of a gasoline powered vehicle is $0.116 assuming the gas price is $2.90 per gallon and the vehicle travels 25 miles per gallon.

The discussion portion of this residential charging analysis attempts to highlight the important elements of rate design and average customer (combined home and EV charging) load that drive the results both qualitatively and quantitatively. Absent any electric vehicle load the average customer would experience a slight increase in their electric bill by switching to time-of-use rates, approximately $40 annually.   The increased load associated with electric vehicle charging increases the average cost per kWh consumed under the inclining block rate due to the nature of the rate structure. The opposite is true, the average cost per kWh decreases, under the time-of-use rate, when electric vehicle load is added if the average customer can charge during off-peak periods. This result illustrates the fact that the average residential customer can decrease their average combined kWh cost by charging their vehicle off-peak. The total cost of electricity can be further decreased if the average residential customer adding an electric vehicle load can shift other household load away from the on-peak period. This behavioral benefit is not available to the average customer taking service under the default inclining block rate.

The second issue analyzed in this report is the impact of current demand charges on the bills of commercial customer's using direct current fast charging for electric vehicles. The issue is analyzed by comparing the annual and monthly bills under current time-of-use electric vehicle rates with demand charges and proposed time-of-use electric vehicle rates without demand charges. The analysis shows the hypothetical direct current fast charging customer's annual bill

under the current time-of-use electric vehicle rate is $11,540 and would decrease to $4,051 under the proposed rate. The proposed rate without demand charges includes increased time-of-use energy charges to achieve to offset the losses in revenue associated with the elimination of demand charges. Despite the increases in the time-of-use energy charges the analysis shows the utility will collect significantly less, $7,489, from the hypothetical direct current fast charging customer.

The direct current fast charging customer is used to illustrate the importance of the principle of revenue neutrailtiy. Revenue neutrality is used to justify the reasonableness of the proposed rates under review in regulatory proceedings before the California Public Utility Commission. Alignment with revenue neutrality relies heavily on the load profile used to calculate annual bills. Historically, the load of all customers within a default class of customers is used to make the calculation. This practice raises the question of the appropriate class to use when the proposed rate applies to a novel class of customers. For instance, the load of all customers receiving service between 20 kW and 200 kW could be used to calculate the revenue neutrality of the proposed electric vehicle rate, because the maximum kW demand of the hypothetical direct current fast charging customer is 50 kW. However, all customers receiving service between 20 kW and 200 kW are not eligible to take service under the new proposed rate, because the rate is exclusively available to electric vehicle charging customers. This reality raises questions about the validity of using the traditional revenue neutrality calculation to justify the reasonableness of proposed electric vehicle rates.

Introduction

This report outlines the development of an electric utility billing system model for the purpose of evaluating existing and potential electric utility rate schedules. The model was primarily developed to evaluate cost implications of existing and proposed rate schedules on customers charging electric vehicles (EV) but can also be used to evaluate residential electric power bills across a broader context of economic and policy issues. This report illustrates how a model can be used to analyze current issues related to EV charging.

The first application analyzes the costs for a residential customer charging an electric vehicle at their home. In this application, the customer is faced with the choice between a default inclining block or "tiered" rate as it is commonly referred to[1] and an optional time-of-use (TOU) rate. The primary finding is that the average customer who charges their EV in the off-peak periods is better off under the TOU rate rather than the tiered rate. The analysis illustrates the potential usefulness of separately metering household and EV loadsand the possibility of billing them differently.[2] This set of circumstances underpins the interest in cost effective submetering options, which is the subject of a pilot program under the jurisdiction of the California Public Utilities Commission (CPUC).

The second application analyzes the electric bill of a hypothetical[3] customer consuming direct current fast charging (DCFC) services. DCFC is considered the public charging option that most closely simulates the refueling of a gasoline engine. The economic feasibility of DCFC has become an issue in the public policy process. The issue revolves primarily around the impact of demand charges[4] on DCFC customer bills. DCFC customers have expressed dissatisfaction with the demand charges because of the high average per kWh cost these charges induce, especially for low load factor loads[5], like charging stations. Two bill estimates are analyzed: one under an existing TOU rate with a demand charge and the other under a TOU rate without a demand charge proposed during the recent SB 350 transportation electrification filings at the CPUC.[6] The simple bill calculations are followed by a discussion of the rate design principles used in the determination of the reasonableness of proposed utility rate schedules. Chief among the discussion is the principle of revenue neutrality and the appropriateness of using the loads from

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[1] The inclining block tariff in California is often referred to as a tiered rate. Block is synonymous with tier, and inclining differentiates the rate schedule from the possibility of a declining block tariff.

[2] This statement only emphasizes the importance of the cost of installing additional metering infrastructure.

[3] Hypothetical here reflects best estimtates from the limited data publically available.

[4] Demand charge generally refers to charges on commercial and industrial customers bill that are the product of some dollar per kW ($/kW) rate and the maximum kW consumption measured during a billing period. Demand charges are different from the more commonly understood energy charges which are the product of some dollar per kWh (dollar per kWh) rate and total kWh consumed by a customer in a billing period.

[5] The load factor quantifies the relationship between a customer's peak consumption and total consumption over some period of time (typically one year). The factor is bound between 0 and 1. A customer who consumed a constant amount of power for the entire period would have a load factor equal to 1. A load will have a low load factor if it consumes large amounts of power, but does so infrequently.

[6] The Southern California Edison Application under A 17-01- includes a proposed TOU rate schedule without demand charges applicable to DCFC.

customers ineligible to receive service under proposed rates in the calculation of revenue neutrality.

Overview of Utility Participation in Transportation Electrification in California

The CPUC's recent involvement in California's broader transportation electrification (TE) policy originates at least as far back as October 2009 when Senate Bill (SB) 626 directed the CPUC to evaluate policies that could remove barriers to widespread EV deployment. The CPUC initiated Rulemaking 09-08-009 in response to the bill.[7] A Rulemaking is the CPUC's formal process used to gather information, interpret current regulations application to policy and to amend or propose new regulations as appropriate. This initial rulemaking procedure resulted in a number of CPUC Decisions. First, the CPUC determined that selling EV charging services did not make the entity a public utility. This determination has a significant implication, a public utility is subject to CPUC price regulation and therefore EV charging services sold by non-utility operators are not price regulated by the CPUC. Another CPUC Decision determined the rules for cost allocation for distribution system upgrade associated with new EV loads, directed future utility EV rates, and prohibited public utilities from owning electric vehicle service equipment (EVSE).

In March 2013, CPUC's role in EV policy was reaffirmed through Executive Order B16-2012. The Executive Order directed the CPUC to help build out infrastructure to support 1 million zero-emission vehicles within the State of California. Following the Executive Order, the CPUC initiated a second rulemaking, Rulemaking 13-11-007 in November 2013. An important Decision reversed the previous conclusion that public utilities could not own EVSE infrastructure (e.g., EV chargers). A scoping memo and ruling made in July 2014 initiated the first public utility infrastructure applications for CPUC consideration. Between April 2014 and February 2015, the state's three largest investor owned utilities (IOUs), Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E) and Southern California Edison (SCE), filed applications to deploy approximately $1 billion in distribution system and EVSE infrastructure.[8] The infrastructure programs outlined in these filings targeted multi-unit dwellings and workplaces with specific requirements for investments in disadvantaged communities. The size of the initial applications resulted in CPUC Decisions which ordered a phased approach with combined first phase approvals in infrastructure investment to be followed by second phase applications to extend these pilot programs at a later date.

Utility EV infrastructure deployment received further direction in October 2015 when SB 350 directed electric utilities to file infrastructure applications for transportation electrification. In response, the three large IOUs filled applications in January 2017.[9] Those applications included a combination of smaller priority review infrastructure projects and larger longer term standard

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[7] The Docket Cards for Rulemakings and other proceedings at the CPUC can be found here. Docket cards link to the documents submitted by parties to the proceedings and the decisions reach by the CPUC.

[8] Those three applications were filed under Dockets A14-10-014, A14-04-014 and A17-02-009.

[9] Those three applications were filed under Dockets A17-01-020, A17-01-021 and A17-01-022. Additional information surrounding SB 350 activities at the CPUC and links to the dockets can be found at http://www.cpuc.ca.gov/sb350te/.

review projects. Two IOUs, PG&E and SCE, included standard review projects which focused on infrastructure to support medium- and heavy-duty vehicle electrification. SDG&E's standard review project proposal focused on infrastructure for single family home and smaller multi-unit dwellings. In April 2017, the CPUC issued a scoping memo consolidating the three proceedings and setting a timeline for accepting responses on different issues and forecasting expected dates of decisions.[10] The timeline generally groups filing dates by vehicle charging application, residential, medium/heavy duty and direct current fast charging. In addition to infrastructure planning, each deadline includes rate design as a formal issue for each charging application.

The Utility Billing System Model

The model developed for this research project simulates a utility billing system with the purpose of evaluating rate design questions associated with different EV charging applications.[11]

The model simulates the monthly cost for one household using hourly load data.[12] The model can be used to estimate the cost of EV charging separate from additional load or household plus EV load, for charging applications where a single meter is used to bill both loads. The combined metering of building (or household) load and EV load is of particular interest in the residential sector and smaller commercial applications where the investments in separate metering infrastructure comes at a high cost relative to electric power consumption cost. The model aggregates the hourly load to monthly load for each source of load (i.e., building or household load and EV load) independently and combines them. The building, EV, and combined loads are primary outputs of the model.

The current version of the model allows the calculation of monthly bills based on several rate designs. Rate designs compatible with the model include flat, block (i.e., tiered), and TOU rates. The model allows the rates to change on a monthly basis to handle the winter and summer variation in rates common in many electric utility schedules. In addition to calculating monthly bills based on total energy or kWh consumed, the model also identifies the maximum load which occurs in each month to allow the incorporation of demand charges into the bill calculation.

The calculation of bills based on flat rates is simplest. For flat rate schedules, the model aggregates the hourly load in each month separately and applies the flat dollar per kWh for each month to every kWh consumed in the month. The flat dollar per kWh rate is set as a parameter within the model. The calculation of bills for tiered or block rates were incorporated on the second iteration of the model. The utility billing system model includes optional parameters for setting the kWh levels at which the dollar per kWh rate will change so as to reflect a specified block rate schedule. For instance, California default residential rate schedules use inclining block rate design and define the" first tier using the concept of a baseline kWh per day to meet basic needs. In order to calculate the baseline kWh per month, the model counts the number of days

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[10] The Scoping Memo and timeline can be found in the Docket card of any of the three filings because of consolidation.

[11] The utility billing system model consists of a series of modules developed in the Python programming language.

[12] The data was retrieved from Southern California Edison. It is the hourly arithmetic mean of the residential customer class, for 8760 hours or one year.

and multiples it by the daily baseline allocation. This value represents the first "step" in the inclining block rate schedule. If consumption falls below this kWh value, then the first block dollar per kWh rate is applied. A second block is established in the default residential schedule in California by multiplying the baseline block by four. If consumption falls between the baseline kWh and four times the baseline, then the second dollar per kWh rate applies and above that value a third dollar per kWh rate applies. The utility billing system model captures the combined monthly load and through a series of logical "if" statements, calculates the monthly bill by summing the products of dollar per kWh rates applicable to the amounts of load within each block.

Finally, the utility billing system model allows for the calculation of bills associated with TOU rates. The model assigns the load from the input file into different TOU categories based on TOU period parameters set within the program. For instance, a TOU rate might specify an on-peak period between 2:00 pm and 8:00 pm and an off-peak period for the rest of the hours. The modeler would specify these time parameters as the start and end of a TOU period and the model would sum the values of load falling between these hours as it reads the load input file for each month. The remaining load would be summed into a separate category. The two separate sums would then be multiplied by the rate parameter related to the TOU period and then summed together to yield the monthly bill. The TOU structure in the model can be generalized to accomadate any combination of TOU periods, but the basic computational logic remains the same.

In summary, the model uses monthly load and rate schedules as inputs and as an output produces hypothetical monthly utility bills. These outputs are useful for the analysis of customer costs and regulatory questions associated with transportation electrification. In addition, the basic computational design of the utility billing system model can be applied more broadly to questions of rate design in the electric utility industry.

# Application 1: Residential EV Charging

Economic theory of competitive markets assumes that producers and consumers have access to perfect information and actively apply that perfect information to make optimal decisions. The accuracy of this assumption in the case of residential customers in electric power consumption decisions has been studied academically and is questioned more generally based on practical experience. The pervasiveness of electric power consumption in every day activity and the potential complexity of rate design underlie the practical conclusion that individuals, especially in the residential customer class, do not have or use perfect information when making electric power consumption decisions. In addition, the consumption of electric power for electric vehicle charging involves the calculation of cost over a long time horizon prior to or at the time of vehicle purchase. In general, consumers, policy makers, and EV manufacturers are concerned about the ability for residential customers to make optimal decisions. The following application is an illustration of the complexity of the decision to purchase an EV which is exacerbated by the secondary choice between two electric power schedules available to residential customers in

California. Currently, residential customers in California's three largest IOU service territories are placed by default onto an inclining block or tiered rate schedule with the option to opt into a TOU rate schedule.

Defining Average Residential Consumer

The base case used for the analysis of residential EV charging is based on assumptions made about the average residential consumer. The average residential customer is defined by the average hourly residential load profile, which is calculated by summing the electric load in each hour for all residential customers metered in a utility service territory and dividing each hourly load by the number of residential customer classes. The analysis in this application will be based on the average residential customer in the SCE service territory.[13] The average residential customer in the SCE service territory consumes 6,619 kWh annually or an average of 551.6 kWh per month. A simple average monthly load is misleading because the average residential customer's monthly load varies between 432 and 801 kWh per month. The monthly load of the average residential customer in SCE service territory is illustrated in Figure 1.

Figure 1: Average Residential Customer Monthly Household Load
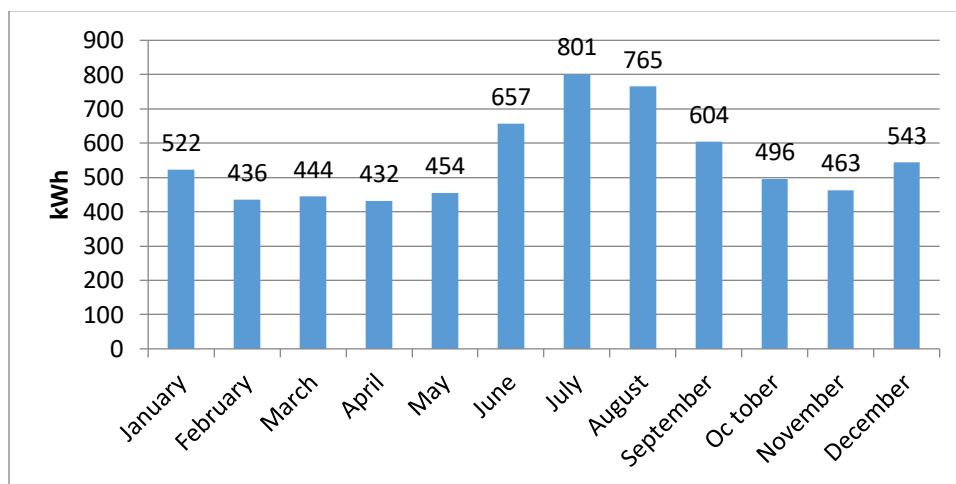

The total monthly load is a sufficient statistic for calculating both flat rate and block rate schedule bills, but does not contain the necessary information for calculating a customer's bill using a TOU rate schedule. The TOU bill implications for a residential customer's consumption behavior are dictated by the hourly profile of the customer's load. Figure 2 shows the hourly load of the average customer for a representative winter, spring, summer and fall weekday.[14]

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[13] SCE provides a csv file with hourly average residential load profile on its website under Regulatory Information: SCE Load Profiles: SCE Dynamic Load Profiles. The customer class used in this analysis is listed under Domestic. The link is here.

[14] In order to control for additional causes of variation each day selected is a Tuesday and extreme cases due to weather conditions were investigated and eliminated. Specifically, the days are January 19, April 19, July 19 and October 18 of 2016.

Figure 2: Average Residential Customer Hourly Household Load
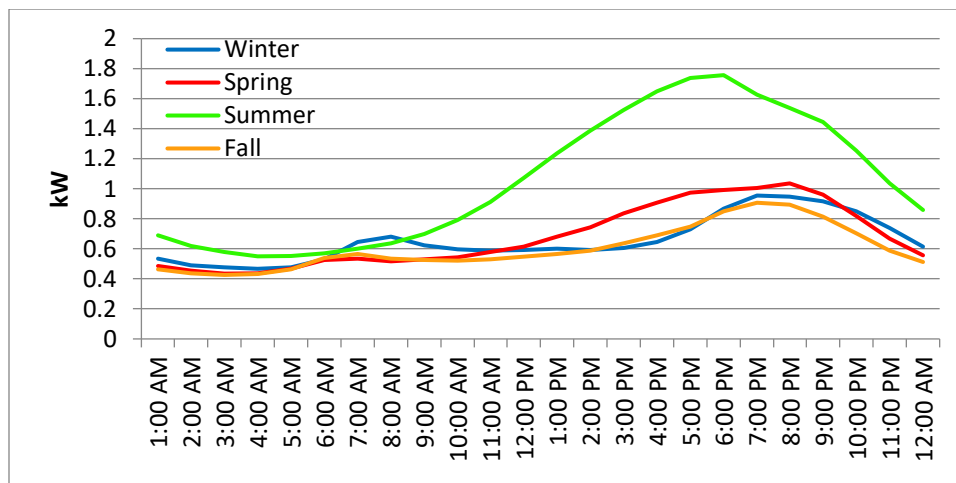
There are several important observable characteristics of the daily load profiles which are illustrated in Figure 2. First, the residential household load peaks in the evening in all seasons, although the summer season peak is noticeably earlier, one or two hours. The summer peak load is also significantly larger than the load in other seasons, approaching twice the other seasons. The winter load profile includes a second smaller peak in the morning hours. The load profiles are driven primarily by the environmental conditions (i.e., ambient temperature and daylight) as well as behavioral patterns shaped by average working hours. The daily household load profiles of the average residential customer are of paramount importance when considering the impacts of a TOU rate structure.

Defining Average Residential Electric Vehicle Load

In addition to the hourly household load profile, an hourly annual electric vehicle charging profile is a primary input into the utility billing system model. The development of an average residential electric vehicle charging load profile is a challenge due to data availability with the primary reason being there are very few separate metering of EV loads. The upfront cost and time required to install an additional utility grade meter required for separate billing of the EV load is the primary deterrent of separate metering. Therefore, the vast majority of electric vehicles charging load at residential locations is metered together with household load and therefore can not be easily and accurately identified. For instance, in 2016, the CPUC residential EV Load Research Report identified the existence of 202,000 EVs registered in the service territories of the three largest IOUs, but those same IOUs reported only 1,200 separate meter single family residential EV accounts.[15] For this study, the EV load profile is developed using the data available from the separate meter single family residential EV accounts for three reasons: 1) the data is available, 2) it is based on observed behavior, and 3) it reflects near-optimal EV charging behavior given the EV rates applicable to those loads. The near optimality of the behavior given applicable rates,

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[15] CPUC 2016 Load Research Report can be found along with other CPUC TE information at http://www.cpuc.ca.gov/zev/.

allows the comparison of the two residential rate schedules available to residential customers, assuming the residential customer is minimizing EV charging cost. Specifically, the EV profile assumes charging at 1.44 kW on the weekdays and 1.08 kW on the weekends, for the seven hours between 8:00 pm and 3:00 am in both instances. This daily charging profile results in the total annual consumption of 3,500 kWh.[16] Under the assumption of three miles per kWh, the corresponding residential customer travels 10,500 EV miles.[17] The EV charging profile used for the analysis is shown in Figure 3.

Figure 3: Residential Customer Hourly Electric Vehicle Load
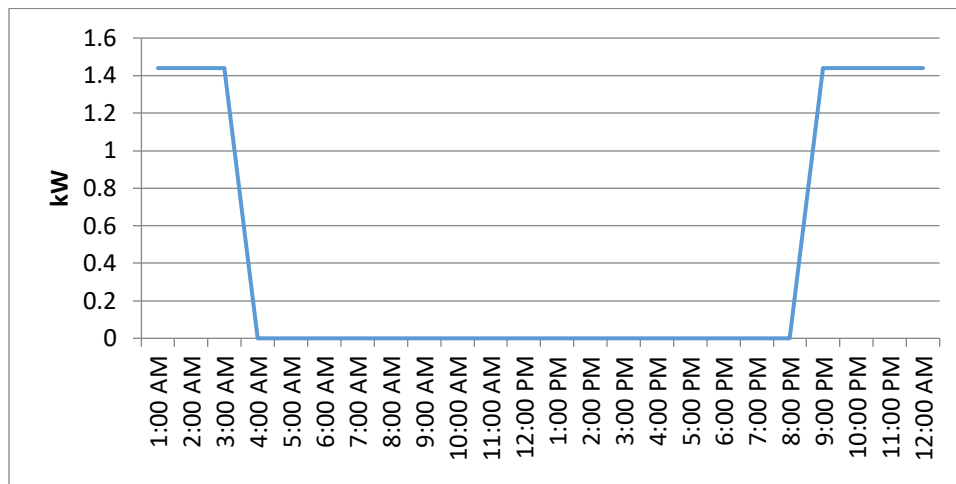
The load profile of the separately metered customers shows a high level of elasticity of residential EV load to the price of electricity. Given the availability of charging timers in most EVs or EVSE, residential customers using separate meters have shown the ability to delay charging until the beginning of the super off-peak TOU price periods set in the IOU's TOU EV rate designs.

Residential Rate Design

The average residential customer who does not purchase a separate utility grade meter has two primary options for purchasing electric power for their combined household and EV load: 1) default inclining block rate and 2) optional TOU rates. Specifying the correct rate parameters needed to compare the billing impacts of these two rates schedules includes one additional complexity in the SCE service territory. The three large IOUs in California differentiate their billing determinants within each rate schedule by geographic sub-region. SCE baseline region 16 was chosen for the following analysis based on a combination of factors, including population, geography, and because its baseline is near the average of all baseline allocations.. The decision was made in order to best match the use of the average residential load profile to the necessity

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[16] For more information on EV charging behavior see the California Air Resources Board Advanced Clean Car Midterm Review Appendix G.

[17] Three miles per kWh is a realistic, but conservative estimate given the EPA estimates of fuel economy. For more on EPA estimates of fuel economy use the EPAs fuel economy tool at http://www.fueleconomy.gov/feg/findacar.shtml.

of choosing a single regional baseline allocation for billing calculations. The baseline allocation for region 16 is 12.1 kWh and 10.8 kWh per day in the summer and winter months respectively. These baseline allocations are important parameters in both the default inclining block and TOU rate schedules. The use of the baseline allocation is intended to reflect a minimum electricity usage for meeting basic needs (e.g., lighting, cooling) and its use in the model is discussed further in sections that follow. Also important to the calculation of bills under both rate schedules is the definition of winter and summer months. In the SCE tariff, summer months are defined as June, July, August and September, and all other months are defined as winter for the purpose of bill calculations.

Inclining Block (Tiered) Rate Schedule

The inclining block or tiered rate schedule is the default residential rate for all three of the large IOUs in California. The defining feature of the inclining block schedule is the rate, dollar perkWh, which increases at discrete kWh levels of consumption within a billing cycle, approximately one month. In California, the kWh levels which define the blocks are derived from an administratively set daily kWh baseline allocation. In June, for example, there are thirty days, and June is a summer month, so the baseline allocation in region 16 for the month of June is 363 kWh (30 × 12.1 kWh). The baseline allocation defines the upper bound for the first block or tier of the inclining rate structure. All kWh consumption between zero and 363 is billed at the first and lowest tier rate, $0.16317/kWh. In the SCE inclining block rate schedule for region 16 in the month of June, the beginning of the second block or tier is defined by the end of the first block (i.e., 363 kWh) with the upper bound being four times the baseline allocation or 4 × 363 kWh = 1452 kWh. The kWh consumed between 363 and 1452 is multiplied by the second tier rate, $0.24864/kWh.[18] The third and final block is defined as all kWh consumed over 1452 for the month of June in region 16. The final and highest rate, $0.31362/kWh, is multiplied by all the kWh metered above 1452. Similarly, a thirty day winter month has discrete blocks separated at 324 kWh and 1,296 kWh. Only the levels of kWh at which the inclining rates apply vary while the rates themselves do not change with the summer and winter months. Again , the inclining rates applicable to the three seasonal blocks are $0.16317/kWh, $0.24864/kWh and $0.31362/kWh. Figure 4 illustrates the summer and winter inclining block rate schedule for SCE graphically.

Figure 4: Residential Inclining Block Rate Schedule

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[18] Here the if logic of the utility billing system model can be illustrated. If the total monthly consumption is less than 363, then multiply all monthly kWh by the lowest dollar per kWh and that is the bill. If the total kWh is greater than 363, but less than 1452, multiply the total monthly kWh minus 363 by the second dollar per kWh and 363 by the lowest dollar per kWh, sum them and that is the bill. Extend this logic one more iteration to understand how the bill is calculated if monthly kWh is greater than 1452. The model logic is generalized such that one set of if-statements allows the operation to take place for each month.
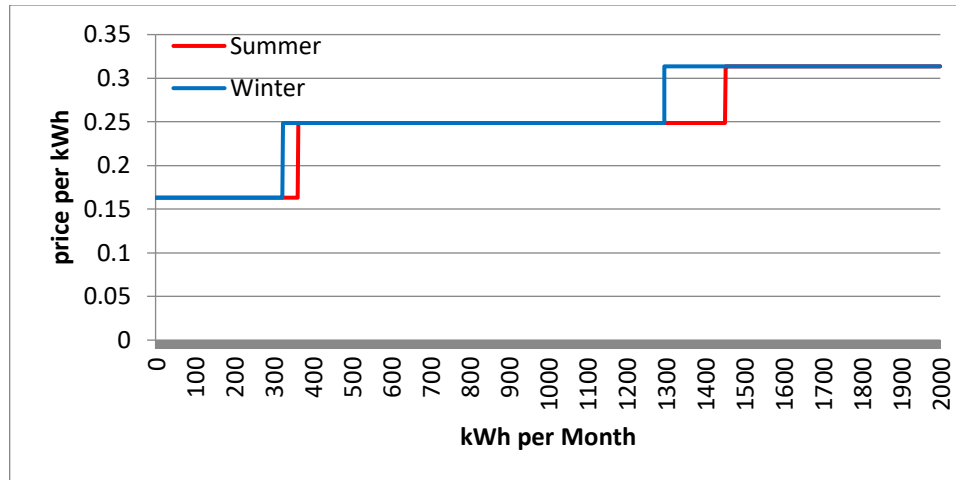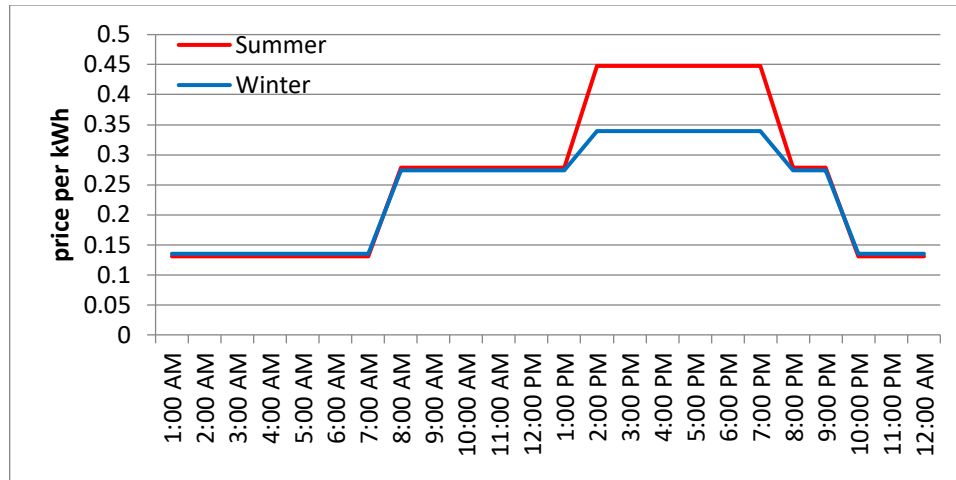
Time-of-Use (TOU) Rate Schedule

The TOU rate schedule is available to all residential customers who have a digital meter capable of interval metering at their location. These meters were deployed ubiquitously in the three large IOUs in California and the rates are therefore available to all residential customers.[19] The defining characteristic of any TOU rate is the billing of kWh consumed at different time periods at different rates. For instance, SCE's residential TOU rate has three time-of-use periods, super off-peak, off-peak and on-peak. The TOU periods are defined by the hour in which the period begins and ends. In both summer and winter months the TOU periods are defined by the same hours. The super off-peak period begins at 10:00 pm and ends at 8:00 am every day of the year. The off-peak period begins at 8:00 am and ends at 2:00 pm and resumes at 8:00 pm and ends again at 10:00 pm every day all year. The on-peak period begins at 2:00 pm and ends at 8:00 pm all weekdays and non-holidays. The remaining hours, specifically, 2:00 pm to 8:00 pm on weekends and holidays are defined as off-peak hours. The TOU rates that apply to those TOU periods vary across the summer and winter months. In summer months the super off-peak, off-peak and on-peak rates are $0.13076/kWh, $0.27887/kWh and $0.44786/kWh respectively. In the winter months, the super off-peak, off-peak and on-peak rates are $0.13503/kWh, $0.27393/kWh and $0.33929/kWh respectively. The TOU rate schedule also includes a baseline credit mechanism. This mechanism applies a credit (i.e., reduction in bill) in the amount of the monthly baseline allocation, described in terms of the first block in the inclining block rate schedule, multiplied by the credit rate. The baseline credit rate for the TOU rate schedule is $0.09146/kWh.[20]

Figure 5: Residential TOU Rate Schedule

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[19] Here is the deployment schedule for SCE http://www.energy.ca.gov/load_management/documents/2008-05-27_workshop/presentations/Southern_California_Edison_SmartConnect.pdf

[20] For example, the baseline allocation for June in region 16 is 363 kWh. Given the baseline credit rate of $0.09146/kWh, the baseline credit for June is 363 kWh*$0.09146/kWh = $33.199.

The important empirical characteristic of the TOU rate schedule is the greater rate, dollar per kWh, during the on peak period. The higher retail residential rate is correlated with higher residential and total system loads experienced during this 2:00 pm to 6:00 pm time period. These higher system loads require the use of higher cost generation resources and the TOU rate schedule reflects this fact. Similarly, off-peak and super off-peak time periods reflect the lower costs associated with lower system load which allow the use of lower cost generation resources.

Analysis and Results

The analysis in application 1 was motivated by claims that the cost of EV charging does not provide the fuel cost savings relative to gasoline vehicles consumers are expecting. This analysis addresses the information requirements necessary for residential consumers to form appropriate expectations about the cost of EV charging. The reasons why consumers might have bad information concerning the cost of EV charging is an interesting question, but beyond the scope of this report. The analysis proceeds in two steps. The first step utilizes the utility billing system model to compare the two rates available to residential customers (i.e., inclining block and TOU rate schedules described above) in order to determine the customer's optimal rate.[21] The second step compares the cost per mile of EV fuel to the cost per mile of gasoline fuel.

Empirical Facts Driving Results

Before presenting the results, it is helpful to outline the empirical facts that are driving the results in the first step. First, the inclining block rate does not apply differential rates to kWh consumed in different time periods, and therefore the temporal distribution of consumption has no impact on the consumer's bill. The only factor which determines the consumer's bill under the inclining block tariff is the total monthly kWh consumption. On the other hand, the TOU rate schedule will bill the residential consumer different rates for consumption that falls into the different time periods. This has important implications for the average residential customer. Specifically, the average residential customers load profile is positively correlated with the system load and

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[21] If SCE service territory smart meter deployment was completed in 2012, and only customers who opted out of smart meter installation do not have the metering infrastructure necessary to access the TOU rate schedule.

therefore positively correlated with the TOU rate structure. Therefore, the average residential customer's greatest kWh consumption happens at the same time as the greatest dollar per kWh price. Figure 6 illustrates this fact graphically.

Figure 6: Residential Load and TOU Rate Schedule Correlation
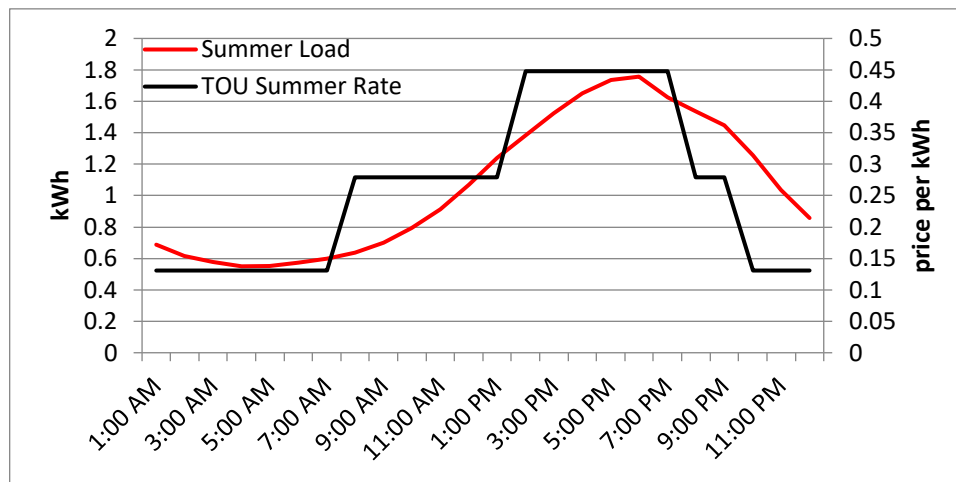
The inclining block rate schedule is the default tariff, and the following analysis assumes the average customer is taking service under this rate schedule at the time the bill calculations are made. The rate schedule a residential customer receives service under at the time of the decision to purchase and subsequently charge an EV is important in determining the cost of charging an electric vehicle, especially if the customer chooses to change rate schedules. This point is illustrated by the impact switching from the inclining block to TOU rate schedule has on the residential customer when only the household load is considered (i.e. no EV load is metered or billed). If the average residential customer resides in region 16 of SCE service territory and takes service under the default inclining block rate, then their annual cost of household electricity is $1294.[22]

If the same average customer switched to the TOU rate schedule, then their annual cost of household electricity would increase to $1401, an increase of $107. Therefore, the average residential customer is worse off when they switch to a TOU rate if no change in their load profile occurs. For simplicity in the analysis that follows, the assumption of no change in the household load profile is made. [23]As stated above, EV charging load is assumed to be nearly optimal, all EV charging happens in the super off peak period with the exception of two hours of charging in the off-peak period. The near optimality of EV charging is illustrated in Figure 7.

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[22] The current version of the utility billing system model omits the daily meter charge of $0.031 per day. Therefore the total annual cost is 365 days ×$0.031/day = $11.32 greater per year. This cost is the same for inclining block and TOU rate schedules and therefore does not affect the validity of the relative comparisons made here in.
[23] It is reasonable to believe a household on a TOU rate would change their behavior, i.e. load profile, but this would complicate the comparison.

Figure 6: Near Optimal EV Charging Load
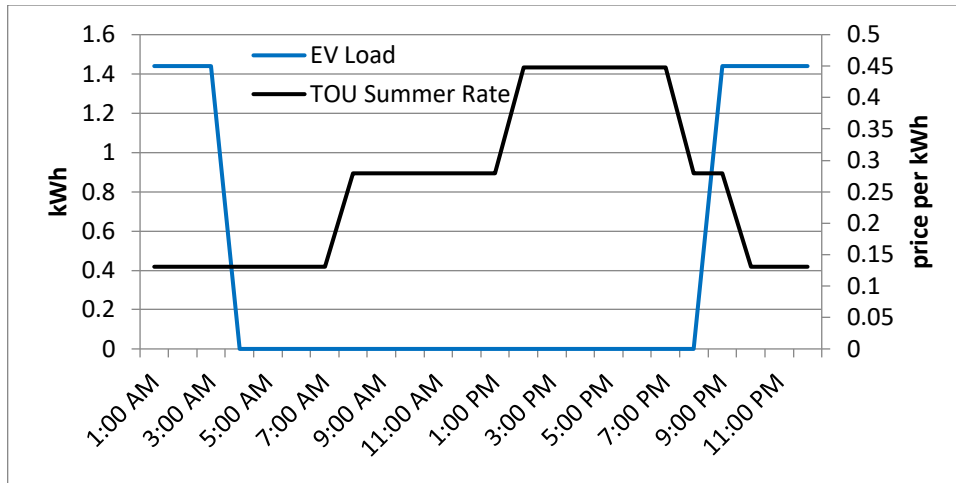
Residential EV Bill Calculation Comparison

The total annual cost of combined household and EV load under the inclining block rate schedule for the average residential customer is $2165. The same combined load results in an annual cost of $2018 under the TOU rate schedule.[24] Therefore, the optimal decision is for the average residential customer to switch to the TOU rate when they purchase an EV and charge it at home because the total cost of electricity is $147 lower. The total annual cost for electricity is lower under the TOU rate despite the higher cost in the summer months. The relative monthly bills for the average residential customer under the two different rate schedules are illustrated in Figure 8.

Figure 8: Monthly Bills

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[24] The utility billing model does not include differential treatment of weekend metered load and therefore overestimates the annual TOU bill by approximately $71, 34 days*1.5 kWh/hour *6 hour/day *0.17$/kWh + 66 days*6 hour/day*0.8kWh/hour*0.6$/kWh = $52 + $19 = $71, where $52 is the total reduced cost across the four summer   and 19 is the total reduced cost across the eight winter months, i.e. $13 per summer month or $2.3 per winter month.
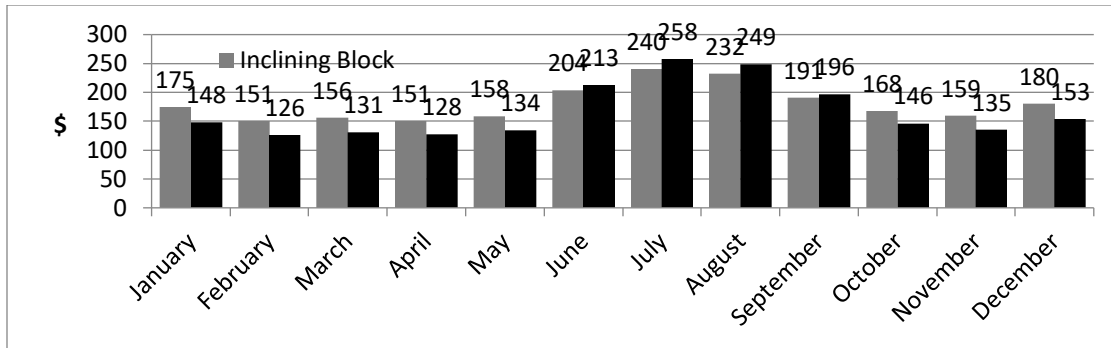
In addition to comparing the total bills, the individual components of the bills can be analyzed. Under the TOU rate schedule, the cost of EV charging is clear because each kWh is associated with a specific rate, dollar per kWh, based on the hour of the day in which that kWh is consumed. The direct association between kWh and rate allows an unambiguous analysis of combined EV and household load and the cost of EV or household load in the absence of the other.

There are at least two ways of allocating the total monthly bill to specific kWh of consumption, (i.e., EV or household) when a residential customer takes service under the inclining block rate schedule. The choice of allocation mechanism has important implications for the comparison of electric and gasoline fuel costs. The first way is to allocate the cost chronologically. This method would start in the first hour of the month and allocate the first X kWh consumed as time elapses to the first block. The value X is the discrete level at which the first block ends (e.g. X = 363 kWh in June in this application). These X kWh would be allocated the cost of the lowest rate (e.g. $0.16/kWh in June). The next Y kWh consumed could be allocated to the second block (e.g. between 363 and 1452 kWh in June). The cost of these kWh could be assigned the rate of the second block (e.g. $0.248/kWh in June). The remainder of the kWh, those beyond X + Y, could be allocated to the third block and assigned the highest dollar per kWh rate (e.g. $0.31/kWh in June). Simply speaking, this method allocates the kWh consumed later in the month to the higher dollar per kWh rate blocks.

The second way to allocate the cost to specific kWh of consumption (i.e., EV and household load) is to first allocate all household consumption to the lowest blocks and then allocate the EV charging load after the household load is allocated. This results in the maximum cost of EV charging load given the total combined load. This study will consider this second form of cost allocation. The strength of this allocation of cost is based on the logic driving a customer's decision to purchase an EV and on the customer's perception of the cost. When the consumer analyzes the decision to purchase an EV or not, the cost of adding the electric vehicle charging will be the difference between the cost when no EV load is present and the cost when household and EV load are present together. The second allocation method yields this difference in the total residential electricity bill. The relative monthly cost of EV charging under the two rate schedules is presented graphically in Figure 9.

Figure 9: Monthly EV Charging Costs
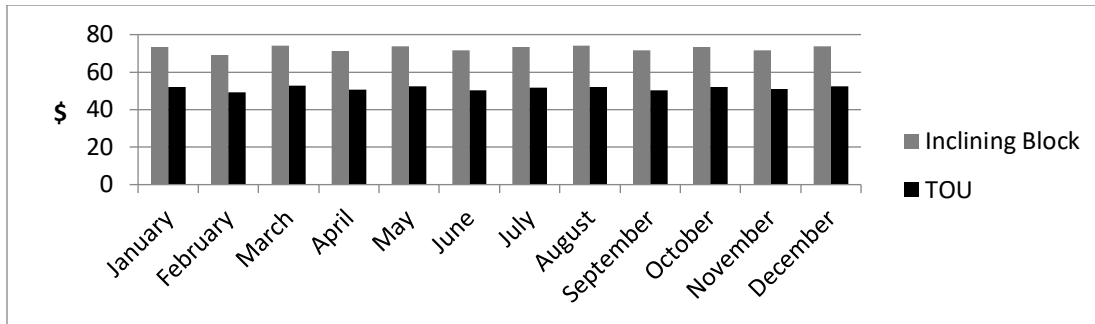
The monthly EV costs drive the superiority of the TOU rate in this application 1. The total cost of EV charging is $870 under the inclining block rate schedule and $617 under the TOU rate schedule. The difference of $253 dollars is equal to the sum of the differences between the household load cost and total load costs described above.[25]

While the cost of EV charging is $617 under the TOU rate, this value is not the full cost of EV charging when the average residential customer was originally taking electric service under the default inclining block rate. The full incurred cost of charging an EV that the residential customer perceives and actually incurs is the cost of EV charging plus the cost of switching, $617 + $107 = $724. Similarly, the initial cost of electricity for the average residential customer was $1294, and after adding EV charging load and switching to the TOU rate, the average customer's annual cost of electricity increased to $2018. The difference is $2018 - $1294 = $724. As expected, this cost is still less than the $870 cost of EV charging under the default inclining block rate.

Electrical and Gasoline Fuel Analysis

The next step of the analysis is the comparison of the cost of charging or fueling relative to a gasoline internal combustion engine (ICE). Assume that the EV in question has a fuel efficiency of three miles per kWh, which implies 10,500 miles per year given the 3,500 kWh consumed in the model. Given the total cost of $724, the average cost is $0.069/mile. Assume the alternative is a similar ICE automobile with 25 miles per gallon and the average cost of gasoline in the SCE service territory is $2.90.[26] Under these assumptions, the average cost for the ICE is $0.116/mile. This analysis predicts a 40% fuel cost savings for the average residential customer who switches from and ICE vehicle to an EV.

If fuel economy of the ICE were to increase to 40 miles per gallon, then the cost would be $0.0725/mile. If the fuel efficiency of the ICE did not change, but the price of a gallon of regular gasoline fell to $2.00 per gallon, then the cost of the ICE would be $0.08/mile. If both the fuel efficiency and cost of a gallon fell by the amounts above, then the cost of the ICE would fall to $0.05/mile, less than the fuel cost of the EV.

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[25] The difference between the TOU and inclining block household load costs is ($1401 - $1294) + ($2165 - $2018) = $107 + $147 = $254. Rounding error explains difference between $253 and $254.

[26] Quality data on metropolitain gasoline prices can be found at https://www.eia.gov/petroleum/data.php. On June 26, 2017, the EIA reported a price of $2.90 for regular gasoline in the Los Angeles metropolitan area.

Figure 10: EV versus ICE Fuel Costs
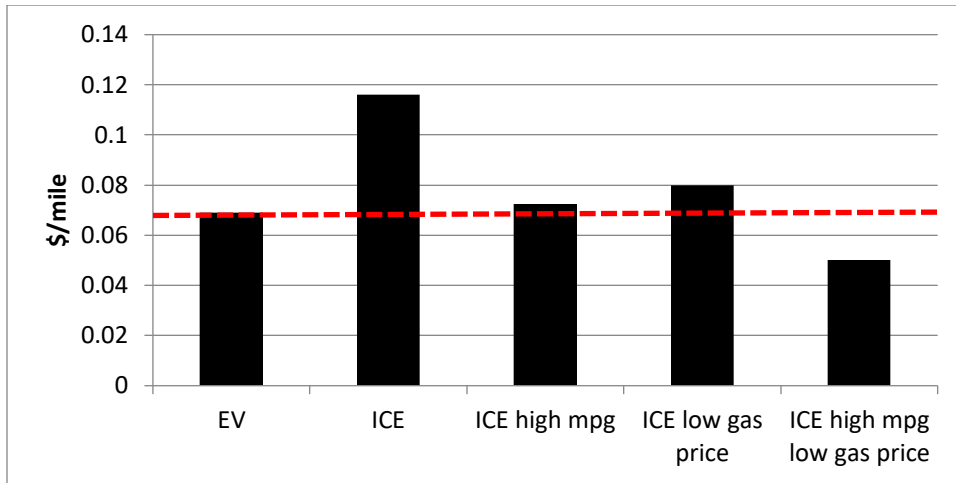
Conclusions and Policy Recommendations

The primary conclusion of the analysis of application 1 is that the average residential customer, as defined in this analysis, achieves a lower fuel cost by choosing an EV. The lower fuel cost is achieved by selecting the TOU rate structure and charging the EV primarily in the super off-peak period. The discussion of application 1 illustrates the complexity required to accurately model an electric utility rate schedule when calculating the cost of EV charging. Accurately modeling rate schedules highlights the shortcomings of information that relies on average rate statistics to describe the cost of EV charging. The analysis included in application 1 also highlights the important variation policy makers and consumers must account for in order to make optimal decisions. The single most important source of variation that will affect the outcome of the model in this application is the distribution of the residential customers load (i.e., household and EV). For instance, the higher the correlation between the customer's original household load and the peak rate periods, the higher the cost of EV charging becomes if the customer switches. Furthermore, the greatest opportunity for residential consumers to minimize the cost of EV charging is to switch to TOU rates, charge their EV off peak and shift household load away from the peak.

Application 2: Direct Current Fast Charging

Direct current fast charging (DCFC) presents perhaps the most novel electric load associated with transportation electrification. DCFC loads are high kW demands that are short lived. DCFC represents convenience for the EV user and simulates gasoline refueling more closely than other charging methods. Also, DCFC has unknown cost implications for the electric distribution system. The need to size distribution system equipment for the peak kW demand makes analysis of the cost of EV charging important for regulators and policy makers. These distribution system impacts are not the subject of this analysis, but should be considered when weighing the benefits of

lowering DCFC bills. The potential reduction in DCFC bills is the subject of the analsyis for application 2.

Currently, DCFC in the SCE service territory falls into the general service (GS) 2 rate category. That category includes the standard GS 2 TOU rate and the TOU EV 4 rate, the latter is available exclusively to electric vehicle loads. This analysis will present the bills associated with a hypothetical DCFC service provider taking service under the SCE TOU EV 4 rate and the TOU EV 7 rate SCE proposed in its January 2017 SB 350 transportation electrification application. Following the bill calculations is a discussion of regulatory principles associated with approving new rate schedules and challenges associated with applying these principles to these novel loads.

The Direct Current Fast Charge Load

The DCFC load profile used in this analysis is reverse engineered from the best publically available data, the Idaho National Laboratory EV Project Electric Vehicle Charging Infrastructure Report.[27] The EV Project installed publically accessible 100 DCFCs across a number of US metropolitan areas, including San Francisco. The Infrastructure Report provides aggregate load profiles for the DCFC and supplemental reports provide additional data and information about the load characteristics measured at DCFC locations. In order to produce a load profile which can be used with the utility system billing model, information from the aggregate load profile and supplemental reports where combined to produce a 96 15 minute intervals per day by 366 day load profile. The nature of DCFC dictates the use of 96 periods rather than 24 periods per day, because the average DCFC observed in San Francisco in the EV Project lasted 22 minutes.[28] The 96 periods per day allow the specification of loads to be based on 15 minute intervals, rather than hourly intervals. The total load for the hypothetical DCFC customer is 22,620 kWh. An example of a three weekday period of the DCFC load profile used in this analysis is shown graphically in Figure 11.

Figure 11: Three Day DCFC Load Profile

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[27] The Infrastructure Report and additional research concerning the EV Project can be found at https://avt.inl.gov/project-type/ev-project

[28] 2016 EV Project Electric Vehicle Charging Infrastructure Report page 46.
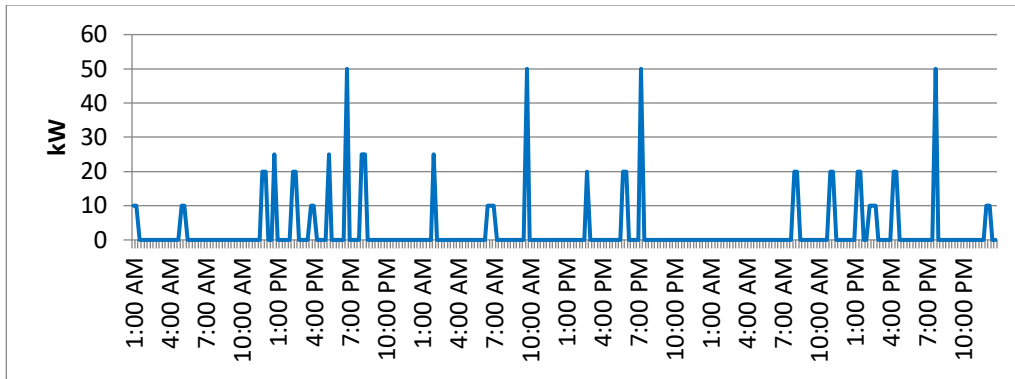
Figure 11 shows how the DCFC load is characterized by short lived high kW loads surrounded by periods of zero load. This characteristic is novel to the DCFC EV load and represents a potential challenge for distribution system operations and maintenance. The result of averaging these short lived intermittent DCFC loads over the entire time period yields the aggregate average load profile shown in Figure 12. This average load profile matches the best available data from the EV Project.

Figure 12: Average DCFC Load Profile
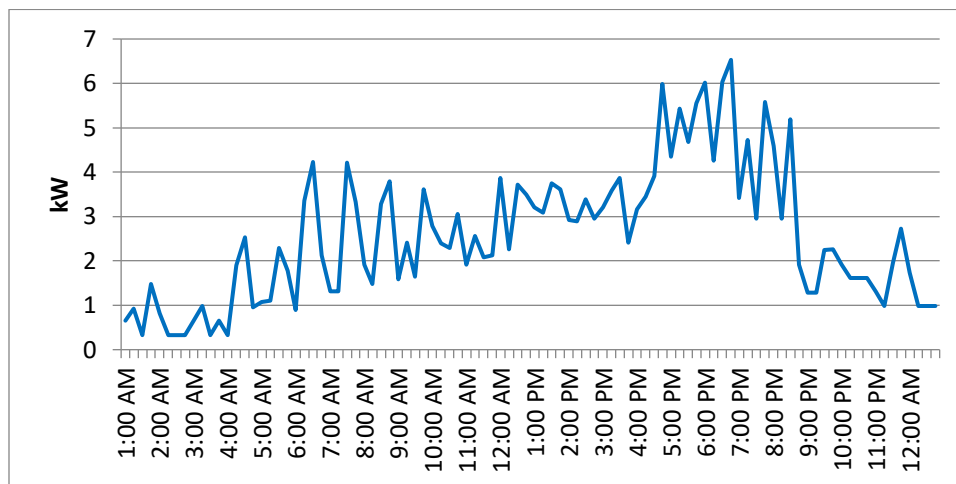
Rates Schedules for Direct Current Fast Charging

General service rate schedules, those applicable to commercial and industrial customers, are defined by kW demand levels. The rate applicable to a specific customer is determined by that customer's maximum monthly kW demand. The basic general service customer classes are defined as less than 20 kW, between 20 and 200 kW, between 200 and 500 kW and greater than 500 kW. The DCFC application generally has a maximum demand of 50 kW. This would place the DCFC customer in the second customer class, between 20 and 200 kW. This classification is not only important in determining the rate schedules applicable to DCFC customers, but also in the regulatory review of the proposed rate schedule. The SCE tariff currently includes two rates available to DCFC customers, GS 2 and TOU EV 4. GS 2 TOU is the default general service rate for all customers with maximum monthly demand between 20 and 200 kW. This rate is applicable to

a wide range of commercial and small industrial customers. TOU EV 4 applies to customers with maximum demand between the same 20 to 200 kW range, but is exclusively applicable to separately metered EV loads. The SCE SB 350 TE application currently before the CPUC includes a proposed TOU EV 7 rate schedule that would similarly be exclusive to EV loads with maximum demand between 20 and 200 kW.

The primary difference between the current TOU EV 4 and proposed TOU EV 7 rate is the the demand charge associated with the current rate. Demand charges impose a cost on the customer for the maximum kW usage during the month. The total demand charge is calculated by multiplying the maximum demand measured during the month by a dollar per kW rate. The maximum kW demand exhibited by a consumer at any time during the month, more so than the total kWh consumed over the month, dictates the distribution system infrastructure needed to serve the customer. Therefore, maximum kW demand is the primary driver of distribution system cost.

Current DCFC Rate Schedule

The current TOU EV 4 rate schedule has a similar structure to the TOU rate discussed in application 1. The fundamental difference is that the TOU EV 4 rate includes a demand charge, dollar per kW, in addition to the energy charges, dollar per kWh. The TOU EV 4 rate includes three TOU periods, off-peak, mid-peak and on-peak. The specific time periods are defined by the same hours in both the summer and winter season. The off-peak period begins at 11:00 pm and ends at 8:00 am every day of the year. The mid-peak period begins at 8:00 am and ends at 12:00 pm and resumes at 6:00 pm and ends again at 11:00 pm every day all year. The on-peak period begins at 12:00 pm and ends at 6:00 pm all weekdays and non-holidays. The remaining hours, 12:00 pm to 6:00 pm on weekends and holidays, are defined as off-peak hours. The TOU rates that apply to those TOU periods vary across the summer and winter months. In summer months the off-peak, mid-peak and on-peak rates are $0.06087/kWh, $0.09211/kWh and $0.25174/kWh respectively. In the winter months, the off-peak, mid-peak and on-peak rates are $0.06551/kWh, $0.07579/kWh and $0.08444/kWh respectively. In addition to these energy charges, the TOU EV 4 demand charge is $15.48/kW.[29] The TOU dollar per kWh portion of the TOU EV 4 rate is shown graphically in Figure 12.

Figure 13: Current TOU EV 4 Energy Charge

[29] The demand charge in dollars is the result of $/kw × max(kW).
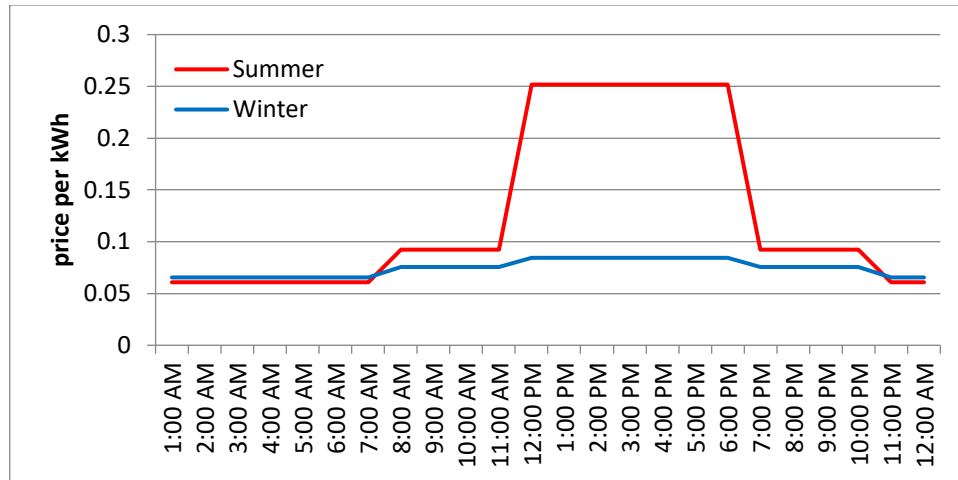
Proposed DCFC Rate Schedule

In response to protest voiced by DCFC and other high kW EV load customers during the public policy process, SCE has proposed to revise its current TOU EV 4 rate. The proposed TOU EV 7 increases the average of the dollar per kWh energy charges, removes the demand charge entirely for a period of time, before subsequently reintroducing a demand charge at levels lower than the current charge. The analysis here considers the initial phase of the TOU EV 7 rate proposal, no demand charge. In addition to removing the demand charge, TOU EV 7 alters the TOU periods in a meaningful way to reflect the changing structure of generation costs resulting in large part due to the increased solar power production.

The TOU EV 7 rate includes four TOU periods, super off-peak, off-peak, mid-peak and on-peak. The summer only includes off-peak and on-peak periods and the winter only includes super off-peak, off-peak and mid-peak periods. The winter off-peak period season begins at 8:00 pm and ends at 7:00 am. The winter super-off peak period begins at 7:00 am and ends at 3:00 pm. This super-off peak period coincides with periods of solar power production and low winter electrical load. The winter mid-peak period begins at 3:00 pm and ends at 8:00 pm. The summer off-peak period begins at 8:00 pm and ends at 3:00 pm. The summer on-peak period begins at 3:00 pm and ends at 8:00 pm. Regardless of season, the price per kWh charges for the super off-peak, off-peak, mid-peak and on-peak are $0.08/kWh, $0.13/kWh, $0.26/kWh and $0.37/kWh respectively. The energy charges for proposed rate TOU EV 7 are shown graphically in Figure 14.

Figure 14: Proposed TOU EV 7 Energy Charge
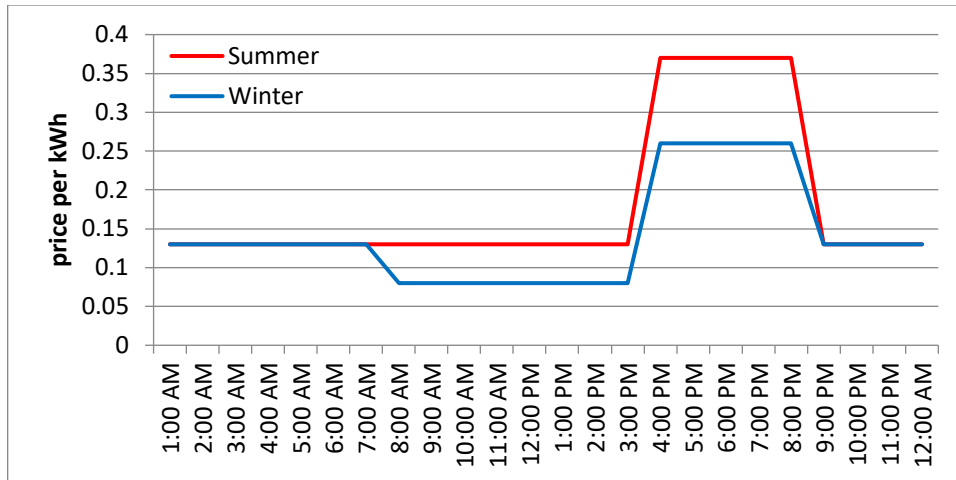
Analysis and Results

The analysis in application 2 is motivated by SCE's proposed TOU EV 7 rate schedule. Customers taking service in the general service classes have expressed the opinion that demand charges make the decision to adopt and charge EVs difficult to justify. Those opinions prompted the SCE proposal of TOU EV 7 which eliminates demand charges initially and phases reduced demand charges in over time. The first part of the analysis of application 2 leverages the utility billing system model to make a simple and direct comparison of the annual bill charged to the hypothetical DCFC customer described above. The second part of the analysis looks at a few of the principles the CPUC uses to determine the appropriateness of rate proposals.

DCFC Bill Calculation Comparison

The primary result of the DCFC bill calculations is the significant reduction in cost to the hypothetical DCFC customer which would result if TOU EV 4 was replaced by TOU EV 7. The DCFC customer would pay an annual bill of $11,540 when taking service under TOU EV 4 and only $4,051 when taking service under TOU EV 7. The institution of the proposed TOU EV 7 rate would reduce the DCFC customer's annual bill of $7,489. This reduction represents a 65% reduction in the cost of DCFC. The comparison of monthly bills paid by the DCFC customer under the two rate schedules is shown graphically in Figure 15.

Figure 15: Monthly DCFC Bills
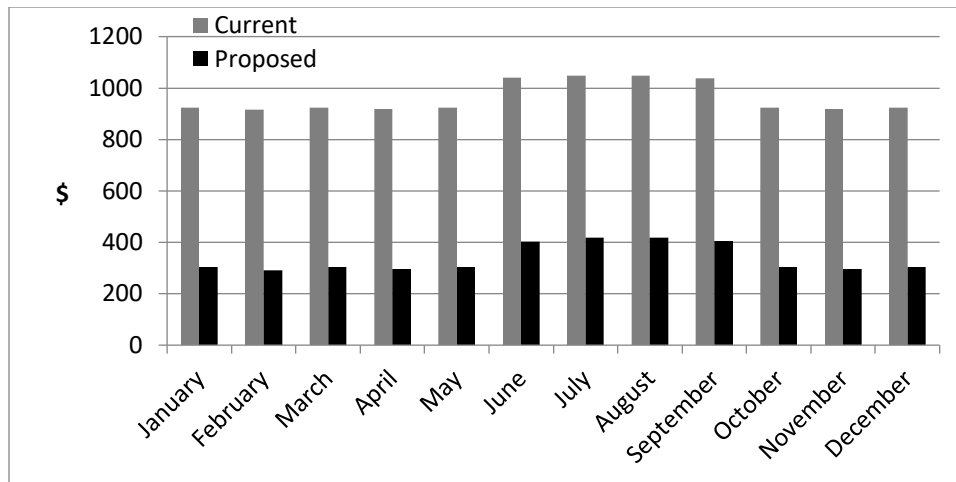
The primary conclusion of this result is that the SCE proposed rate provides significant bill reductions for the DCFC customers who expressed concern about fuel cost incentives of general service EV adoption through the elimination of the demand charge. The result clearly addresses the concerns raised by this specific group of utility customers, and subsequently raises the question of the appropriateness of the rate from the regulator's perspective.

Regulatory Perspective of Proposed Rates

The regulatory process of establishing rates is usually not the foremost interest of the general public and the details may be obscure even to knowledgeable policy makers working outside of the CPUC. The CPUC fundamental regulatory process, the rate case, can be simplified into two primary components or steps: 1) revenue requirement and 2) rate design. The CPUC formally designs rates as the second step of the rate case process. In a rate case, the public utility presents the CPUC with accounting books outlining the costs incurred in the provision of electric service. The CPUC audits the accounting of costs and decides on the amount of justifiable costs and therefore recoverable from rate payers (i.e., the customers). That amount is known as the revenue requirement. In the second step of the process, the costs associated with the revenue requirement are allocated to different customer classes based on the cost of serving each class of customer. An allocation based on cost of service reflects the idea of economic efficiency and attempts to allocate the cost of physical assets and general expenses to customer classes based on how those assets are used or why those costs were incurred by the utility in the process of providing electricity.

In the absence of a full cost of service analysis, the CPUC uses guiding principles to judge the reasonableness of a proposed rate. CPUC Resolution E-4831 is a specific example of a recent CPUC decision on the appropriateness of a proposed rate outside of the context of a rate case and cost of service study.[30] The principles outlined in that resolution are consistency with

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[30] Resolution E-4831 at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M182/K436/182436159.PDF

principles of time-varying rates, appropriateness of time-of-use periods, alignment with revenue-neutral rate design, and consistency with other state and CPUC policies.

SCE's proposed TOU EV 7 rate can be reviewed in the context of these principles and doing so should prompt discussion of the reasonableness of the proposal and the principles more generally. First and simplest are the principles of consistency with other policies and consistency with time-varying rates. As discussed in the previous section, the proposed TOU EV 7 rate significantly decreases the annual bill of the hypothetical DCFC customer. The state and, by legislative and executive direction, the CPUC has policies supporting the widespread and rapid electrification of transportation. In light of this, the proposed rate is clearly consistent with the state and CPUC policy agenda. In addition, the rate includes TOU rate periods and rates, and in this simple sense is consistent with the principle of time-varying rates. The other two principles, appropriateness of time-of-use periods and alignment with revenue-neutral rate design, provide an opportunity for meaningful discussion.

In the Resolution cited above, the CPUC discussed the California Independent System Operator's (CAISO) suggested TOU periods, outstanding rate design window and transportation electrification applications, as well as other CPUC actions on the issue. The rate under consideration in that Resolution, which was accepted, included a peak period between 2:00 pm and 8:00 pm for all seasons. The CPUC included a directive to consider whether or not the peak period should be moved to later in the day. This idea that the peak demand period occurs later in the day is also reflected in the CAISO suggested TOU periods. The CAISO suggestion also includes differentiation between the summer and winter season which is consistent, in part, with the TOU EV 7 proposal. The CAISO suggestion however included a mid-peak period in the summer season covering the early afternoon hours that is not included in the SCE proposed TOU EV 7 rate. The Resolution provides additional detail and references and the CAISO open access same time information system provides access to raw data relevant to this evolving matter. The primary driver of the shifting peak periods is not the shifting of load per se, but the shifting of net load, the total load minus non-dispatchable renewable generation.

The alignment with revenue neutral-rate design is another principle which warrants increased attention in light of the SCE TOU EV 7 rate proposal. Revenue-neutral rate design can be principally defined in terms of the simplified two-step process, revenue requirement and rate design. The revenue requirement represents the dollars a utility collects to cover cost and continue reliable operation. Rate design represents how that revenue requirement will be recovered from different classes of customers. Generally, larger customers pay lower rates largely because they take service at higher voltage and therefore require the utility to make less capital investment in equipment needed to transform service voltage than smaller customers and because greater levels consumption allow fixed costs to be spread over a greater number of kWh. However, lower rates should not be misconstrued to be the same thing as lower bills.

The revenue requirement is the starting point of rate design and therefore has one basic but important implication for different customer classes. If one customer class's rates area reduced

in the rate design process, than another customer class's rates must increase to produce the revenue requirement for the utility. Revenue-neutrality reflects a similar notion although it is subtly different. The principle and its subtle difference can be illustrated with the following thought experiment. Consider a utility for which the revenue requirement is already determined. Assume that the utility only has one class of customers, and only one rate schedule, but the utility proposes to add a second rate schedule. Assume also, if the new rate schedule is accepted by the CPUC, than all the customers in the one class would switch to that new rate schedule. In order the proposed rate schedule to be revenue neutral it must generate the same revenue when all the customers switch as the current rate schedule did before any switch.

In the Resolution above, the subject was a proposed TOU EV 6 rate. In order to compute revenue neutrality, the utility and CPUC used the customer class associated with TOU 8 rate. The TOU 8 rate is the default rate schedule for customers with monthly maximum demand greater than 500 kW. This would include industrial processing and manufacturing facilities of all types. The characteristic connecting the two rate schedules is demand greater than 500 kW. However, TOU EV 6 is only available for customers who are exclusively EV charging loads. Therefore, the customers traditionally on TOU 8 would not be able to switch to TOU EV 6. This fact should raise some debate about the appropriateness of making alignment with revenue neutrality a guiding principle in the case on novel loads like DCFC.

In the DCFC case, the GS-2 Demand rate would have traditionally been the otherwise applicable rate for customers who could elect to take service under TOU EV 4 or TOU EV 7, but did not choose too. The GS-2 rate customers have undergone mandatory migration to TOU rates, and several are available to the GS 2 customer class under rate schedule TOU GS 2. The simplest of the TOU GS 2 rates is TOU GS 2 Option A.[31]   For this analysis, TOU GS 2 is assumed to be the otherwise applicable rate for purposes of revenue neutral alignment of TOU EV 7, and the utility billing system model is used to calculate revenue neutrality. In order to approximate the alignment, the bill (utility revenue) of the average GS 2 customer can be calculated under both rate schedules. The average GS 2 utility customer load is available from the SCE public load data similar to the data used in application 1 for residential customers. The calculation absent any other consideration shows that the average GS 2 customer pays more under the TOU EV 7 rate, than the GS 2 TOU Option A rate. The average GS 2 customer's annual bill is $23,489 under TOU EV 7 and $21,321 under TOU GS 2. If the analysis is extended to TOU EV 4, the average GS 2 customer's annual bill is $19,978. The calculation of the average customer bill is not a multiple of the total revenue collected by the utility desired under the revenue neutrality alignment principle given the existence of a demand charge.[32]   However, the average customer calculation is an

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[31] The details of TOU GS 2 Option A can be found along with the other SCE rate schedules under Regulatory Information, SCE Tariff Books at the SCE website.

[32] By definition of the arithmetic average used in this calculation, and the linear nature of the energy calculations, the average customer bill is a scalar multiple of the total revenue collected from all customers for the kWh portion of the bills. The demand portion of the calculation represents a non-linear operation, such that the average maximum is not necessarily a scalar multiple of the sum of all customers' maximums. Intuitively, if the maximums

indication of the revenue neutrality alignment. The result is that the TOU EV 7 rate and GS 2 TOU are not revenue neutral, and the TOU EV 7 rate under these assumptions collects more revenue. However, the average customer calculation with a demand charge necessarily underestimates the total revenue calculation, so the two numbers are, in all likelihood closer together. Assume for the moment that, with more information about all GS 2 customer loads, the two rates are revenue neutral, and that TOU EV 7 aligns with the other rate design principles outlined above. Should TOU EV 7 be approved on that basis?

GS 2 TOU Option A and TOU EV 7 are revenue neutral in the limited sense described above. Only if all GS 2 customers switch to TOU EV 7 will the same revenue be returned to the utility. However, all GS 2 customers are not eligible to take service under TOU EV 7. In addition, the revenue returned to the utility under TOU GS 2 by the DCFC customer and the average GS customer is different, $11,788 and $21,321 respectively. Also, and more importantly, the revenue returned to the utility by the DCFC customer is lower under TOU EV 7 than TOU GS 2, $4,051 versus $11,788. What is interesting is that the revenue from the DCFC customer is similar under TOU GS 2 and EV TOU 4, $11,788 and $11,540, despite the fact that the DCFC customer is has a fundamentally different load profile from the average GS customer. And perhaps this is the more important point. Should revenue neutrality of EV rates be a principle when the customer class used to judge revenue neutrality mostly includes customers who are not electric vehicle customers and are not eligible for the rate they are being used to judge. The concreteness of the difference between DCFC rate customers and GS 2 customers is illustrated in Figure 16.

Figure 16: Average GS 2 and Hypothetical DCFC Customer Daily Load
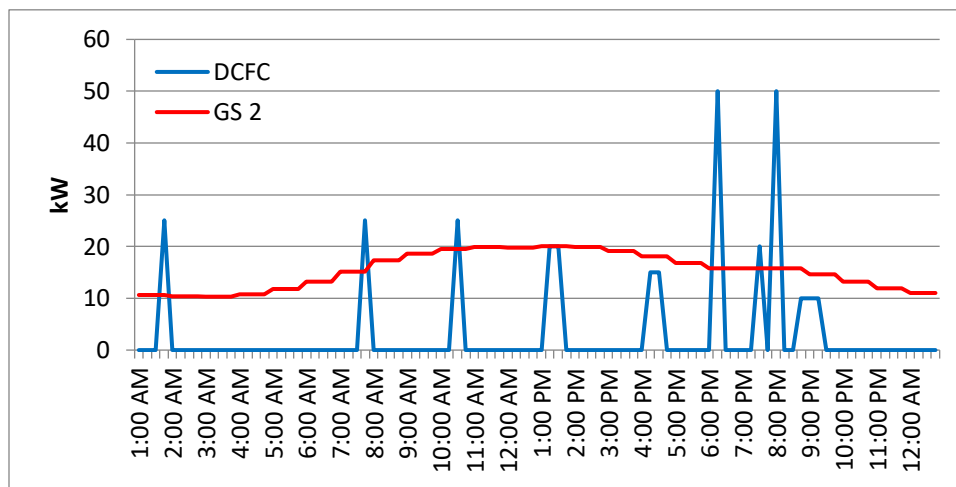
The conceptual difference in the cost of serving the average GS 2 customer and the hypothetical DCFC charging customer can also be understood through Figure 16. As previously discussed, the maximum kW demand exhibited by a customer is the primary driver of the

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of all customers do not happen at the same time, then two calculations of revenue associated with the demand charge will not be equal. In fact the average customer bill multiplied by the number of customers is necessarily less than the total bills collected when a demand charge exists.

capital costs required to serve that customer. The distribution infrastructure necessary to serve the customer must be large enough to support the maximum kW demand. In Figure 16, the maximum kW demand is 50 kW for the hypothetical DCFC customer and approximately 20 kW for the average GS 2 customer. Because the cost of service is determined by the maximum kW demand rates have been designed to collect the cost through a demand charge. If the demand charge is removed then the lost utility revenue needs to be recovered through an increase in the per dollar per kWh energy charge. If the ratio of total kWh annually to maximum kW decreases, then the necessary increase to the dollar per kWh charge increases. Figure 16 illustrates the fact that the average GS customer has a much higher ratio of total kWh to maximum kW, then the hypothetical DCFC customer. This illustration should serve as the setting to discuss the cost implications of DCFC customers and the relevance of using all GS 2 customers to determine the revenue neutrality of TOU EV 7 which most of these customers are not eligible to take.

Conclusion

This report illustrates the complexity associated with making electric utility bill calculations for the basic utility rate schedules and develops a model to automate those calculations for policy analyses. The purpose, in part, is to highlight the information required for the general public to make informed decisions concerning their electricity consumption based on different rate structures that may be available to them. Policy makers are interested in the impact this information will have on consumers decisions, especially when electric power cost influences vehicle purchase (e.g. whether to purchase an electric vehicle or not). Policy makers also guide the direction regulators will take in the development of new rate structures. The utility billings system model used in this report addresses current issues related to two different EV charging applications.

The first application analyzes the bills for a residential customer faced with the choice between a default inclining block and an optional TOU rate. The primary finding is that the average customer who charges their EV in the off peak periods is better off under the TOU rate rather than the tiered rate. The electric bill under the TOU rate implies an electric fuel cost of $0.069/mile compared to a gasoline fuel cost of $0.116/mile. These costs, however, are subject to changes in the fuel prices and the efficiency of vehicles.

The second application analyzes the electric bill of a hypothetical customer supplying DCFC services. The primary finding is the significant, 65%, decrease in DCFC customer bills that results from the revenue neutral proposed rate. The reduction on the DCFC customer bill is the result of the removal of a $15 demand charge from the current EV TOU 4 rate. The discussion which follows the bill calculations asks what role a revenue neutral calculation can or should play in determining the appropriateness of proposed rate schedules.

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Appendix: SCE Baseline Regions