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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Consider Alternative-fueled Vehicle Tariffs, Infrastructure and Policies to Support California's Greenhouse Gas Emissions Reduction Goals.	Rulemaking 09-08-009 (Filed August 20, 2009)

COMPLIANCE FILING OF PACIFIC GAS AND ELECTRIC COMPANY (U 39E), SOUTHERN CALIFORNIA EDISON COMPANY (U 338E) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902M) PURSUANT TO ORDERING PARAGRAPH 7 OF D.11-07-029

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Dated: December 28, 2012

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Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company hereby file their load research report as required by Ordering Paragraph 7 of D.11-07-029.[1/] The load research report and attachment are included as Appendix A to this pleading.

Respectfully Submitted,

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Dated: December 28, 2012

1/ Southern California Edison Company and San Diego Gas & Electric Company have authorized PG&E to file this compliance report on their behalf.

Joint IOU Electric Vehicle Load Research Final Report

Filed on December 28, 2012

Electric Vehicle Load Research & Cost Studies

R.09-08-009

(AFV OIR)

Ordered in D.11-07-029

Pacific Gas and Electric Company®

SOUTHERN CALIFORNIA EDISON®
An EDISON INTERNATIONAL® Company

SDGE
A Sempra Energy utility®

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Executive Summary:

On July 25th, 2011 the California Public Utilities Commission (CPUC) issued D.11-07-029 (the Phase 2 Decision) to evaluate policies and develop infrastructure sufficient to overcome barriers for the deployment and use of Plug-in Electric Vehicles (PEVs) in California. The Decision ordered California's investor owned utilities (IOUs) made up of Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E) and Southern California Edison (SCE), to conduct research to examine PEV customer charging behavior, as well as track any service upgrade costs due to PEV load. The scope was proposed and refined by the IOUs in December of 2011 and was further discussed at a public workshop held at the CPUC on February 16, 2012. As a result of Administrative Law Judge DeAngelis' Ruling on August 21, 2012 addressing the scope, the IOUs filed the revised scoping document detailing how the requirements in D. 11.07.029 would be met.[1] Decision 11.07.029 acknowledged that many uncertainties surround the evolving market for Plug-in Electric Vehicles and charging services[2] and the IOUs believe that is still true 18 months later.

This final report includes data for the period June 2011 through October 2012 and the conclusions reached through analyzing this data. It is important to note that the behavior of the early adopters of PEVs during this time period may not be representative of the average customer. In addition, the charging level of the vehicles during the study period may not necessarily be representative of the PEVs in the market today.

As of October 31, 2012, the IOUs estimate there are over 17,000 new light duty PEVs within the three service territories. Through monitoring service upgrade costs due to new PEV load, the IOUs have determined the costs are currently insignificant. The IOUs have completed more than 6,000 residential infrastructure checks and only 22 upgrades (0.4%) have been identified and completed. In all but 5 instances in the PG&E territory, the existing allowance was sufficient to cover the customer portion on the upgrade.

Based on these results, SCE and SDG&E conclude that existing Rule 15 & Rule 16 allowances applied to all new load additions are also appropriate for their new PEV load. This is consistent with other new load that utility customers may add. The current allowances are sufficient for SCE & SDG&E PEV customers and there is not sufficient evidence that an exception to established policy is necessary. SCE and SDG&E recommend the policy of treating all residential service facility upgrade costs for PEV load in excess of the residential allowance as common facility costs between July 25, 2011 and June 30, 2013[3], as ordered by the CPUC in the Phase 2 Decision, not be extended past June 30, 2013 in their service territories.

While PG&E generally supports uniform treatment of residential load, PG&E recommends that no final ruling be made on PEV allowances at this time. Rather, the current "common facility" exemption should be extended for 3 years so that additional information regarding upgrade costs can be gathered. PG&E

[1] See Advice Letters 2403-E for SDG&E, 2786-E for SCE, and 4115-E for PG&E
[2] D.11.07-029, p 6
[3] D.11-07-029, Ordering Paragraph 5

acknowledges that the PEV customer specific costs to date have been *de minimus*, but believes that it is too early to understand what the potential magnitude of upgrade costs might be given further EV penetration. PG&E believes that this is the prudent course given that the exemption currently creates minimal cost shifts but its elimination could potentially create a barrier for a certain future EV adopters. PG&E suggests that annual EV cost reports be filed at the CPUC for the next 3 years, and at the end of this time the exemption issue can be more thoughtfully addressed. However, should the costs grow substantially prior to the conclusion of three years, PG&E would reserve the right to file a motion in this or an appropriate successor proceeding to have the exemption issue immediately brought to the Commission's attention for consideration[4].

The IOUs tracked Load Research data on a monthly basis and have included 15 months of data in the final analysis. The usage and demand of customers was tracked in each rate group. The goal of this structure was to determine how monthly usage varies, how rates impact peak demand and how usage varies by time of use rate among different groups of customers. A baseline for all residential customers has been included for context in the form of an average for a month during the season being examined.

As a general principle, customers on TOU rates refueled their vehicles during the off-peak periods during the weekdays. Although PEV customers have higher usage and higher demand on the system than non PEV customers, peak times for PEV Demands have typically been in the early morning hours compared to evenings for typical residential customers.

Part 1: Introduction

California is the fifteenth largest emitter of greenhouse gases, representing about 2% of worldwide emissions, and California's transportation sector is the largest contributor, consisting of 38% of the State's total greenhouse gas emissions. Passenger vehicles alone are responsible for almost 30% of California's greenhouse gas emissions.[5] To address these vehicle emissions, the California Air Resources Board proposed a comprehensive three prong strategy, which includes the following: reduce greenhouse gas emissions from vehicles, reduce the carbon content of the fuel vehicles use, and reduce the miles vehicles travel. Electrification of vehicles is a critical component of this strategy.[6]

On July 25th, 2011 the California Public Utilities Commission (CPUC) issued D.11-07-029 (the Phase 2 Decision) to evaluate policies and develop infrastructure sufficient to overcome barriers for the deployment and use of plug-in electric vehicles (PEVs) in California. The decision acknowledged that

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[4] Given the expected higher demand requirements of newer vehicles SCE foresees the potential for some customers requesting service upgrades to support DC fast chargers in residential settings. In SCE's view, the Commission in D.11-07-029 did not intend for ratepayers to subsidize these types of installations.

[5] *Climate Change Scoping Plan, A Framework for Change, Pursuant to AB 32, the California Global Warming Solutions Act of 2006* (herein ARB's 2008 Scoping Plan) at 11, adopted by the California Air Resources Board on December 11, 2008. The ARB 2008 Scoping Plan is available at: http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm.

[6] D.11.07-029, p 3-4

many uncertainties surround the evolving market for Plug-in Electric Vehicles and charging services[7] and that is still true 18 months later.

In mid-2011 when the Phase 2 Decision was issued there were essentially two PEVs widely available in California, the Nissan LEAF and the Chevy Volt. Since that time several new car models have come to market including the Tesla Model S, BMW Active E, the Coda Sedan, Ford Focus, Honda Fit EV, Mitsubishi "I", Toyota Plug-in Prius, and Ford C-Max Energi, and the list keeps growing. One noticeable trend in the newer models of PEVs is a higher charging level. The LEAF and Volt charge at a rate 3.3 kW, while the majority of the new models charge at 6.6 kW and some at nearly 20 kW. The 2013 LEAF has a 6.6 kW on-board charger. The charging level of the vehicle may be one of the more important factors in determining policies around PEVs.

The IOUs have observed a high correlation of PEV customers and solar customers. The percent of PEV owners that are also solar customers range from 21% to 30% for the three IOUs. These customers are generally not interested in separately metered electric vehicle rates. The recognition of this customer preference coupled with the rising number of solar customers in California will be an important consideration in determining the offerings for electric vehicle customers.

This final report includes data for the period June 2011 through October 2012 and the conclusions reached analyzing the data. It is important to note that the behavior of the early adopters of PEVs during this time period may not be representative of the average customer. And, as noted earlier, the charging level of the vehicles during the study period may not be representative of the PEVs in the market today.

Part 2: Scope of Load Research

In D.11-07-029 the CPUC required the IOUs to perform load research to inform future Commission policy[8]. The CPUC determined that additional research is needed to inform policies for the next stages of electric vehicle market development.[9] Specifically, the CPUC ordered the IOUs to:

1. Track and quantify all new load and associated upgrade costs in a manner that allows PEV load and related costs to be broken out and specifically identified. This information shall be collected and stored in an accessible format useful to the Commission.

2. Evaluate how metering arrangements and rate design impact PEV charging behavior.

3. To the extent relevant, determine whether participation in demand response programs impacts PEV charging behavior.

[7] D.11.07-029, p 6
[8] D.11-07-029, p. 3
[9] D.11-07-029, p. 60

4. Determine how charging arrangements, including metering options and alternative rate schedules impact charging behavior at Multi Dwelling Units (MDU).

5. Evaluate whether distribution costs are increased by different charging levels, i.e., Level 1, Level 2, and quick charging, in public locations.

6. Separately track costs associated with PEV-related residential service facility upgrade costs and treated as "common facility costs" between the effective date of this decision and June 30, 2013, and propose a policy and procedural mechanism to address these residential upgrade costs going forward.[10]

In collaboration with the Energy Division and other stakeholders, the IOUs developed a load research plan to meet these specific requirements and filed the plan with the CPUC on October 1, 2012.[11] Areas where data may not be available or sufficient to produce data or conclusions were noted. The CPUC further ordered the IOUs to complete the load research by January 1, 2013 and file a load research report by January 1, 2013.[12] The scope was proposed and refined by the IOUs in December of 2011 and was further discussed at a public workshop held at the CPUC on February 16, 2012. As a result of Administrative Law Judge DeAngelis' Ruling on August 21, 2013 addressing the scope, the IOUs filed the revised scoping document detailing how the requirements in D. 11.07.029 would be met.[13] In addition to the results of the load research ordered by the CPUC in D.11-07-029, the IOUs have included the results of other relevant studies performed during the same timeframe, such as the First Year Evaluation for San Diego Gas & Electric's Electric Vehicle Pilot issued December 2012.[14] The sum of these data provides a starting point to inform future Commission policy.

Items 1, 5 and 6 are addressed in Part 3 covering Cost Tracking and items 2, 3 and 4 are addressed in Part 4 covering Load Research data.

Part 3: Cost Tracking Data, Findings, and Policy Recommendations

Introduction

In D.11-07-029 the CPUC ordered:

- Between July 25, 2011 and June 30, 2013, all residential service facility upgrade costs in excess of the residential allowance shall be treated as common facility costs rather than being paid for by the individual plug-in hybrid and electric vehicle customer.[15]

[10] D.11-07-029, Ordering Paragraph 6
[11] See Advice Letters 2403-E for SDG&E, 2786-E for SCE, and 4115-E for PG&E
[12] D.11-07-029, Ordering Paragraph 7
[13] See Advice Letters 2403-E for SDG&E, 2786-E for SCE, and 4115-E for PG&E
[14] See Appendix A of this report for the complete study.
[15] D.11-07-029, Ordering Paragraph 5

- The CPUC further order the IOUS to separately track costs associated with PEV-related residential service facility upgrade costs and treated as "common facility costs" and propose a policy and procedural mechanism to address these residential upgrade costs going forward. [16]
- The IOUs should evaluate whether distribution costs are increased by different charging levels, i.e., Level 1, Level 2, and quick charging, in public locations. [17]

Approach

Based on confirmed notification of PEV load from one of several sources such as the customer or auto OEMs, the utilities' service planning departments conduct field assessments, which include inspecting the local utility electrical infrastructure to ensure the additional PEV load can be supported by the existing electrical system. If it is discovered that previously existing loads have brought the existing electrical infrastructure to the point where it cannot support additional PEV load, and an upgrade/reinforcement of the existing system is required, the utility representative prepares the appropriate paperwork and the additional Rule 15/16 costs in excess of the allowance are treated according to the Phase 2 Decision.

The IOUs have created PEV-specific work orders to capture the costs. These work orders are used when previously added loads have brought the electrical infrastructure to the point where additional PEV load would cause it to be overloaded. In other words, if the customer adds other loads such as air conditioners, washers, dryers, and pool pumps, the upgrade costs will be treated as normal under Rules 15/16. This is due to the IOUs' inability to disaggregate load and assign costs by appliance.

"Upgrade costs" are defined as all costs (distribution, service, common facility material and labor, overheads, etc.) resulting from upgrades and reinforcements to existing facilities associated with the addition of PEV load. As IOUs cannot reasonably disaggregate load for the purposes of attributing costs to a specific technology or appliance, it is necessary to apply a set of counting rules:

1. Upgrade Required – New PEV Load – When the utilities are made aware of new PEV load and a load assessment does not identify any other material sources of new load to be contributing to an upgrade to support additional PEV load, all costs will be allocated to the PEV. Alternatively, if the utilities identify new PEV load but determine that an upgrade was necessary even prior to the addition of the PEV load, no costs will be attributed to the PEV load.

2. Upgrade Required – Multiple Sources of New Load – Due to the utilities' inability to disaggregate load and accurately attribute costs, no upgrade cost will be attributed to PEV loads when multiple sources of new load are identified.

3. No Upgrade Required – New PEV Load – When there has been an addition of PEV load but no immediate upgrade is necessary, no costs will be attributed to the PEV.[18]

[16] D.11-07-029, Ordering Paragraph 6
[17] D.11-07-029, Ordering Paragraph 6
[18] While the addition of the PEV load may not immediately require an upgrade, it may bring the system materially closer to needing an upgrade, resulting in costs at some point in the future. No upgrade costs will be allocated to the PEV in this circumstance.

The utilities acknowledge that using this set of rules may understate or overstate costs related to PEVs, but these rules have been developed to be transparent and operationally practical. The IOUs have determined that this method is currently the most practical way to capture costs attributable to PEVs. The IOUs believe that currently available alternative methods inappropriately bias the costs related to PEVs.

Finally, the IOUs are reporting the actuals costs, as recorded in each of their financial systems, when the work orders have been completed and finalized.

Data - By IOU:

Table IOU-1 provides a summary of all the PEV-related residential service facility upgrade costs, as recorded by each of the three IOUs.

Table IOU-1: Summary of Cost Tracking Data

	PG&E	SCE	SDG&E
Estimated PEV customers through October 31, 2012	6,969	7,976	2,125
Residential			
Number of Infrastructure Checks completed	3,066	2,600	640
PEV customers requiring service facility upgrades – Rule 15 & 16	9	8	5
Total Costs Incurred	$41,834	$28,097	$9,592
Range of Costs	$656-$8,265	$274 - $10,384	$666 - $4,007
Average Cost	$4,648	$3,512	$1,590
Number of Foregone Rule 16 Billings	5	0	0
Existing Residential Allowance	$1,918[19]	$2,506[20]	$2,578[21]
Amount of Foregone Billings – Rule 16	$9,226	$0	$0
Commercial			
PEV customers requiring service facility upgrades – Rule 15 & 16	0	3	1
Total Costs Incurred	$0	$33,423	$4,007
Range of Costs	N/A	$3,506-$15,977	N/A
Average Cost	N/A	$11,141	N/A

PG&E Specific Details

As of October 2012, PG&E's best estimate of the number of PEVs in the PG&E service territory is 6,969. The data sources for this estimate are customer self-identification, OEM opt-in notification,

[19] PG&E Electric Rule 15, Section C: http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_15.pdf
[20] SCE Electric Rule 15, Section C.3: http://www.sce.com/NR/sc3/tm2/pdf/Rule15.pdf
[21] SDG&E Electric Rule 15, Section C.3: http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-RULES_ERULE15.pdf

identification through city/county permits, and estimates based on national sales. There is a significant amount of uncertainty in this number and it is appropriately considered to be a lower bound of the number of PEVs in the territory. Since December 31, 2010, PG&E's estimate of PEVs in the service territory has grown by 6,894 vehicles.

While PG&E's total estimate of PEVs in the service territory is 6,969, PG&E is only able to perform service assessments for those vehicles for which customer specific notification is received. As of October 31, 2012, PG&E had completed 3,066 such service assessments. Of the 3,066 service assessments completed to date, 9, or 0.3%, have required upgrades due solely to the addition of PEV load. In 5 instances the allowances were not sufficient to cover the customer portion of the upgrade and the customer would have incurred costs had the exemption not been in place. The total cost of the excess over the allowance for all 5 customers combined was $9,226.

SCE Specific Details

As of October 2012, SCE's best estimate of the number of PEVs in the SCE service territory is 7,976. The data sources for this estimate are: Customer self-identification, OEM-shared data (with customer consent), city/county electrical permits, estimates based on national sales, and PEV counts received through a third party DMV vendor. There is some amount of uncertainty in this number and it is appropriately considered to be a lower bound of the number of PEVs in the territory. Since December 31, 2010, SCE's estimate of PEVs in the service territory has grown by 6,962 vehicles or roughly by a factor of 6.9.

SCE is only able to perform a service assessment when it has been notified of the street address of a charging location. As a result, as of October 31, 2012, SCE had completed approximately 2,600 such service assessments out of the 6,969 electric vehicles estimated in its service territory. Of the 2,600 service assessments completed to date, 8, or 0.3%, have required upgrades due solely to the addition of PEV load.

SCE also had three upgrades relating to the commercial installation of DC Fast Chargers totaling approximately $33,000.

SDG&E Specific Details

As of October 2012, SDG&E's best estimate of the number of PEVs in the SDG&E service territory is 2,125. The data sources for this estimate are: customer self-identification, OEM opt-in notification, car dealership reporting, and identification through city/county permits. There is some uncertainty in this number and it is appropriately considered to be a lower bound of the number of PEVs in the SDG&E service territory. Since December 31, 2010, SDG&E's estimate of PEVs in the service territory has grown by just over 2,000 vehicles.

While SDG&E's total estimate of PEVs in the service territory is 2,125, SDG&E is only able to perform service assessments for those vehicles for which notification is received via: customer self-identification or and identification through city/county permits. As of October 31, 2012, SDG&E had completed approximately 640 such service assessments. Of the approximately 2,125 vehicles in SDG&E's service territory, 5, or 0.2%, have required upgrades due solely to the addition of PEV load.

For public charging installed in San Diego under the EV Project[22], SDG&E has completed 1 commercial upgrade at a site that will host multiple charging units. As of October 31, 2012, 323 public chargers in 97 locations were installed in San Diego under the EV project.

Conclusions/Recommendations

As each of the IOUs have described, the occurrence of upgrades due to the addition of new PEV load is currently insignificant. The IOUs have completed more than 6,300 residential infrastructure checks and only 22 upgrades (0.3%) have been identified and completed. In all but 5 instances, the existing allowance for residential upgrades was sufficient to cover the customer portion on the upgrade.

Based on these results, the SCE and SDG&E conclude that existing Rule 15 & Rule 16 allowances applied to all new load additions are also appropriate for new PEV load in their service territories. This is consistent with other new load that utility customers may add. The current allowances have demonstrated they are sufficient for PEV customers and there is not sufficient evidence that an exception to established rate making policy is necessary.

SCE and SDG&E recommend the policy of treating all residential service facility upgrade costs for PEV load in excess of the residential allowance as common facility costs between July 25, 2011 and June 30, 2013[23], as ordered by the CPUC in the Phase 2 Decision, not be extended past June 30, 2013 in their service territories. Since the current allowances for residential upgrades for SCE and SDG&E are sufficient to cover upgrades related to PEVs, the tracking and reporting requirements related to the PEV "common facility" exemption create an unnecessary regulatory burden. The outcome from the customer perspective is the same with or without the exemption; no additional out of pocket expense.

While PG&E generally supports uniform treatment of residential load, PG&E recommends that no final ruling be made on PEV allowances at this time. Rather, the current "common facility" exemption should be extended for 3 years so that additional information regarding upgrade costs can be gathered. PG&E acknowledges that the PEV customer specific costs to date have been *de minimus*, but believes that it is too early to understand what the potential magnitude of upgrade costs might be given further EV penetration. PG&E believes that this is the prudent course given that the exemption currently creates minimal cost shifts but its elimination could potentially create a barrier for a certain future EV adopters. PG&E suggests that annual EV cost reports be filed at the CPUC for the next 3 years, and at the end of this time the exemption issue can be more thoughtfully addressed. However, should the costs grow substantially prior to the conclusion of three years, PG&E would reserve the right to file a

[22] On August 5, 2009, ECOtality was awarded a $99.8 million dollar grant from the U.S. Department of Energy to embark on the PEV Project deploying chargers in major cities and metropolitan areas across the United States. The Project was officially launched on October 1, 2009. In June 2010, the Project was granted an additional $15 million by the U.S. Department of Energy. With partner matches, the total value of the Project is now approximately $230 million.

[23] D.11-07-029, Ordering Paragraph 5

motion in this or an appropriate successor proceeding to have the exemption issue immediately brought to the Commission's attention for consideration[24].

For non-residential upgrades resulting from level 1, level 2 and quick charging, in public locations, SCE completed 3 commercial upgrades and SDG&E completed 1 residential upgrade through October 31, 2012. This data is insufficient to draw any conclusions regarding commercial upgrades for PEV charging in public locations.

Part 4: Load Research & Customer Behavior on Rates in Various Settings

Introduction

In D.11-07-029 the CPUC ordered the IOUs to:

- Evaluate how metering arrangements and rate design impact PEV charging behavior.[25]
- To the extent relevant, determine whether participation in demand response programs impacts PEV charging behavior.[26]
- Determine how charging arrangements, including metering options and alternative rate schedules impact charging behavior at MDU.[27]

To satisfy these 3 load research requirements, metering data was collected to provide insight into residential charging behavior under:

- Whole House TOU Rates
- Separately Metered TOU Rates
- Tiered Domestics Rates

This metering data provided the basis for analysis as to how charging behavior has been impacted by tariff rates or charging levels. Additionally, the recorded metrics allowed for the evaluation of metering scenarios on PEV charging behavior for customers in the following residential settings[28]:

- Single Family Home
- Multi Family Home
- Net Energy Metering (NEM) or Solar
- Demand Response (DR)

[24] Given the expected higher demand requirements of newer vehicles SCE foresees the potential for some customers requesting service upgrades to support DC fast chargers in residential settings. In SCE's view, the Commission in D.11-07-029 did not intend for ratepayers to subsidize these types of installations.
[25] D.11-07-029, Ordering Paragraph 2
[26] D.11-07-029, Ordering Paragraph 3
[27] D.11-07-029, Ordering Paragraph 4
[28] The categories are not mutually exclusive. For example, a NEM customer that is also on DR would appear in both categories.

The IOUs tracked Load Research data on a monthly basis and have reported 15 months of data in this final report. The usage and demand of customers was tracked in each rate group. The goal of this structure was to determine how monthly usage varies, how rates impact peak demand and how usage varies by time of use rate among different groups of customers. A baseline for residential customers has been analyzed for context in the form of an average for a month during the season being examined.

The analysis includes customers who have a minimum of one month of data during the reporting period. The IOUs determined the minimum number of customers to produce useful information is 15. Metrics with less than 15 customers are clearly noted and not reported due to the 15/15 Rule adopted by Decision 97-10-031.

All statistics in this Load Research report are provided as an average on a per-customer basis in each rate group and are based on interval data collected by each IOU.

All time periods are reported in clock time, except for SCE's load profiles, which are reported in Pacific Standard Time.

PG&E

Whole House (E-9A) and Separately Metered (E-9B) PEV Rates

As of the date of this report, PG&E has two PEV Rates, E-9A and E-9B, for whole house and separately metered PEVs respectively. The experimental E-9A rate is designed for residential customers who have their typical household load and electric vehicle charging on the same meter. The experimental E-9B rate is designed for customers who wish to bill their vehicle charging separately and who have installed a separate meter to do so. Both rate plans use a tiered structure similar in some ways to the standard residential rate. They offer peak, partial-peak, and off-peak energy prices according to the time periods in Table PG&E-1.

Table PG&E-1: E9A and E9B Time Periods

Summer (Service from May 1 through October 31):	
Peak	2:00 p.m. to 9:00 p.m. Monday through Friday.
Partial-Peak	7:00 a.m. to 2:00 p.m. AND 9:00 p.m. to 12:00 midnight Monday through Friday, plus 5:00 p.m. to 9:00 p.m. Saturday and Sunday.
Off-Peak	All other hours.
Winter (Service from November 1 through April 30):	
Peak	N/A
Partial-Peak	7:00 a.m. to 12:00 midnight Monday through Friday and 5:00 p.m. to 9:00 p.m. Saturday and Sunday.
Off-Peak	All other hours.

Each TOU rate has four tiers. Under a tiered rate plan, the cost per kilowatt hour increases as more electricity is used in a billing period. These rates also change seasonally, rising in summer and dropping in winter.

For the purposes of this report, "Group" represents all customers on either the E9A or E9B rate. "Single" represents all single-family E9A or E9B customers. "Multi" represents all multi-family E9A or E9B customers. Single and Multi are mutually exclusive categories that together total to the full population on the rate. There is another category that is very important to carefully consider, Net Energy Metering ("NEM") customers[29]. Anywhere from 20 to27% of PG&E's customers who were on a PEV rate were also on NEM at any given time during this study. Virtually all of these dual PEV Rate/NEM customers were on the single metered E-9A rate (see tables PG&E – 2 and PG&E-3). This dual participation is important to consider because NEM customers' usage statistics are highly influenced by their onsite generation, thereby complicating efforts to isolate the effect PEV ownership has on usage patterns[30].

Table PG&E – 2: NEM Customers on E-9A

Month	Total NEM Customers	NEM as a % of Group	NEM as a % of SF	NEM as a % of MDU
Jun-11	100	27%	28%	13%
Jul-11	111	24%	25%	12%
Aug-11	128	24%	24%	14%
Sep-11	147	24%	25%	13%
Oct-11	152	22%	23%	11%
Nov-11	163	21%	22%	9%
Dec-11	178	21%	22%	11%
Jan-12	190	22%	23%	12%
Feb-12	202	21%	22%	10%
Mar-12	208	20%	21%	10%
Apr-12	229	22%	22%	9%
May-12	242	21%	22%	9%
Jun-12	263	22%	23%	9%
Jul-12	267	21%	22%	8%
Aug-12	286	21%	22%	10%

[29] During the study period, there were fewer than 15 demand response customers who were on E-9A or E-9B.
[30] While there are numerous other demographic and behavioral attributes of this early PEV adopter group that affect usage, there was insufficient data or resources to isolate and identify their contribution to load shapes.

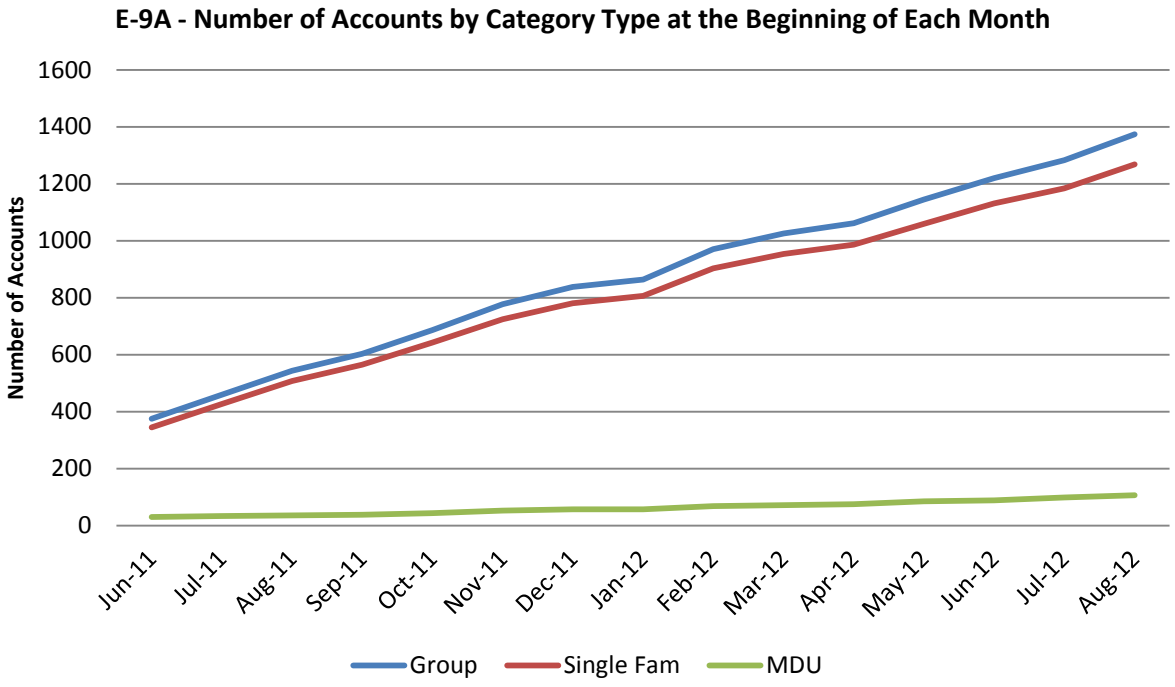
Table PG&E – 3: NEM Customers on E-9B

Month	Total NEM Customers	NEM as a % of Group	NEM as a % of SF	NEM as a % of MDU
Jun-11	0	0%	0%	0%
Jul-11	0	0%	0%	0%
Aug-11	0	0%	0%	0%
Sep-11	2	3%	4%	3%
Oct-11	2	3%	4%	2%
Nov-11	2	3%	4%	2%
Dec-11	2	2%	3%	2%
Jan-12	2	3%	4%	2%
Feb-12	2	3%	4%	2%
Mar-12	2	3%	4%	2%
Apr-12	2	3%	4%	2%
May-12	2	3%	3%	2%
Jun-12	2	2%	3%	1%
Jul-12	2	2%	3%	1%
Aug-12	2	2%	3%	1%

Growth of Electric Vehicle Rates

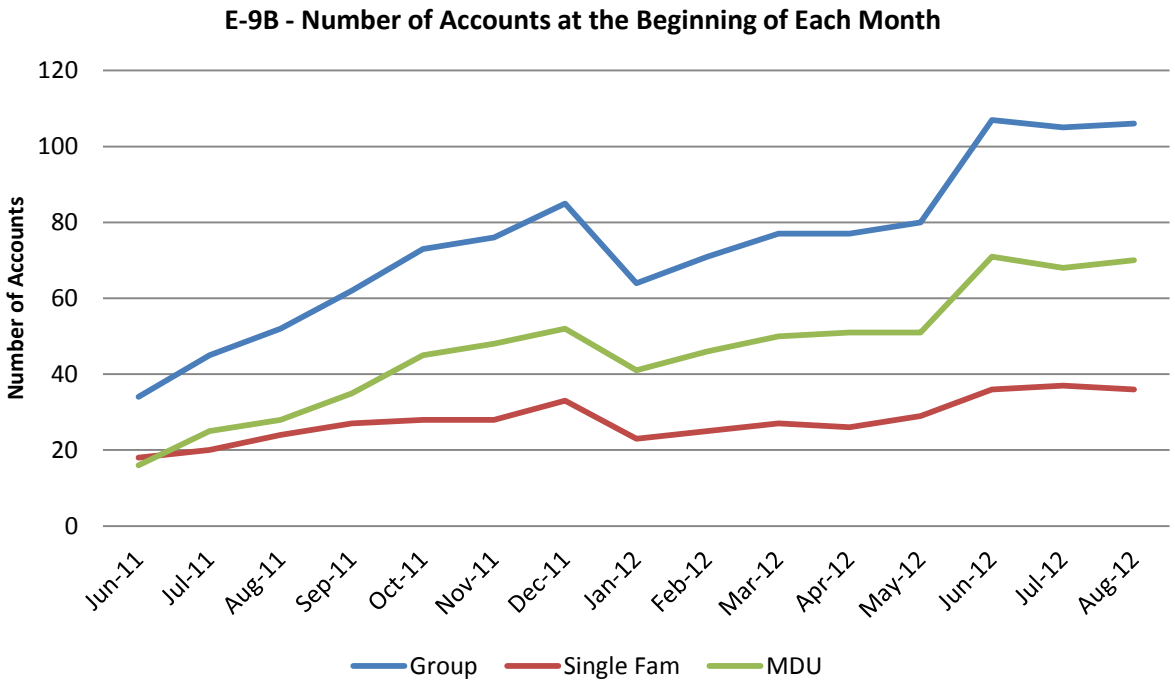
Participation in both E-9A and E-9B has increased several fold during the study period, although the majority of PEV customers have not yet adopted PEV rates. The vast majority of PEV rate participants are on the E-9A whole house rate. Chart PG&E - 1 below shows the total customers on the E-9A rate. During the study period, there was a steady increase in E-9A overall, as well as the Single Family and MDU subcategories. Between June 2011 and August 2012, the number of accounts in the E-9A group as a whole increased by more than 250% at the last reported month compared to the base month.

Chart PG&E – 1: E-9A Customers



The E-9B rate also saw steady growth, albeit from just 34 customers to 106 customers. This can be seen in Chart PG&E – 2.

Chart PG&E – 2: E-9B Customers



Notes of Caution Regarding Reliance upon Load Research Data

The reader should take careful note of the following issues that make the load research data ill-suited for drawing conclusions for policymaking at this time.

1. The current group of PEV owners is comprised of early adopters who are likely to be materially different than later PEV owners. These differences could include, but are not limited to, income, pre-PEV ownership usage habits, NEM penetration, altruistic tendencies and willingness to adopt usage patterns beneficial to grid stability.
2. The types of PEVs available in the market changed significantly during the study period, suggesting that the types of PEVs owned by PEV rate customers would have changed during that same time frame. New vehicles and charging requirements will likely lead to changing charging profiles in the future (i.e. differing charging demands and durations).
3. The study period was relatively short and the customer counts were fairly small in all cases. This is particularly true for E-9B data derived from PG&E's load research sample.
4. The mix of customers being evaluated changed over time due to customers joining or leaving the E9-A or E-9B.

Therefore, while the data collected is illustrative of the behaviors of early adopters of the types of vehicles that are currently available in the market, one cannot conclude that these behavior patterns will hold as PEV technology matures, as charging requirements evolve, and as PEVs achieve greater market penetration thereby reaching different types of customers. Data that is sufficiently reliable for policymaking can only be obtained via an appropriately funded and carefully designed study that controls for the above issues.

Average Monthly Usage for PEV Rate Customers Compared to the Full Residential Population

Keeping in mind the above cautions about the data collected, the average monthly usage of the current crop of E-9A and E-9B customers was compared to the average usage for PG&E's entire residential population. The charts below show the average monthly usage for each E-9A category and the average monthly usage for the full residential population. The data in Chart PG&E – 3 includes NEM customers, which means that the average monthly usage of these categories is net of behind the meter generation. Despite the contribution of behind the meter generation, the average monthly usage for the group as a whole is always greater than the average for the full residential population.

Chart PG&E – 3: E-9A Monthly Usage with NEM

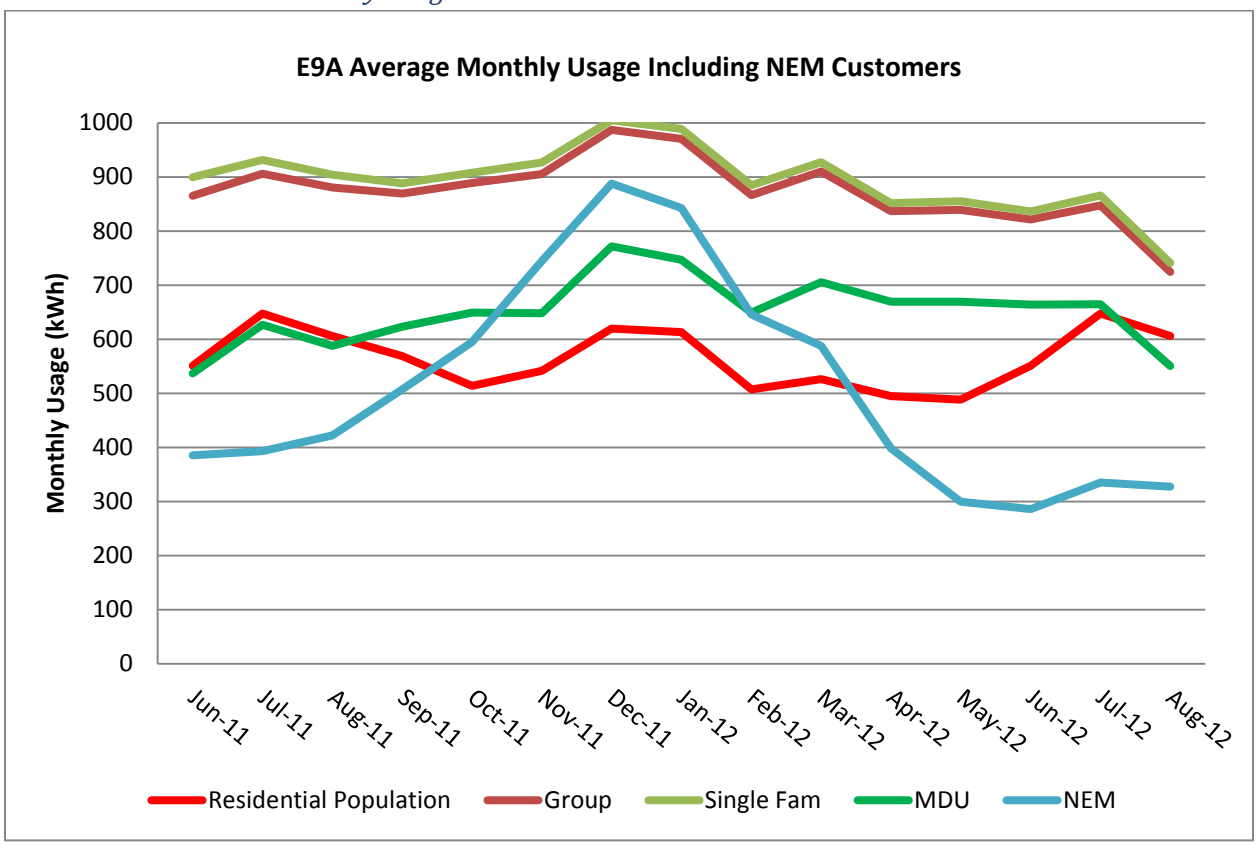


Chart PG&E – 4, which excludes NEM customers, is a more appropriate comparison because it does not include behind the meter generation. Consistent with what one should expect as a result of PEV ownership, Chart PG&E – 4 shows a sharp increase in the average PEV household usage as compared to the average PG&E residential customer. During the study period, non-NEM customers on E-9A used an average of 56% more energy than the full residential population (875 kWh per month versus 566 respectively). This amounts to an average increase of 309 kWh per month, a number that is consistent with the 248 kWh average monthly usage of PEV only customers only the separately metered E-9B rate (see Chart PG&E – 5).

Chart PG&E – 4: E-9A Monthly Usage with NEM Segregated

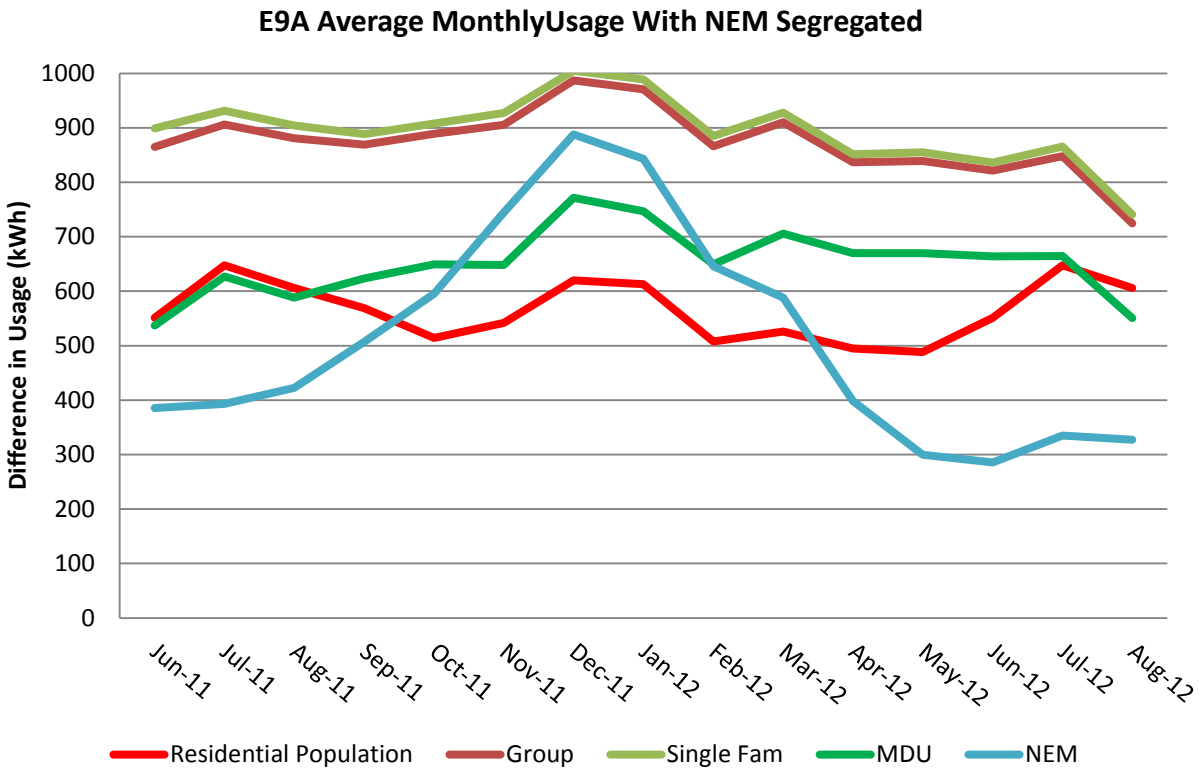
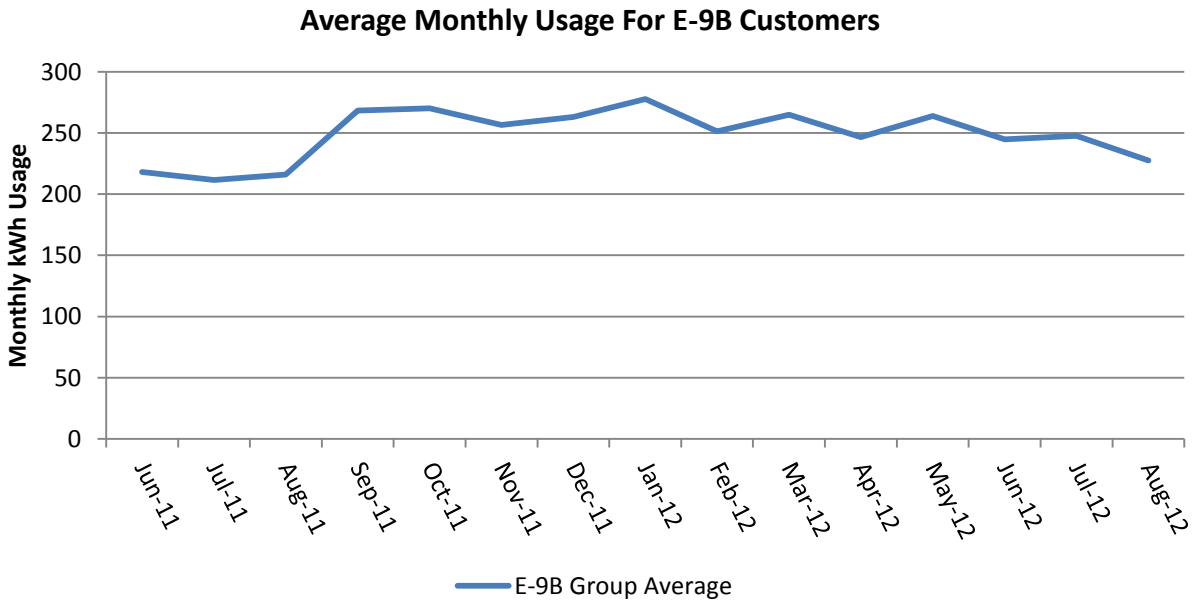


Chart PG&E – 5: E-9B Monthly Usage



Average Usage during Time of Use Periods for Whole House PEV Rate

TOU PEV rates are designed to discourage charging during on-peak hours and instead encourage charging during off-peak hours when the grid is less stressed and generation costs are lower. For both E-9A and E-9B customers, the time of use periods are defined in Table PG&E – 1.

One useful way to determine whether the TOU PEV rates are achieving their goal of avoiding peak PEV charging is to measure the distribution of charging in the various time periods. Given that NEM customers have a very unique usage profile, they are segregated from all other E-9A customers groups in Tables PG&E – 4 and 5. NEM customers are not segregated in the E-9B rate class due to much lower penetration. Due to the smaller customer counts on E-9B, no subcategories are shown (e.g. single family or MDU).

Table PG&E – 4: Share of On-Peak Usage by Customers on PEV Rates E-9A and E-9B

	Percentage of Usage Occurring in the On-Peak Period					
		E-9A Customers				E-9B Cust.
Month/ Year	Residential Population	Group Excluding NEM	Single Family Excluding NEM	MDU Excluding NEM	NEM	Group Including NEM
Jun-11	26%	20%	20%	14%	12%	5%
Jul-11	26%	21%	21%	17%	9%	5%
Aug-11	29%	20%	21%	16%	10%	4%
Sep-11	26%	20%	21%	15%	13%	9%
Oct-11	23%	15%	15%	13%	11%	5%
Nov-11	0%	3%	3%	2%	2%	1%
Dec-11	n/a	n/a	n/a	n/a	n/a	0%
Jan-12	n/a	n/a	n/a	n/a	n/a	0%
Feb-12	n/a	n/a	n/a	n/a	n/a	0%
Mar-12	n/a	n/a	n/a	n/a	n/a	0%
Apr-12	0%	4%	4%	3%	0%	1%
May-12	21%	17%	18%	15%	1%	6%
Jun-12	26%	21%	21%	19%	4%	8%
Jul-12	26%	21%	21%	19%	8%	9%
Aug-12	29%	22%	22%	19%	12%	11%

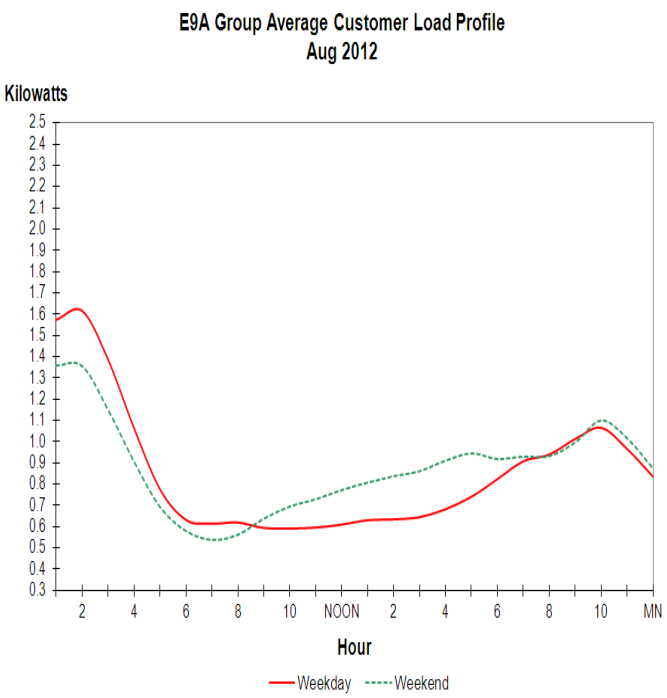
Table PG&E – 5: Share of Off-Peak Usage by Customers on PEV Rates E-9A and E-9B

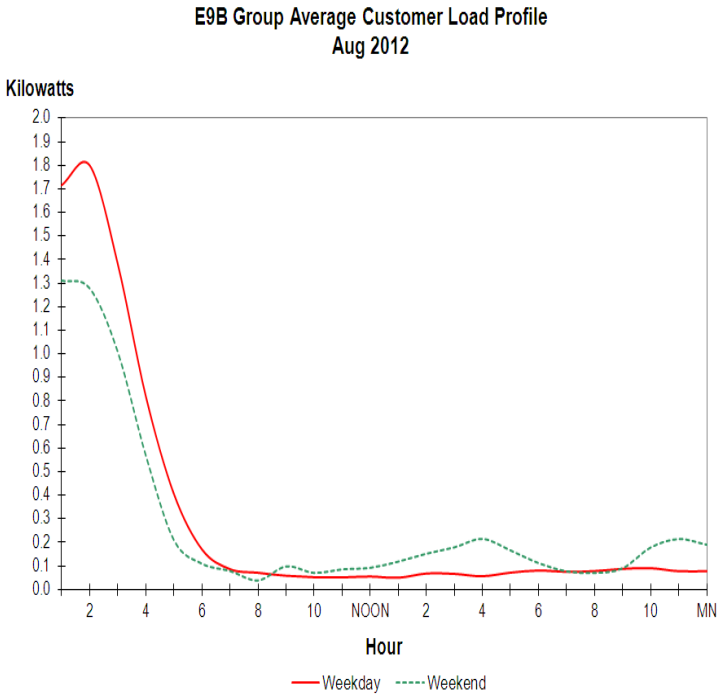
	Percentage of Usage Occurring in the Off-Peak Period					
		E-9A Customers				E-9B Cust.
Month/ Year	Residential Population	Group Excluding NEM	Single Family Excluding NEM	MDU Excluding NEM	NEM	Group Including NEM
Jun-11	37%	45%	45%	56%	70%	80%
Jul-11	39%	46%	46%	52%	75%	84%
Aug-11	35%	48%	47%	54%	75%	87%
Sep-11	38%	48%	48%	55%	72%	75%
Oct-11	41%	51%	50%	57%	68%	79%
Nov-11	42%	50%	50%	52%	59%	75%
Dec-11	36%	49%	49%	51%	55%	76%
Jan-12	39%	51%	51%	50%	56%	73%
Feb-12	38%	52%	52%	52%	62%	75%
Mar-12	35%	51%	51%	53%	67%	68%
Apr-12	36%	49%	49%	53%	76%	75%
May-12	44%	48%	47%	52%	87%	79%
Jun-12	37%	46%	47%	50%	84%	80%
Jul-12	39%	46%	46%	51%	78%	77%
Aug-12	35%	46%	46%	51%	73%	75%

The data shows that a smaller percentage of the whole house usage of customers on the E-9A rate is in the on-peak and a larger percentage is in the off-peak as compared to customers not on a PEV rate. Furthermore, separately metered E-9B customers are completing 77% of their charging in the off-peak period on average and just 7% during the on-peak period. This clearly suggests that customers on the PEV rates are charging during the off-peak periods.

Average Load Profiles for PEV Rates

Depicted below are the average weekday and weekend load profiles for the E-9A and E-9B rate groups for August 2012.





Non-Coincident Peak Load

The average non-coincident peak was slightly more than 1kW higher for the E-9A group category compared to the average residential peak.[31] This was slightly higher for single family customers and lower for multi-family customers. Table PG&E –6 below displays the summer and winter comparison of the average non-coincident peak for the E-9B categories and the full residential population.

Table PG&E – 6: Seasonal Average Non-Coincident Peak Load

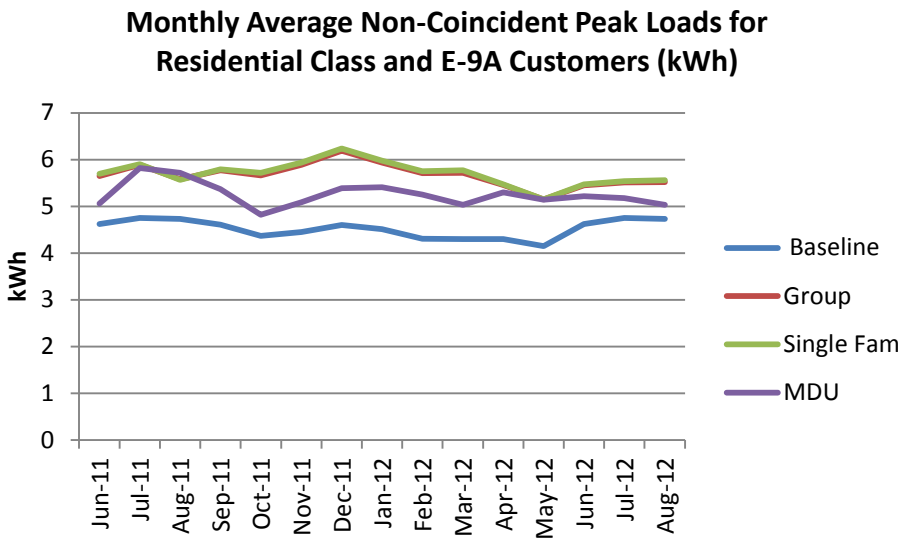
Seasonal Average Non-Coincident Peak Load					
Season	**Residential Population**	**E-9A Customers**			**E-9B Cust.***
		Group	**Single Family**	**MDU**	**Group**
Summer Avg.	4.70	5.60	5.62	5.34	4.28
Winter Avg.	4.47	5.95	5.99	5.35	Less Than 15 Cust.

***This E-9B data is based on just four months and an average of 30 customers and should be interpreted with caution.** The load research sample for the E-9B group exceeded the fifteen customer minimum only during July 2012 -August 2012, so this data is based on only those four months. Furthermore, the average count in the sample during that period was only 30 customers.*

[31] The average non-coincident peak was calculated by denoting the maximum hourly interval for each account within the month. These maximum values were then summed for each category. The average is then calculated by dividing the total by the number of customers. The average non-coincident peak is therefore an approximation of the maximum demand for customer in each stratum.

Chart PG&E - 7 shows the monthly non-coincident peak loads for the E-9A customers. E-9B customers are not shown due to data limitations.

Chart PG&E – 7: Monthly Average Non-Coincident Peak Loads for Residential Class and E-9A Customers (kWh)



This data suggests that, despite the fact that charging is primarily occurring in the off-peak hours, the average household with a PEV will have a higher maximum demand that must be accommodated by the electric distribution system as compared to the average household without a PEV.

Diversified Peak Load

The time of diversified peak load gives the time that the group peaks as a whole. The time of diversified (or group) peak load is generally the same for all categories of E-9A and E-9B customers. Table PG&E – 7 shows that the diversified peak load occurs between midnight and 2:00 am for all categories in all months for both rates. This clearly suggests that customers on the PEV rates are charging during the off-peak periods.

Table PG&E – 7: Time of Diversified Peak and Associated Load

	Time of Diversified Peak and Associated Load					
	Res. Population		E-9A Group		E-9B Group*	
Month	**Time**	**kW**	**Time**	**kW**	**Time**	**kW**
Jun-11	6:30 PM	1.72	1:00 AM	2.31	Fewer Than 15 Customers in Load Research Sample	
Jul-11	7:00 PM	1.65	2:00 AM	2.35		
Aug-11	7:00 PM	1.86	2:00 AM	2.52		
Sep-11	6:30 PM	1.59	1:00 AM	2.69		
Oct-11	7:30 PM	1.15	2:00 AM	2.73		
Nov-11	7:00 PM	1.29	2:00 AM	2.83		
Dec-11	7:00 PM	1.34	2:00 AM	2.83		
Jan-12	6:30 PM	1.26	2:00 AM	2.84		
Feb-12	7:00 PM	1.20	2:00 AM	2.69		
Mar-12	7:00 PM	1.16	2:00 AM	2.57		
Apr-12	7:30 PM	1.10	2:00 AM	2.38		
May-12	7:30 PM	1.01	2:00 AM	2.28	2:00 AM	2.36
Jun-12	6:30 PM	1.72	2:00 AM	2.16	2:00 AM	2.61
Jul-12	7:00 PM	1.65	2:00 AM	2.23	1:00 AM	2.58
Aug-12	7:00 PM	1.86	2:00 AM	1.79	1:00 AM	2.36

***This E-9B data is based on just four months and an average of 30 customers and should be interpreted with caution.** The load research sample for the E-9B group exceeded the fifteen customer minimum only during July 2012 -August 2012, so this data is based on only those four months. Furthermore, the average count in the sample during that period was only 30 customers.*

This suggests that although the early adopter PEV customers may have a higher average maximum demand, those customers on the PEV rates tend to hit their maximum demand while non-PEV customers are at their lowest usage. Thus, there is a diversity benefit created by the TOU rates. However, at the most local level service assessment level perspective (i.e. a single household or set of households serviced by a single transformer), the value of this diversity is limited by the fact that the distribution system must still be prepared to accommodate PEV charging during the peak period since these customers can, and occasionally do, charge during those times.

Average Load Coincident with System Peak

The average load coincident with system peak is the average load occurring at the same time that the system peak occurs. The system peak days and times were used to extract the appropriate hourly load at the time of system peak. The average group load coincident with system peak was calculated taking the total group load and dividing by the number of customers.

The average load coincident with system peak amongst the general population is very similar to that of each E-9A category (See Table PG&E – 8). This suggests that, for this particular group of early adopters, customers on a PEV rate are not doing a substantial amount of charging during the on-peak period. E-9B data (See Table PG&E – 9) is shown for illustration purposes; however, the sample sizes are very small.

Table PG&E – 8: Average Usage Coincident with the System Peak (kW)

	E-9A			*E-9B*
Residential Population	**Group**	**SF**	**MDU**	***Group****
1.27	1.24	1.26	1.01	*0.16*

***This E-9B data is based on just four months and an average of 30 customers and should be interpreted with caution.** The load research sample for the E-9B group exceeded the fifteen customer minimum only during July 2012 -August 2012, so this data is based on only those four months. Furthermore, the average count in the sample during that period was only 30 customers.*

Table PG&E – 9: Average Usage Coincident with the System Peak (kW)

	E-9A			*E-9B*
Residential Population	**Group**	**SF**	**MDU**	***Group****
1.27	1.24	1.26	1.01	*0.16*

**The E-9B data is shown for illustrative purposes only and should not be used for policymaking. The load research sample for the E-9B group exceeded the fifteen customer minimum only during July 2012 -August 2012, so this data is based on only those four months. Furthermore, the average count in the sample during that period was only 30 customers.*

SCE

Whole House PEV Rates:

The TOU-D-TEV rate is designed for residential customers who have their typical household load with electric vehicle charging on the same meter. The Home & Electric Vehicle rate plan uses a tiered structure similar in some ways to the standard residential rate. As of the date of this report, this rate plan has only two tiers, while the standard residential rate has five tiers. With any tiered rate plan, the cost per kilowatt hour rises as more electricity is used in a billing period. With this rate plan, rates change seasonally too, rising in summer and dropping in winter. This rate offers energy prices for different time of use (TOU) periods. Table SCE – 1 shows these TOU periods.

Table SCE – 1: TOU-D-TEV Time Periods

TOU-D-TEV Time Periods

On Peak	10:00 a.m. - 6:00 p.m., weekdays all year, except holidays.
Super Off Peak	12:00 (midnight) - 6:00 a.m., daily
Off-Peak	All other hours.

For purposes of this report, the TOU-D-TEV customers are segmented into various categories. Some load profile and demand metrics for the average residential customer are also provided to serve as a comparison to the TOU-D-TEV customers. Although the average residential customer metrics are from the same month as those presented for the electric vehicle rates of 2011 and 2012, the average residential customer metrics are from the year 2010.

Another important consideration is the high percentage of dual participation in NEM and TOU-D-TEV rate. NEM customers represent between 17%-24% of the TOU-D-TEV population during the study period. Therefore to avoid the confounding effects of the NEM onsite generation, NEM customers are excluded from some categories. Table SCE – 2 shows the TOU-D-TEV and average domestic customer categories.

Table SCE – 2: TOU-D-TEV & Average Domestic Customer Categories

TOU-D-TEV & Average Domestic Customer Categories

Category	Description
Average Domestic Customer categories	
D	Average Residential customer.
D-SF	Average Single Family Residential customer.
TOU-D-TEV categories	
Group	All customers on the TOU-D-TEV rate.
Group: Non-NEM	All customers on the TOU-D-TEV rate who are not Net Energy Metering customers.
Single	All single family customers on the TOU-D-TEV rate.
Single: Non-NEM	All single family customers on the TOU-D-TEV rate who are not Net Energy Metering customers.
Multi	All multi-family customers on the TOU-D-TEV rate.
NEM	All Net Energy Metering customers on the TOU-D-TEV rate.
Demand Response	All TOU-D-TEV customers participating in demand response programs.

* Please note that these categories may not be mutually exclusive. For example, a NEM customer that is also on DR would appear in both categories.

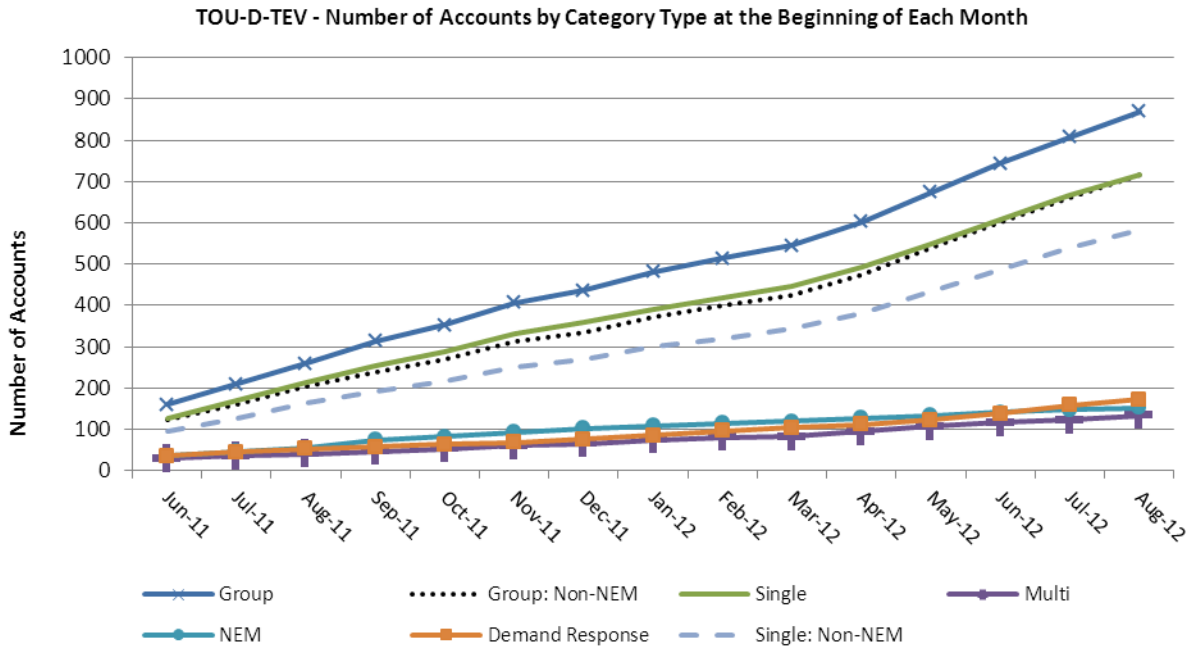
SCE added a new category representing average "single family (SF)" residential customers in tables and graphs (noted as "D-SF") for this report. This is an addition from the format adopted by the three IOUs for the quarterly reports. Since the majority of PEV owners reside in single family dwellings, comparison of average residential and average PEV owners does not provide accurate results, i.e., it shows PEV load is more than what it really is. Therefore, this new Group was added to provide apples to apples comparison. In addition a "Non-NEM" group is created to provide more accurate comparison given the difference in NEM profiles as noted by PG&E.

Growth of the Whole House PEV Rate

There was a steady increase in all TOU-D-TEV customer categories for the period studied. The number of accounts in the TOU-D-TEV group as a whole increased 443% at the last reported month compared to

the base month. The number of accounts in all categories increased by 322%-515% compared to the base month. Chart SCE – 1 shows the number of accounts at the beginning of each month.

Chart SCE – 1: TOU-D-TEV - Number of Accounts by Category Type at the Beginning of Each Month



Average Monthly Usage of Whole House PEV Rate Compared to the Average for the Residential population

The average monthly usage of the TOU-D-TEV rate categories was computed for each month. As expected, multi-family customers have the lowest average monthly usages compared to all other categories except for some months for NEM customers when recorded usage is low due to high NEM generation, especially in the summer months. Usage for the demand response category is slightly lower than the average for the group during the winter months and higher during the summer.

The average monthly usage for all TOU-D-TEV customers (Group category) is always higher than the monthly usage for the average domestic customer (between 310 – 582 kWh higher for the study period). On average for TOU-D-TEV, the Single family, non-NEM customer category used between 383-614 kWh more energy per month than the average single family domestic customer. This represents between 1.5 -2.08 times more energy than the average single family domestic customer. Table SCE – 3 displays the average monthly usages for the TOU-D-TEV categories.

Table SCE –3: TOU-D-TEV - Average Monthly Usage (kWh) by Category

TOU-D-TEV: Average Monthly Usage (kWh)

	Average Domestic Customer		TOU-D-TEV: Non-NEM		TOU-D-TEV				
Month	D	D - SF	Group: Non-NEM	Single: Non-NEM	Group	Single	Multi	NEM	Demand Response
Jun-11	543	601	939	1,023	853	902	662	555	881
Jul-11	687	767	1,133	1,222	1,032	1,086	798	685	1,091
Aug-11	703	785	1,118	1,194	1,032	1,080	810	709	1,045
Sep-11	630	700	1,039	1,113	968	1,018	753	744	1,000
Oct-11	539	600	986	1,052	938	984	734	778	950
Nov-11	541	602	963	1,025	928	972	732	809	928
Dec-11	614	685	1,071	1,141	1,076	1,118	887	1,095	1,099
Jan-12	561	621	1,009	1,073	1,004	1,044	823	985	996
Feb-12	483	534	918	975	910	948	745	881	911
Mar-12	501	556	1,024	1,101	946	991	733	769	921
Apr-12	468	519	944	1,019	865	912	645	681	844
May-12	467	514	995	1,068	917	964	694	730	905
Jun-12	543	601	983	1,049	962	1,016	715	872	988
Jul-12	687	767	1,080	1,150	1,054	1,111	789	938	1,084
Aug-12	703	785	1,315	1,399	1,285	1,356	949	1,145	1,364

Average Usage during Time of Use Periods for Whole House PEV Rate

For TOU-D-TEV customers, time of use periods are defined as follows: 1) *On-peak*: 10:00 a.m. - 6:00 p.m. weekdays all year, except holidays 2) *Super Off-Peak*: 12:00 Midnight – 6:00 a.m. all year, everyday 3) *Off-Peak*: All other hours – all year, everyday.

There is an increase in on-peak usage as a percentage from summer 2011 to summer 2012 (see Table SCE-4). While the percentage of super off peak usage has declined, from 35% in June 2011 to 32% in June 2012 (or 33% in August 2011 to 28% in August 2012), this may be due to a difference mix of customers that are on this rate in 2012 comparing to the small number of early adopter customers seen in 2011 rather than an increase in percentage of on-peak usage for an average customer. As adoption of this rate continues to grow, newer customers may continue this trend of decreased off peak usage.

The mean on-peak, super-off, and off peak usage percentages are calculated for the 15 months. An average of 16% of usage occurs during the on-peak period, 34% of usage during super-off and 50% of total usage during the off-peak period for the entire group. However, NEM customers have the lowest percentage of on peak usage. This is because NEM customers use the electricity they generate during the on-peak period.

Table SCE – 4: TOU-D-TEV – On Peak TOU Distribution

TOU-D-TEV: On Peak TOU Distribution

	TOU-D-TEV: Non-NEM		TOU-D-TEV				
Month	**Group: Non-NEM**	**Single: Non-NEM**	**Group**	**Single**	**Multi**	**NEM**	**Demand Response**
Jun-11	19%	20%	17%	17%	14%	4%	17%
Jul-11	17%	18%	16%	16%	14%	5%	15%
Aug-11	20%	21%	18%	18%	15%	6%	17%
Sep-11	18%	19%	16%	17%	14%	7%	15%
Oct-11	16%	17%	15%	15%	13%	7%	13%
Nov-11	16%	16%	14%	14%	13%	9%	13%
Dec-11	16%	17%	15%	15%	14%	11%	14%
Jan-12	17%	17%	15%	16%	14%	9%	14%
Feb-12	16%	16%	14%	14%	13%	8%	13%
Mar-12	17%	17%	14%	14%	12%	5%	12%
Apr-12	17%	18%	14%	15%	12%	4%	13%
May-12	18%	19%	15%	15%	13%	4%	14%
Jun-12	19%	19%	19%	19%	17%	17%	18%
Jul-12	19%	19%	19%	19%	18%	16%	18%
Aug-12	22%	23%	22%	22%	21%	19%	21%

* On Peak period is defined as 10:00 a.m. - 6:00 p.m., weekdays all year, except holidays.

Table SCE – 5: TOU-D-TEV – Super Off Peak TOU Distribution

TOU-D-TEV: Super Off Peak TOU Distribution

	TOU-D-TEV: Non-NEM		TOU-D-TEV				
Month	**Group: Non-NEM**	**Single: Non-NEM**	**Group**	**Single**	**Multi**	**NEM**	**Demand Response**
Jun-11	33%	33%	35%	35%	37%	49%	36%
Jul-11	31%	31%	33%	33%	33%	44%	36%
Aug-11	31%	31%	33%	32%	36%	44%	34%
Sep-11	32%	32%	34%	34%	37%	42%	37%
Oct-11	34%	33%	36%	35%	38%	43%	39%
Nov-11	33%	33%	34%	34%	36%	40%	39%
Dec-11	32%	31%	33%	33%	34%	37%	37%
Jan-12	33%	32%	34%	34%	35%	39%	38%
Feb-12	34%	34%	36%	36%	37%	42%	40%
Mar-12	34%	34%	37%	37%	37%	45%	41%
Apr-12	34%	33%	37%	37%	38%	47%	40%
May-12	34%	33%	37%	37%	39%	47%	39%
Jun-12	31%	30%	32%	32%	34%	37%	33%
Jul-12	29%	29%	30%	30%	32%	35%	30%
Aug-12	27%	27%	28%	28%	29%	32%	28%

* Super Off Peak period is defined as 12:00 (midnight) - 6:00 a.m., daily.

Table SCE – 6: TOU-D-TEV – Off Peak TOU Distribution

TOU-D-TEV: Off Peak TOU Distribution

	TOU-D-TEV: Non-NEM		TOU-D-TEV				
Month	**Group: Non-NEM**	**Single: Non-NEM**	**Group**	**Single**	**Multi**	**NEM**	**Demand Response**
Jun-11	48%	48%	48%	48%	49%	48%	47%
Jul-11	51%	51%	51%	51%	53%	50%	50%
Aug-11	49%	49%	49%	49%	49%	50%	48%
Sep-11	49%	49%	49%	49%	49%	51%	48%
Oct-11	50%	50%	50%	50%	50%	49%	48%
Nov-11	51%	52%	51%	51%	51%	52%	48%
Dec-11	52%	52%	52%	52%	52%	52%	49%
Jan-12	50%	50%	51%	50%	51%	51%	48%
Feb-12	50%	50%	50%	50%	50%	50%	47%
Mar-12	49%	49%	49%	49%	51%	50%	47%
Apr-12	49%	49%	49%	49%	49%	49%	47%
May-12	48%	48%	48%	48%	48%	48%	47%
Jun-12	50%	50%	49%	49%	49%	46%	49%
Jul-12	52%	52%	51%	51%	51%	49%	52%
Aug-12	51%	51%	50%	50%	50%	50%	51%

* Off Peak period is defined as all other hours that are not On Peak or Super Off Peak.

Average Load Profiles for Whole House PEV Rate

The TOU-D-TEV load profiles allow for further examination of electric vehicle charging during time of use periods.

Charts SCE – 2 &3 show the average load profile for the same TOU-D-TEV customer categories described previously. These profiles are given for one month in summer (August 2012) and one month in winter (March 2012). The bump in load occuring in the afternoon hours is likely due to customers coming home from work and increasing usage, which also explains why usage during off-peak hours is the highest. The load profile also shows an increase in load around 11 p.m. which is most likely due to charging of the electric vehicle and accounts for the high percentage of usage occuring during the super-off peak period. Furthermore, it appears that customers are starting their charging towards the end of the off-peak period and the majority of charging occuring during the super-off peak times (12 midnight – 6:00 a.m.). Therefore on average, customers seem to respond to time of use periods regardless of season. All categories appear to have the same load shape, except for slight variation in demand at different time periods. Participants of demand response programs do not vary significantly in load shape from the average TOU-D-TEV customer. Although multi-family customers have a similar load shape as other TOU-D-TEV categories, their demand is lower throughtout the course of the day.

Also included are the load profiles for the average single family residential customer (See Charts SCE – 4 & 5). When these load profiles are compared to TOU-D-TEV profiles, the charging patterns during night time and early morning hours are more obvious. These graphs also have a category called “Non EV rate with Car”. These are customers who aren’t on a electric vehicle rate, but are instead on a regular tiered

domestic rate. This represents the same 260 customers for both March and August 2012. SCE has been informed that they have an electric vehicle either by the customer themselves or by a third party. Although their load is higher during early morning hours than the average single family residential customer, it is not as high as the TOU-D-TEV customer during the super off-peak hours. This shows that the customers who have an electric vehicle but remain on a regular domestic rate, are not charging as much during super off peak hours compared to those on EV rates.

Chart SCE – 2: TOU-D-TEV Average Load Profile for March 2012

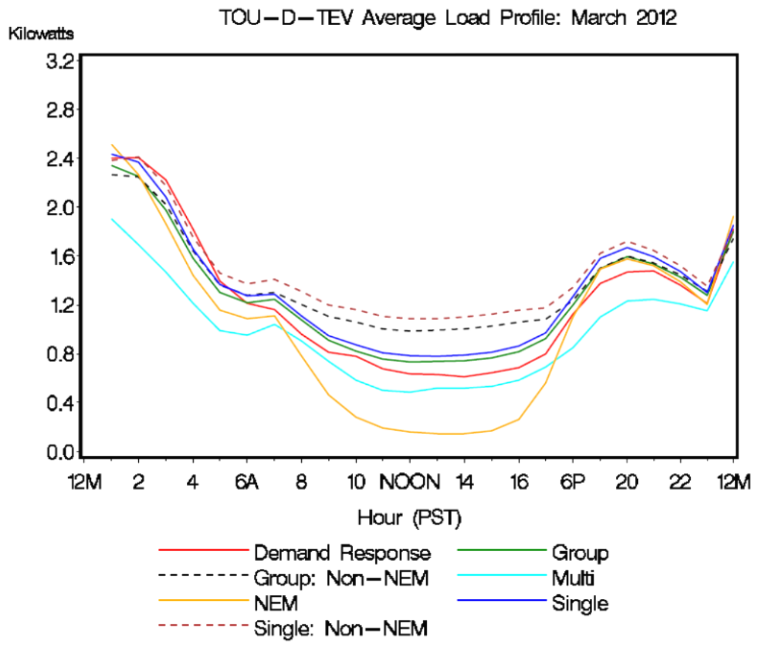


Chart SCE – 3: TOU-D-TEV Average Load Profile for August 2012

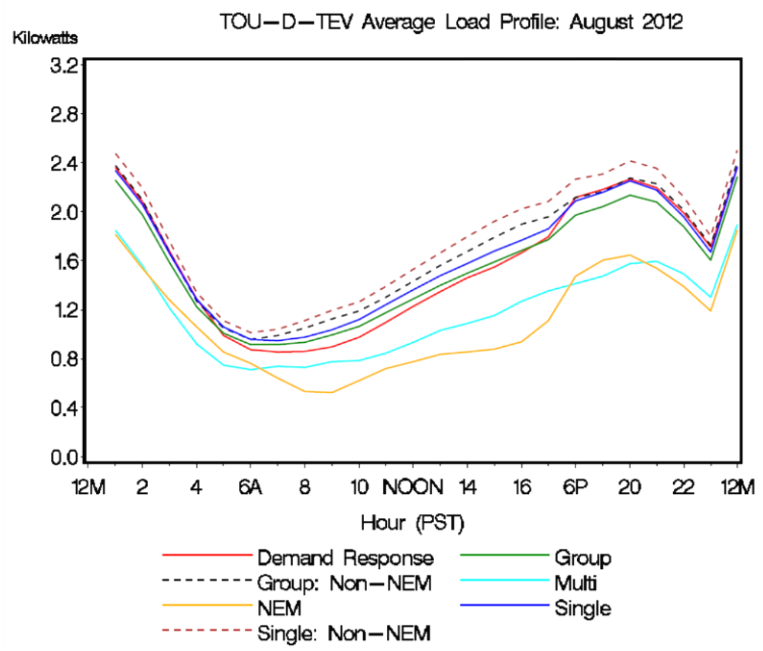


Chart SCE – 4: TOU-D-TEV and All Single Family Residence Average Load Profile for March 2012

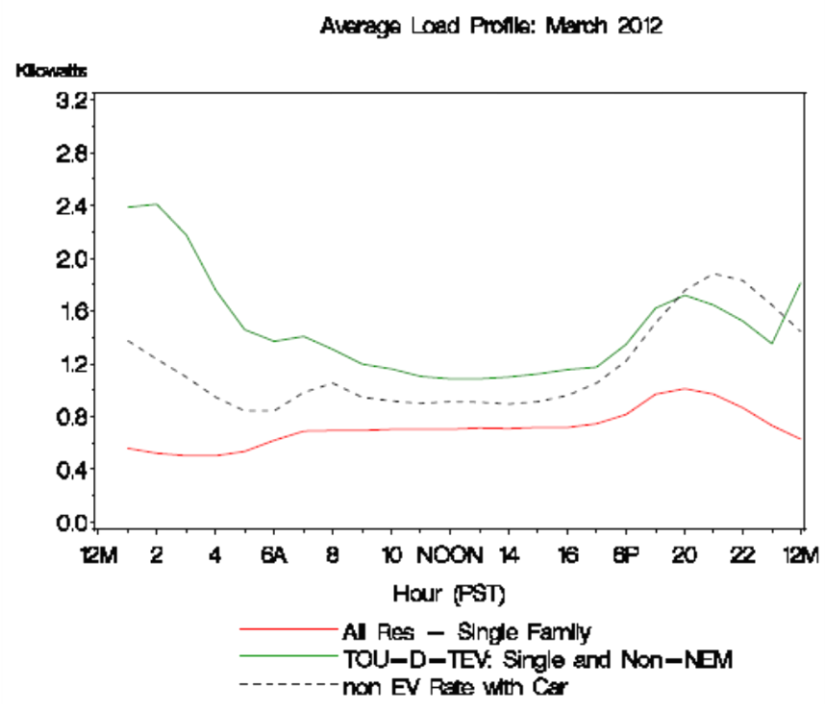
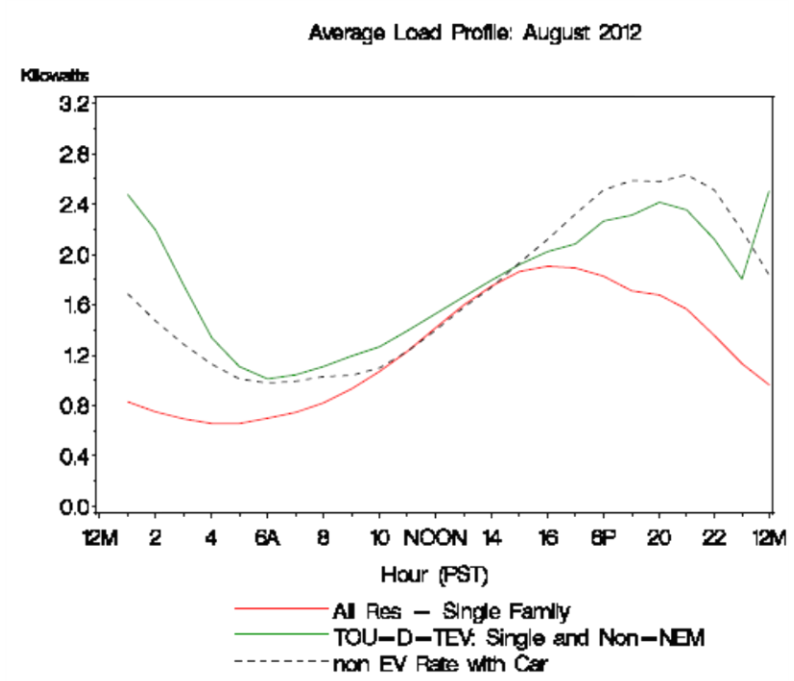


Chart SCE – 5: TOU-D-TEV and All Single Family Residence Average Load Profile for August 2012



Average Whole House Non-Coincident Peak Load

The average non-coincident peak was approximately 2kW higher for the TOU-D-TEV group category compared to the average residential peak.[32] This was slightly higher for Single family and demand response customers and lower for Multi-family customers. The average non-coincident peak was lower for NEM customers in the summer months compared to winter. The non-NEM group category has a higher non-coincident peak load (5.83 – 7.54 kW) than the average domestic customer (3.71 – 4.92 kW). This is approximately 1.5 times higher than the average domestic customer. Table SCE - 7 displays the average non-coincident peaks for the reported time frame.

[32] The average non-coincident peak was calculated by denoting the maximum hourly interval for each account within the month. These maximum values were then summed for each category. The average is then calculated by dividing the total by the number of customers. The average non-coincident peak is therefore an approximation of the maximum demand for customer in each stratum.

Table SCE – 7: TOU-D-TEV Average Non-Coincident Peak

TOU-D-TEV: Average Non-Coincident Peak (kW/ Customer)

	Average Domestic Customer		TOU-D-TEV: Non-NEM		TOU-D-TEV				
Month	D	D - SF	Group: Non-NEM	Single: Non-NEM	Group	Single	Multi	NEM	Demand Response
Jun-11	4.23	4.55	6.17	6.41	6.03	6.2	5.38	5.53	6.06
Jul-11	4.88	5.35	6.98	7.29	6.85	7.06	5.9	6.37	7.1
Aug-11	4.85	5.30	7.11	7.42	6.97	7.19	5.92	6.44	7.61
Sep-11	4.92	5.39	6.66	6.99	6.64	6.89	5.56	6.58	7.35
Oct-11	4.43	4.79	6.26	6.51	6.28	6.46	5.45	6.32	6.29
Nov-11	4.29	4.52	6.06	6.31	6.14	6.32	5.36	6.41	6.28
Dec-11	4.23	4.46	6.11	6.35	6.39	6.52	5.79	7.29	6.57
Jan-12	3.95	4.12	5.83	6.03	6.12	6.26	5.5	7.1	6.22
Feb-12	3.82	3.96	5.88	6.11	6.13	6.29	5.46	7	6.22
Mar-12	3.82	4.00	6.03	6.28	6.01	6.15	5.37	5.97	6
Apr-12	3.71	3.88	5.96	6.29	5.97	6.19	4.95	6	5.92
May-12	3.83	4.05	6.05	6.3	6.07	6.26	5.18	6.13	6.02
Jun-12	4.23	4.55	6.18	6.42	6.2	6.42	5.25	6.3	6.26
Jul-12	4.88	5.35	6.69	6.97	6.69	6.93	5.54	6.65	6.96
Aug-12	4.85	5.30	7.54	7.85	7.55	7.84	6.17	7.59	8.1

Time and Average Diversified Peak Load

The time of diversified peak load gives the time that the group peaks as a whole. The time of diversified (or group) peak load is mostly the same for all categories within the same month (See Tables SCE – 8 & 9). The diversified peak load does not change a significant amount across months and occurs between midnight and 2:00 am for all categories. This suggests that on average one TOU-D-TEV category is not more responsive than another to a time of use rate. It also shows that these customers are responsive to a super off peak rate which begins at 12:00 midnight. For TOU-D-TEV customers, the super-off peak rate provides the lowest rate for charging purposes. While TOU-D-TEV customers peak in the early morning hours, domestic customers typically peak in the late afternoon or early evening hours (3:00 p.m. – 8:00 p.m.). The average diversified peak load is usually only slightly higher for TOU-D-TEV customers than the average domestic customer.

Table SCE – 8: TOU-D-TEV Time and Average Diversified Peak Load

TOU-D-TEV: Time and Average Diversified Peak Load (kW/Customer)

	TOU-D-TEV									
Month	**Group**		**Single**		**Multi**		**NEM**		**Demand Response**	
	kW/Cust	Time	kW/Cust	Time	kW/Cust	Time	kW/Cust	Time	kW/Cust	Time
Jun-11	2.1	1:00 AM	2.2	1:00 AM	1.9	1:00 AM	2.1	1:00 AM	2.4	1:00 AM
Jul-11	2.4	1:00 AM	2.5	1:00 AM	1.9	1:00 AM	2.4	1:00 AM	2.8	1:00 AM
Aug-11	2.4	1:00 AM	2.4	1:00 AM	2.2	1:00 AM	2.5	1:00 AM	2.6	1:00 AM
Sep-11	2.4	1:00 AM	2.4	1:00 AM	2.2	1:00 AM	2.5	1:00 AM	2.8	1:00 AM
Oct-11	2.3	1:00 AM	2.4	1:00 AM	2.1	1:00 AM	2.6	1:00 AM	2.5	1:00 AM
Nov-11	2.4	12:00 AM	2.4	1:00 AM	2.1	12:00 AM	2.6	12:00 AM	2.7	12:00 AM
Dec-11	2.5	12:00 AM	2.6	1:00 AM	2.3	12:00 AM	3	12:00 AM	2.9	12:00 AM
Jan-12	2.5	1:00 AM	2.5	1:00 AM	2.2	12:00 AM	2.9	12:00 AM	2.7	12:00 AM
Feb-12	2.6	1:00 AM	2.7	1:00 AM	2.3	12:00 AM	3	12:00 AM	2.8	12:00 AM
Mar-12	2.3	1:00 AM	2.4	1:00 AM	1.9	1:00 AM	2.5	1:00 AM	2.4	2:00 AM
Apr-12	2.2	1:00 AM	2.3	1:00 AM	1.8	1:00 AM	2.4	1:00 AM	2.4	1:00 AM
May-12	2.4	1:00 AM	2.4	1:00 AM	1.9	1:00 AM	2.6	1:00 AM	2.5	1:00 AM
Jun-12	2.1	1:00 AM	2.1	1:00 AM	1.8	1:00 AM	1.8	1:00 AM	2.2	1:00 AM
Jul-12	2	12:00 AM	2.1	12:00 AM	1.8	12:00 AM	1.7	12:00 AM	2.1	12:00 AM
Aug-12	2.3	12:00 AM	2.4	12:00 AM	1.9	12:00 AM	1.9	12:00 AM	2.4	12:00 AM

Table SCE –9: TOU-D-TEV (Non-NEM) & Average Domestic Customer Time and Average Diversified Peak Load

TOU-D-TEV (Non-NEM) & Average Domestic Customer: Time and Average Diversified Peak Load (kW/Customer)

	Average Domestic Customer				TOU-D-TEV: Non-NEM			
Month	**D**		**D-SF**		**Group: Non-NEM**		**Single: Non-NEM**	
	kW/Cust	Time	kW/Cust	Time	kW/Cust	Time	kW/Cust	Time
Jun-11	1.39	3:30 PM	2.00	4:30 PM	2.1	1:00 AM	2.3	2:00 AM
Jul-11	2.09	3:00 PM	2.97	4:00 PM	2.4	1:00 AM	2.6	1:00 AM
Aug-11	1.99	4:30 PM	2.98	5:00 PM	2.4	1:00 AM	2.4	1:00 AM
Sep-11	2.28	5:30 PM	3.23	6:30 PM	2.4	1:00 AM	2.4	2:00 AM
Oct-11	1.46	2:30 PM	2.07	3:30 PM	2.3	1:00 AM	2.4	2:00 AM
Nov-11	1.29	8:00 PM	1.80	6:00 PM	2.4	1:00 AM	2.5	1:00 AM
Dec-11	1.35	6:30 PM	1.90	6:30 PM	2.4	1:00 AM	2.5	1:00 AM
Jan-12	1.24	7:30 PM	1.75	7:00 PM	2.3	1:00 AM	2.5	1:00 AM
Feb-12	1.24	7:00 PM	1.74	7:00 PM	2.5	1:00 AM	2.6	1:00 AM
Mar-12	1.09	7:00 PM	1.54	8:00 PM	2.3	1:00 AM	2.4	2:00 AM
Apr-12	1.04	6:30 PM	1.46	7:30 PM	2.2	1:00 AM	2.3	1:00 AM
May-12	1.04	7:00 PM	1.50	8:00 PM	2.2	1:00 AM	2.3	1:00 AM
Jun-12	1.39	4:30 PM	2.00	4:30 PM	2.2	1:00 AM	2.2	1:00 AM
Jul-12	2.09	4:00 PM	2.97	4:00 PM	2.1	12:00 AM	2.2	12:00 AM
Aug-12	1.99	5:30 PM	2.98	5:00 PM	2.4	12:00 AM	2.5	12:00 AM

Average Load Coincident with System Peak

The average load coincident with system peak is the average load occurring at the same time that the system peak occurs. The system peak days and times were used to extract the appropriate hourly load at the time of system peak. The average group load coincident with system peak was calculated taking the total group load and dividing by the number of customers.

Table SCE – 10 shows that the average load coincident with system peak is very similar for the majority of TOU-D-TEV categories. Multi-family usage is lower in general compared to single family or group

metrics. NEM is also lower in summer months compared to winter months, which may again be due to onsite generation in the summer.

SCE's annual system peak usually occurs during the hot summer months. Single-family TOU-D-TEV customers who are not NEM have a lower average load coincident with the system peak compared to the average single family residential customer during summer months. Therefore it appears as though they are not contributing as much compared to the average single family residential customer during the hot summer months. One possible reason for this is that a higher percentage of TOU-D-TEV customers live in coastal zones compared to the entire residential population. Customers in mild temperature zones may be early adopters that have a shorter commute compared to customers in inland areas. For example, a higher percentage of customers reside in zone 6 compared to the entire residential population (see Table SCE – 11). Zone 6 is a coastal area. Therefore zone 6 customers may be less likely to turn on their air conditioning during hot summer months than all other residential customers and consequently contribute less to the system peak. In contrast, less TOU-D-TEV customers live in warmer inland regions (i.e. Zone 10) compared to the entire residential population, 10% vs. 20% respectively.

Table SCE –10: Average Load Coincident with System Peak (kW/customer)

TOU-D-TEV: Average Load Coincident with System Peak (kW/Customer)

	Average Domestic Customer		TOU-D-TEV: Non-NEM		TOU-D-TEV				
Month	D	D - SF	Group: Non-NEM	Single: Non-NEM	Group	Single	Multi	NEM	Demand Response
Jun-11	1.14	1.65	1.35	1.47	1.15	1.22	0.85	0.45	1.12
Jul-11	1.99	2.82	2.18	2.27	1.87	1.9	1.74	0.78	1.83
Aug-11	2.10	2.82	1.97	2.15	1.7	1.79	1.24	0.67	1.78
Sep-11	1.98	2.81	2.07	2.31	1.82	2	1.04	1.03	2.13
Oct-11	1.24	1.74	1.57	1.76	1.45	1.56	0.97	1.03	1.29
Nov-11	1.08	1.52	1.37	1.45	1.41	1.45	1.21	1.54	1.46
Dec-11	1.28	1.81	1.97	2.11	2.12	2.23	1.62	2.61	1.96
Jan-12	1.20	1.70	1.75	1.86	1.83	1.9	1.52	2.1	1.74
Feb-12	1.21	1.69	1.75	1.87	1.83	1.92	1.46	2.13	1.64
Mar-12	0.64	0.91	0.96	1.06	0.73	0.79	0.44	0.22	0.7
Apr-12	0.65	0.92	1.2	1.35	0.92	1.01	0.5	0.25	0.82
May-12	0.65	0.94	1.26	1.41	1	1.07	0.65	0.37	0.87
Jun-12	1.14	1.65	1.36	1.49	1.26	1.36	0.81	0.81	1.28
Jul-12	1.99	2.82	1.62	1.74	1.53	1.63	1.05	1.13	1.68
Aug-12	2.10	2.82	2.26	2.47	2.13	2.29	1.37	1.49	2.18

Table SCE –11: Percentage of PEV Customers by Zone.

Percentage of PEV customers by zone vs. Residential Population

Zone	TOU-D-TEV	TOU-EV-1	Residential Population
5	0%	0%	0%
6	38%	37%	19%
8	23%	27%	24%
9	25%	28%	21%
10	10%	5%	20%
13	1%	0%	4%
14	2%	1%	7%
15	1%	2%	3%
16	1%	2%	2%

* Percentages are based on all year end 2012 residential customers.
** SCE's baseline information can be found at:
http://www.sce.com/NR/sc3/tm2/pdf/ce63map.pdf

Separately Metered Electric Vehicle Rates

The TOU-EV-1 rate is designed for residential customers who have a separate meter exclusively for electric vehicle charging. Therefore, the TOU-EV-1 rate only reflects electric vehicle charging load. The second meter is installed at no additional cost, but the home's electrical infrastructure must be able to support it, often at significant customer expense. For this rate plan, lower rates apply during "off-peak" hours of 9:00 p.m. to 12:00 noon, and rates change seasonally. For usage between noon and 9 p.m., rates are higher in summer. Table SCE – 12 shows the TOU periods for the TOU-EV-1 rate.

Table SCE – 12: TOU-EV-1 Time Periods

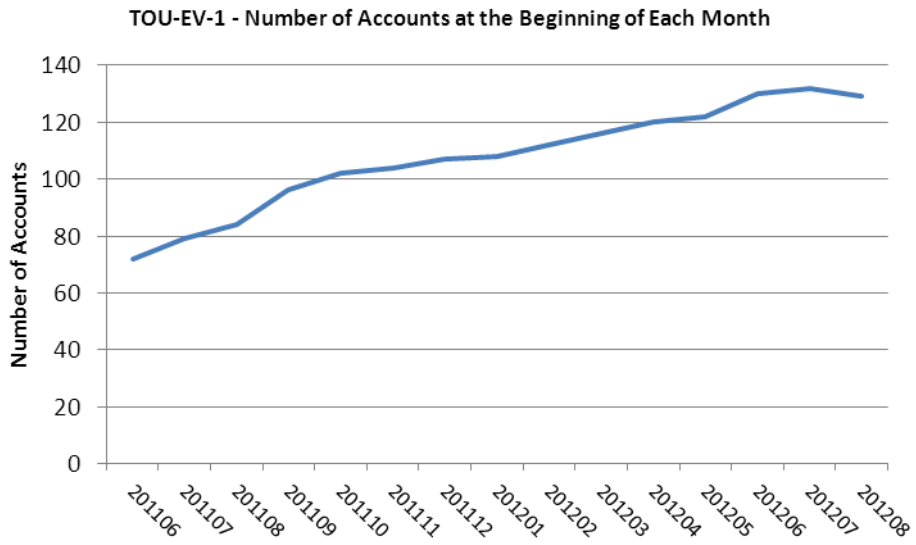
TOU-EV-1 Time Periods

On Peak	12:00 noon - 9:00 p.m., daily
Off-Peak	All other hours.

Adoption of Separately Metered PEV Rates

. During the study period SCE found a steady increase in the number of TOU-EV-1 customers. While TOU-D-EV accounts grew by 443%, the number of accounts in the TOU-EV-1 group increased by 80% at end of the study period compared to the beginning. (See Chart SCE – 6) Customers may be less likely to enroll on a TOU-D-TEV rate due to the high cost of installation.

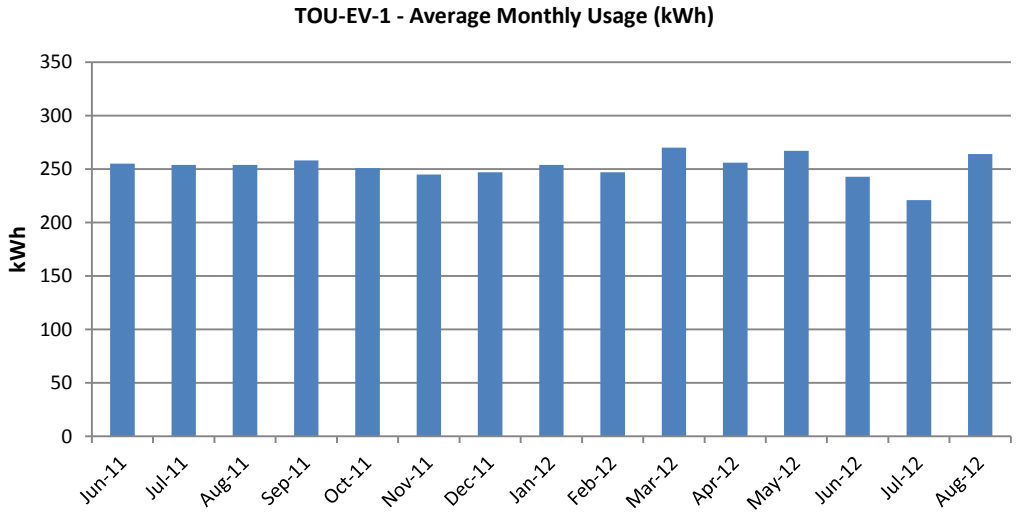
Chart SCE – 6: TOU-EV-1 Number of Accounts



Average Monthly Usage of the Separately Metered PEV Rates

The average monthly usage for TOU-EV-1 customers is consistent throughout the months (See Chart SCE – 7). This suggests that customers are usually charging the same amount regardless of season and do not vary their load or PEV charging from month to month.

Chart SCE – 7: TOU-EV-1 - Average Monthly Usage



Usage during Time of Use Periods

For EV-1 customers, time of use periods are defined as follows: 1) *On-peak*: 12:00 noon -9:00 p.m. , everyday 2) *Off-Peak*: All other hours - all year, everyday.

The separately metered customers are highly compliant with charging during time of use periods. They are charging their cars approximately 90% of the time during off peak hours.

Table SCE – 13: TOU-EV-1: Usage during Time of Use Periods

TOU-EV-1: Usage during Time of Use Periods

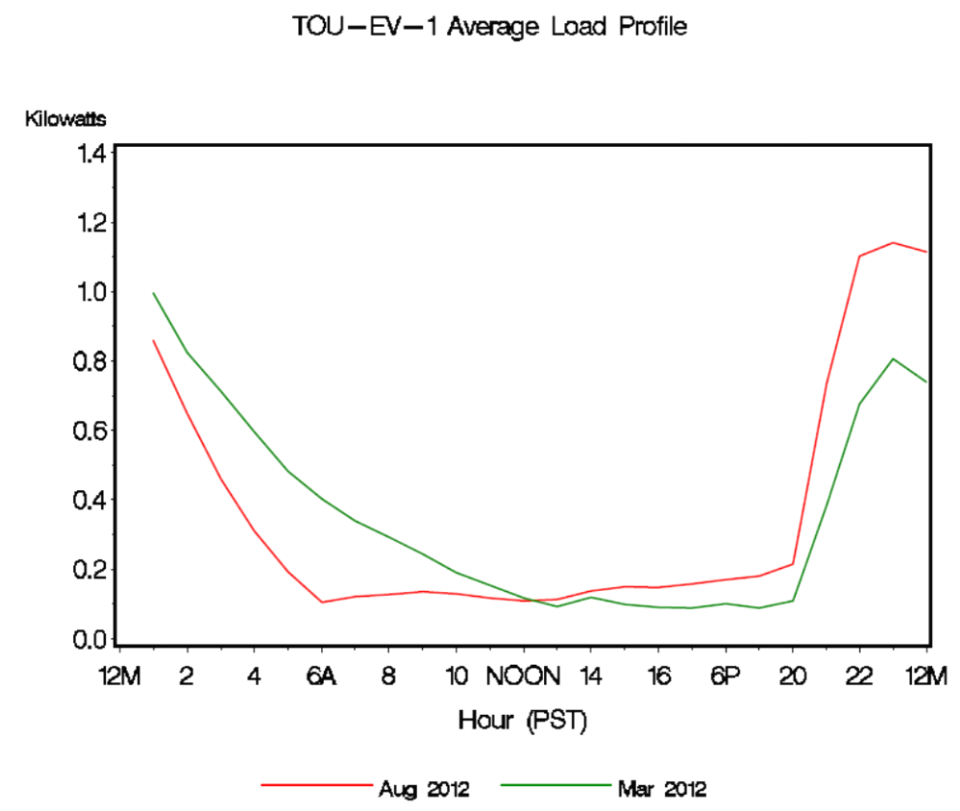
Month	On Peak	Off Peak
Jun-11	13%	87%
Jul-11	14%	86%
Aug-11	12%	88%
Sep-11	13%	87%
Oct-11	12%	88%
Nov-11	12%	88%
Dec-11	13%	87%
Jan-12	13%	87%
Feb-12	14%	86%
Mar-12	10%	90%
Apr-12	9%	91%
May-12	10%	90%
Jun-12	13%	87%
Jul-12	14%	86%
Aug-12	16%	84%

Average Load Profiles for Separately Metered PEV Rates

The average load profiles allows for further examination of electric vehicle charging during time of use periods. Chart SCE – 8 shows examples of average load profiles for one month of summer and winter are provided below.

There is a spike in PEV load around 10 p.m. for TOU-EV-1 customers suggesting that customers are very aware that off-peak charging times begin at 9 p.m. They continue to charge during the off peak time until they stop charging between 6:00-8:00 a.m. This load shape appears to be somewhat the same regardless of season. Although not shown in the load profiles below, there is a lower demand between 10:00 p.m. and midnight during the weekend. This may be due to less customers charging on the weekends or a wider variety of charging times amongst customers, thus varying their charging times more.

Chart SCE – 8: TOU-EV-1 Average Load Profile



Average Peak Load for Separately Metered PEV Rates

Table SCE – 14 shows the distribution of the non-coincident peak demand. The average non-coincident peak (or average maximum demand) was approximately 4.7 kW for TOU-EV-1 customers. These peak demands are consistent with level 2 (240 volt) peak charging levels.

Table SCE – 14: Average Non-Coincident Peak Demand

TOU-EV-1: Average Non-Coincident Peak (kW/ Customer)	
Month	**kW**
Jun-11	5.11
Jul-11	4.94
Aug-11	4.95
Sep-11	5.02
Oct-11	4.67
Nov-11	4.68
Dec-11	4.64
Jan-12	4.58
Feb-12	4.54
Mar-12	4.49
Apr-12	4.47
May-12	4.38
Jun-12	4.43
Jul-12	4.38
Aug-12	4.67

Time of Diversified Peak Load for Separately Metered Rates

The time of diversified peak load gives the time that the group peaks as a whole (See Table SCE – 15). The average diversified peak would then be the average demand for each customer, when the group as a whole is peaking. TOU-EV-1 customers peak as a group between 10:00 p.m. – 1:00 a.m. (time of diversified peak load). This suggests that TOU-EV-1 customers are responsive to time of use periods and charge during off-peak times which begin at 9:00 p.m. Comparing these demands to the non-coincident peak demand in Table SCE-14, one might infer that on any given night, only a subset (perhaps about one in four) of customers is charging.

Table SCE – 15: TOU-EV-1 Time and Average Diversified Peak Load

TOU-EV-1: Time and Average Diversified Peak Load (kW/Customer)

Month	kW/Cust	Time
Jun-11	1.3	11:00 PM
Jul-11	1.2	11:00 PM
Aug-11	1.2	11:00 PM
Sep-11	1.3	11:00 PM
Oct-11	1.1	11:00 PM
Nov-11	1.1	10:00 PM
Dec-11	1.1	10:00 PM
Jan-12	1.1	10:00 PM
Feb-12	1.2	10:00 PM
Mar-12	1	1:00 AM
Apr-12	1	1:00 AM
May-12	1	1:00 AM
Jun-12	1.1	12:00 AM
Jul-12	1	11:00 PM
Aug-12	1.1	11:00 PM

Average Load Coincident with System Peak

The average load coincident with system peak is very small for TOU-EV-1 customers and fluctuates only slightly by month. Table SCE – 16 shows the distribution of the average load coincident with system peak.

Table SCE – 16: TOU-EV-1 - Average Load Coincident with System Peak

TOU-EV-1: Average Load Coincident with System Peak (kW/customer)

Month	kW
Jun-11	0.18
Jul-11	0.12
Aug-11	0.04
Sep-11	0.08
Oct-11	0.12
Nov-11	0.06
Dec-11	0.12
Jan-12	0.1
Feb-12	0.1
Mar-12	0.05
Apr-12	0.12
May-12	0.07
Jun-12	0.13
Jul-12	0.11
Aug-12	0.08

SDG&E

SDG&E offers residential customers two different rate options with respect to PEV. Currently, SDG&E does not have a commercial Electric Vehicle rate option.

SDG&E Whole House PEV Rates:

The EV-TOU-2 rate option is designed for residential customers that have their household load and their PEV load on the same meter. This is an optional rate and service under this schedule is specifically limited to customers (residential households) who require service for charging of a currently registered Motor Vehicle which is 1) a battery electric vehicle (BEV) or plug-in hybrid electric vehicle (PHEV) recharged via a recharging outlet a the customer's premises; or, 2) a natural gas vehicle (NGV) refueled via a home refueling appliance (HRA) at the customer's premises. On-peak is noon-6pm daily. The off peak period is 5am – 12 noon, and 6pm - 12 midnight daily, and the super off-peak is 12 midnight to 5am daily.

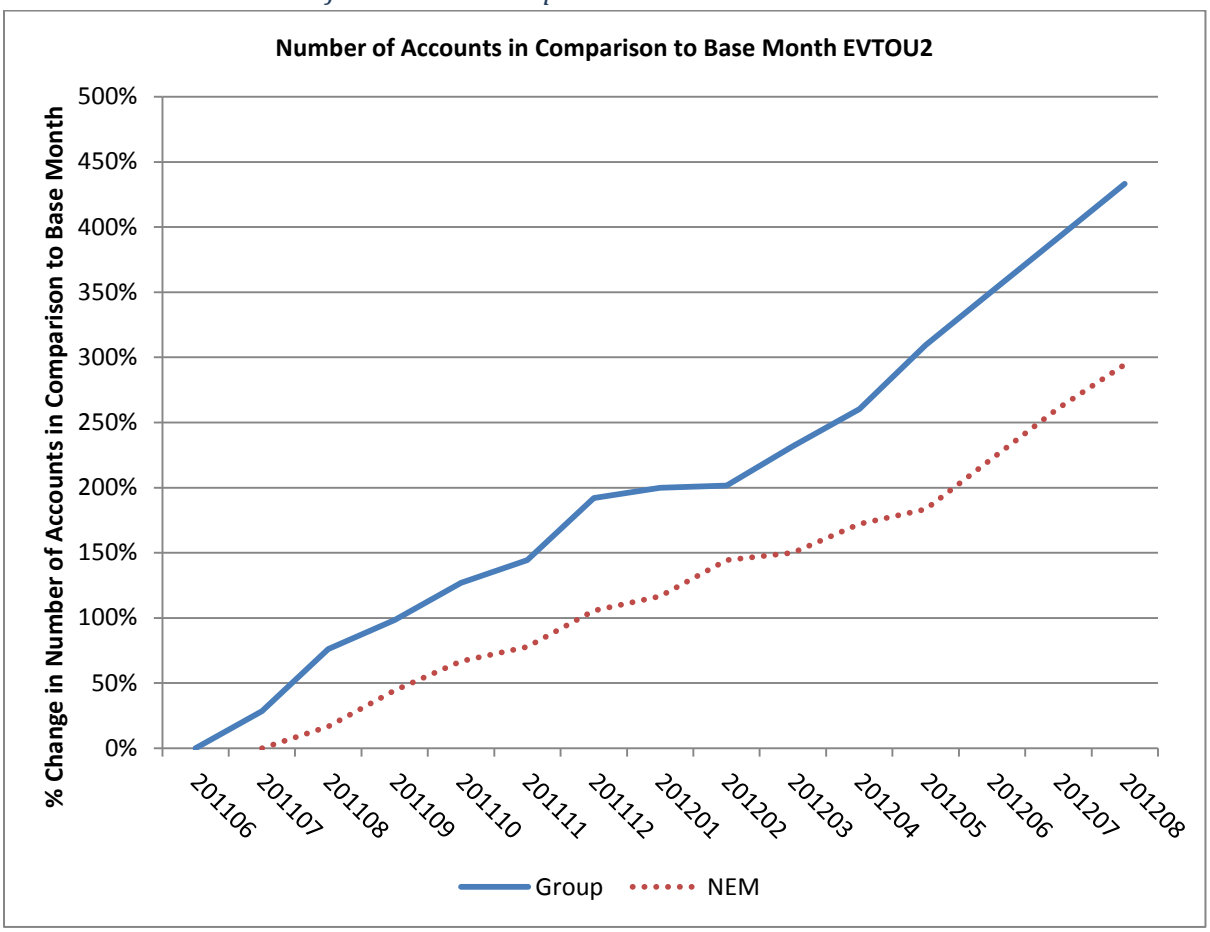
Please note that the current information drawn from those subgroups is very preliminary and it would be premature to make any judgments and/or policy decisions on sub groups or even the larger rate group, at this time. Additionally, SDG&E also cautions readers from drawing any major conclusions from any of the PEV rate information that has been provided over this past year. As can be seen from the

information presented in this document, the last 15 months of reporting for PEV rates in general is experiencing large rates of growth (800%) and the demand and energy data may not be stable enough to draw any major conclusions.

The current preliminary research presented herein analyzes usage patterns of early adopter customers whose characteristics and consumption patterns are often markedly different from the general population. One characteristic in particular is the possession of PV systems. Currently this group is over represented in the PEV rates class. The residential population in SDG&E's service territory consists of approximately 1.5% NEM customers, yet NEM comprises almost 25% of the PEV rates class. SDG&E believes that these customers tend to be more affluent with higher monthly consumption and also more energy conscious with a greater awareness and desire to modify usage behaviors when possible, than the average residential customer. As EVs become more popular it is not known what proportion of this group will also be NEM customers in the future.

SDG&E's EV-TOU-2 rate has experienced a large increase in customer growth over the 15 month load research reporting period (See Chart SDG&E – 1). In June of 2011 there were 63 customers on this rate, increasing to 336 customers in August of 2012. Currently, in December of 2012 there are now over 500 customers on EV-TOU-2. Additionally, the sub groups in EV-TOU-2 had too few customers to report on in June of 2011, and in August statistics were provided for the NEM and Demand Response subgroups as the number of customers had increased significantly. As more of the subgroup customers come onto EV-TOU-2 comparisons can be made

Chart SDG&E – 1: Number of Accounts in Comparison to Base Month EVTOU2



*Please note in the above graphic, for the EV-TOU-2 group the base month is 201106. However for the NEM Accounts the base month is 201107 as NEM accounts were not reported on in 201106, as noted above.

Consumption and demands for EV-TOU-2 are much higher than the typical residential customer on the default Schedule DR. Consumption is nearly twice as high as schedule DR, approximately 450 kWh to approximately 900 kWh respectively (See Charts SDG&E – 2 &3). Coincident peak loads are also twice as high as schedule DR as are diversified peak loads. The non-coincident peaks are almost double and they occur during the early morning hours.

Chart SDG&E – 2: Monthly Consumptions for EVTOU2 and Typical Residential Customers

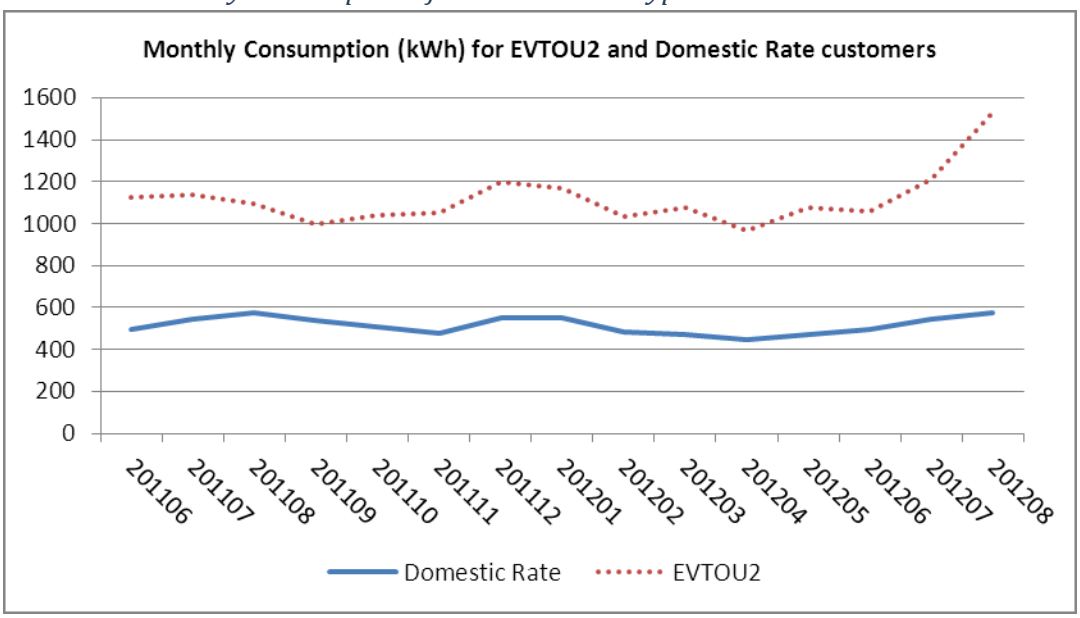
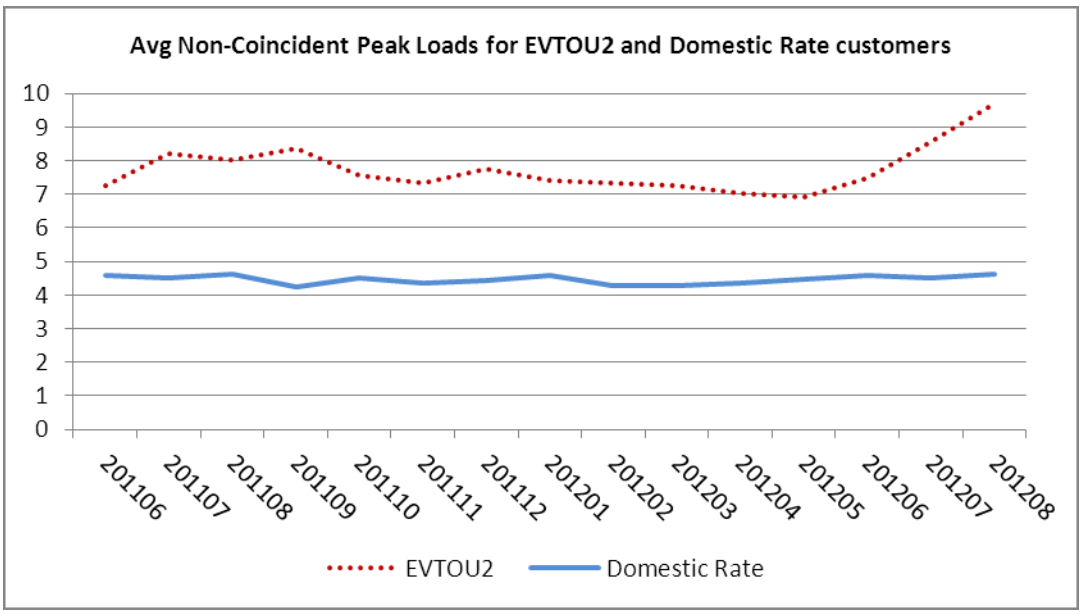


Chart SDG&E – 3: Average Diversified Peak Loads for EVTOU2 and Typical Residential Customers



The comparison of when EV-TOU-2 homes are peaking versus the typical residential rate (Schedule DR) is very enlightening. The customers on the EV-TOU-2 rate have price signals based on the TOU periods – which incentivize customers to use energy and/or charge their vehicles during the super off-peak period. In general, consumption patterns across TOU periods were fairly static for the duration of the study (See Tables SDG&E – 1 & 2). On-peak periods experienced approximately 28-33% of usage, off-peak was approximately 41-43%, and super off-peak was between 24-29% of total usage. EV-TOU-2 customers typically peak during the early morning hours 12:30am to 2:00am, whereas the typical residential customer peaks during the late afternoon to evening hours 3:45pm to 8:30pm.

Table SDG&E – 1: Diversified Peak for EV-TOU-2 and Residential Rate

Diversified Peak	EV-TOU-2		Residential Rate	
Month	Time	Avg kW	Time	Avg kW
201106	12:30 AM	2.85	3:45 PM	1.43
201107	1:30 AM	3.06	8:45 PM	1.11
201108	12:30 AM	2.88	8:30 PM	1.23
201109	8:30 PM	3.2	8:00 PM	1.36
201110	12:30 AM	3.06	7:15 PM	1.35
201111	1:30 AM	2.79	6:15 PM	1.10
201112	12:30 AM	2.89	6:30 PM	1.24
201201	1:30 AM	2.74	6:30 PM	1.19
201202	1:15 AM	2.92	7:30 PM	1.20
201203	1:15 AM	2.8	8:00 PM	1.07
201204	1:45 AM	2.64	8:15 PM	1.11
201205	1:15 AM	2.82	8:30 PM	1.26
201206	1:15 AM	2.95	3:45 PM	1.43
201207	1:15 AM	3.08	8:45 PM	1.11
201208	1:30 AM	2.45	8:30 PM	1.23

Table SDG&E – 2: Non-Coincident and Coincident Peak for EV-TOU-2 and Residential Rate

	EV-TOU-2 (kW)		**Residential Rate (kW)**	
Month	Non-coincident	Coincident	Non-coincident	Coincident
201106	7.26	1.2	4.57	1.27
201107	8.2	1.26	4.49	0.99
201108	8.03	1.27	4.62	1.10
201109	8.36	0.45	4.24	1.13
201110	7.56	1.42	4.49	1.20
201111	7.33	1.95	4.34	0.99
201112	7.76	2.27	4.44	1.26
201201	7.41	2.18	4.58	1.12
201202	7.32	2.26	4.28	1.09
201203	7.25	2.13	4.30	0.97
201204	7.04	1.96	4.34	0.89
201205	6.9	1.02	4.46	1.01
201206	7.48	1.24	4.57	1.27
201207	8.55	1.72	4.49	0.99
201208	9.72	2.29	4.62	1.10

SDG&E Separately Metered Electric Vehicle Rates

EV-TOU:

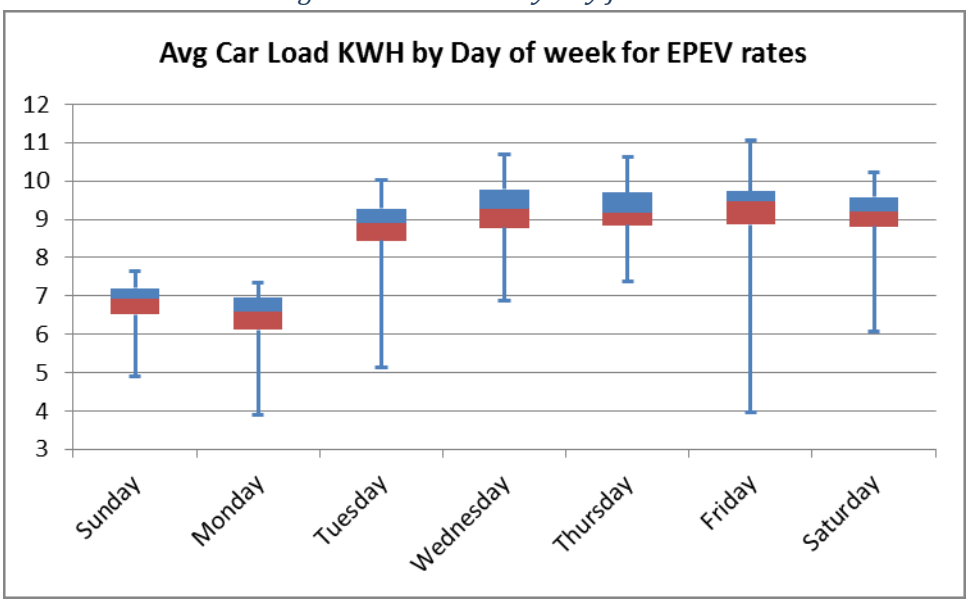
The EV-TOU rate option is designed for residential customers that have their PEV load on a dedicated meter. This is an optional rate to domestic service for charging of a currently registered Motor Vehicle which is 1) a battery electric vehicle (BEV) or plug-in hybrid electric vehicle(PHEV) recharged via a recharging outlet a the customer's premises; or, 2) a natural gas vehicle (NGV) refueled via a home refueling appliance (HRA) at the customer's premises. The point of service must contain facilities to separately meter PEV or CNG charging. On-peak is noon-8pm daily. There were only 3 customers on this rate when the load research reporting began, and only 10 were on the rate at the end of the reporting. This particular rate option is seeing growth if you look at the percentage increase, but the actual numbers are still quite small. The 15 customer threshold requirement in order to provide graphics was never met for this rate group.

EPEV-X, Y and Z:

This is an experimental bundled service schedule available to selected residential customers exclusively for charging a plug-in electric vehicle (PEV). The PEV must be a currently registered motor vehicle, as defined by the California motor vehicle code. This schedule is not available to customers with a conventional charge sustaining (battery recharged solely from the vehicle's on-board generator) hybrid electric vehicle (HEV). On-peak is noon-8pm daily. The ratio from on-peak to off-peak is 2 to 1, for EPEV-X, 4 to 1 for EPEV-Y and 6 to 1 for EPEV-Z. The off-peak time period is 5am - 12 noon, 8pm - 12 midnight daily, and the super off-peak is 12 midnight to 5am daily. These rate options with the different on peak to off-peak ratios were developed specifically for a pricing study and they will expire at the end of SDG&E's pricing study, which was recently extended for another year through 2013. Currently there are 415 EPEV customers. The study recruited Nissan LEAF customers and randomly assigned one of the three rate options to each customer as they joined the study. Each customer in the study received an EVSE (charger) with a timer as part of The EV Study funded by the DOE and CEC. This technology enabled customers to plug in the PEV at their convenience, yet charging would mostly occur during the super off-peak hours by utilizing the timer on the charger. Because the majority of charging was done in this manner, there was little variation in consumption patterns and charging behavior over the course of the study. Average monthly consumption was between 220 to 280 KWH and approx. 78-85% of consumption occurred during super off peak time period.

While SDG&E originally produced quarterly graphics relating weekend and weekday data, insights into EPEV consumption behavior produced by the EPEV pricing Experiment highlighted that overnight charging data reflected the distance driven in miles during the previous day. Thus the distinction in consumption is greatest between Sunday and Monday versus the rest of the week as illustrated in Chart SDG&E – 4.

Chart SDG&E – 4: Average Car Load kWH by Day for EPEV Rates



*Usage data is from 6/1/11 to 5/31/12

Using this information it is possible to show greater differences in charging behavior by separating the first two days of the week from the rest rather than traditional weekend versus week day. The charging behavior for Sundays and Mondays are the real "weekends" for PEV charging See Charts SDG&E – 5 & 6.

Chart SDG&E – 5: EPEV NEM Whole House Load for November 2012

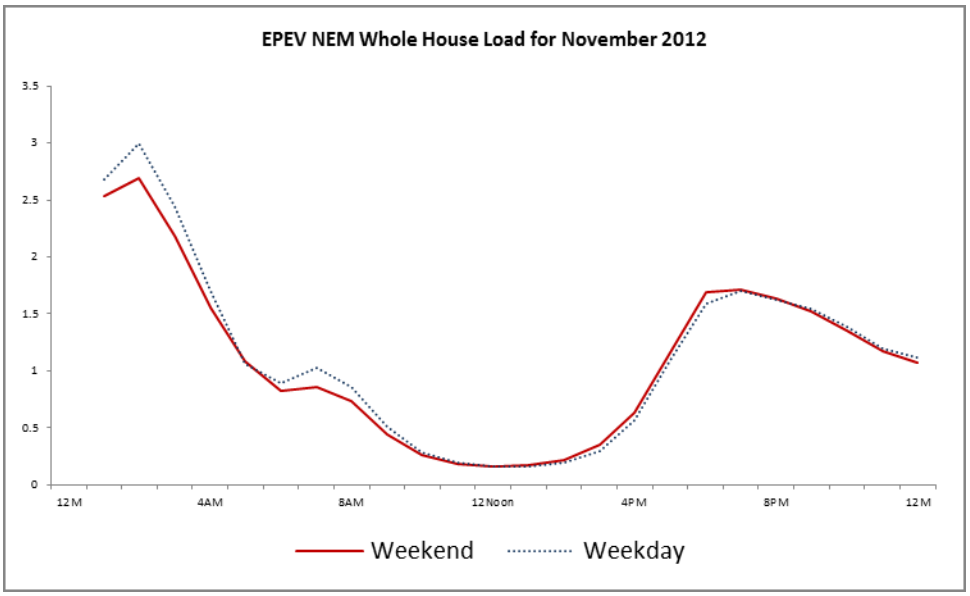
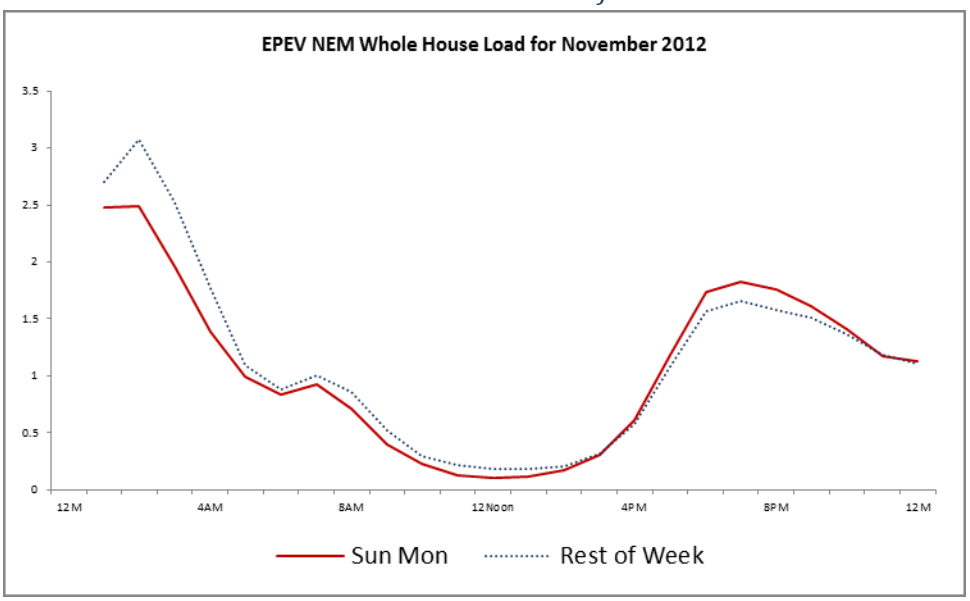


Chart SDG&E – 6: EPEV NEM Whole House Load for November 2012



Note that higher consumption on any given day does not correspond to higher individual demands – the charging capability during the study period maxed out at approx. 3.7kW however higher consumption does indicate longer charging times and higher average demands as a class. This will undoubtedly change and likely increase as the market continues to evolve with more powerful chargers and cars that have larger battery capacities.

Other questions attempted to be answered by the PEV Pricing Experiment relate to whether the EPEV rates act as effective deterrents to on-peak charging behavior. Chart SDG&E – 7 shows typical residential load shapes for customers that have PEVs as compared to the average population residential loadshape. This average population loadshape shows lower use than an average residential customer with a PEV – not on a time of use rate. The shapes are similar but the PEV home has higher usage. The EPEV load shape is a whole house load shape that includes the PEV charging load that is on a TOU rate (separately billed). Separating NEM and non NEM customers (See Chart SDG&E – 8), it is easy to verify that these rates coupled with the ease of a programmable timer for charging are very effective in shifting car charging patterns overnight as opposed to non-time based of use residential rates.

Chart SDG&E – 7: Non NEM Residential Whole House Load November 2012

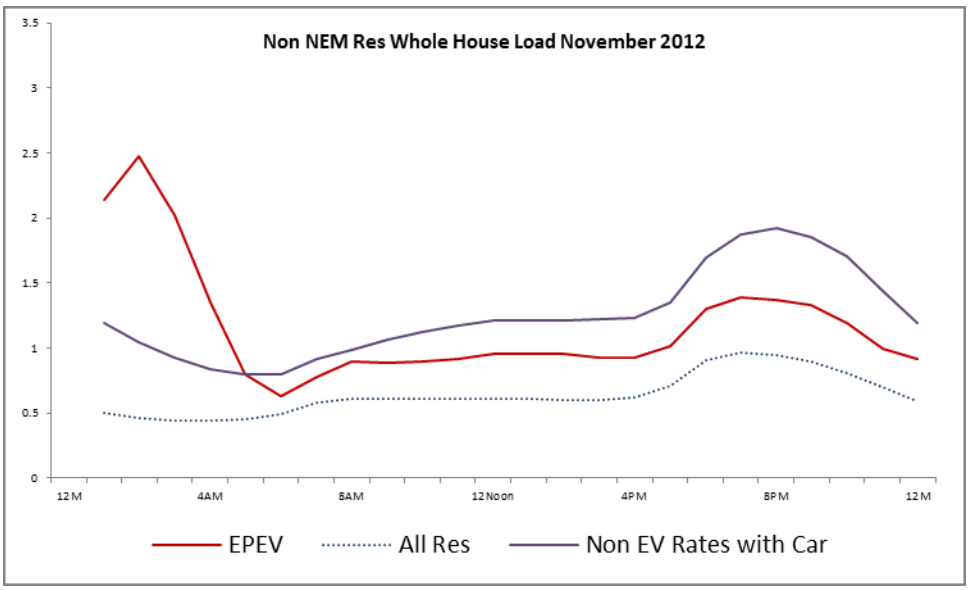
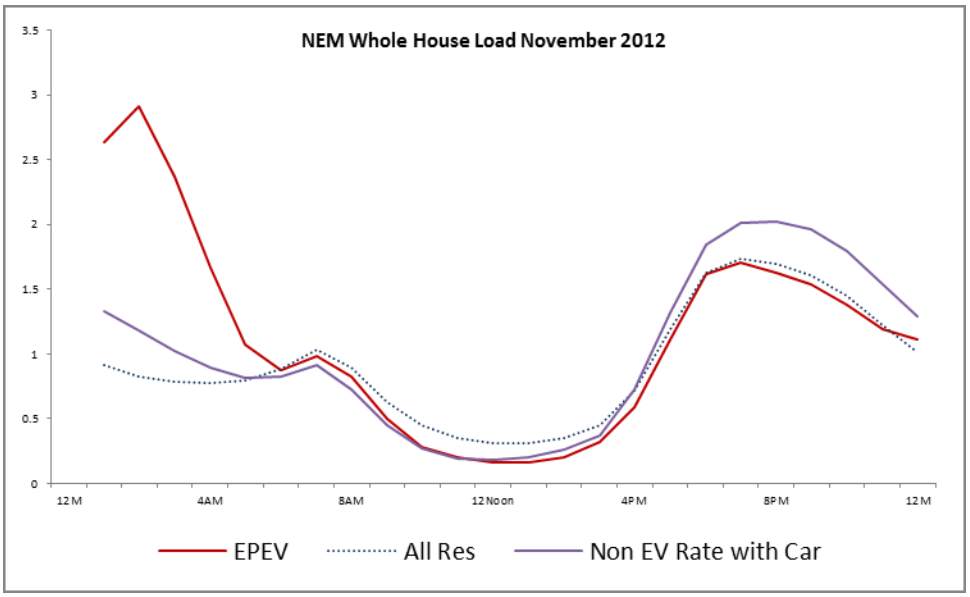


Chart SDG&E – 8: NEM Whole House Load November 2012



*Please note that non EPEV customers do not necessarily have EVSEs and thus may charge at lower kW, so the effects of charging may be less pronounced.

For more results on the EPEV rate and the PEV Pricing Experiment, please see the attached First Year Evaluation for San Diego Gas & Electric's Electric Vehicle Pilot (Dec 2012), which is attached to this report.

Conclusions and Observations

PG&E

- While the data collected is illustrative of the behaviors of early adopters of the types of first generation vehicles that are currently available in the market, one cannot conclude that these behavior patterns will hold as PEV technology matures, as charging requirements evolve, and as PEVs achieve greater market penetration thereby reaching different types of customers. Data that are sufficiently reliable for policymaking can only be obtained via an appropriately funded and carefully designed study that controls for the above issues.
- Consistent with what one should expect as a result of PEV ownership, there is sharp increase in the average PEV household usage as compared to the average PG&E residential customer. During the study period, non-NEM customers on E-9A used an average of 56% more energy than the full residential population (875 kWh per month versus 566 respectively).
- There is evidence that, amongst this group of early adopters and for this current composition of vehicles, customers on TOU PEV rates are charging during off-peak periods: E-9A customers use a lower percentage of energy in the on-peak period and a higher percentage in the off-peak period as compared to the residential population; E-9B customers do 77% of their PEV charging in the off-peak period and just 7% in the on-peak period; the diversified peak for customers on E-9A or E-9B occurs between 12am – 2am.
- On average, the PEV early adopters have a higher maximum demand that must be accommodated by the electric distribution system as compared to the average household without a PEV.
- Although the early adopter PEV customers may have a higher average maximum demand, those customers on the PEV rates tend to hit their maximum demand while non-PEV customers are at their lowest usage. Thus, there appears to be a diversity benefit created by the TOU rates. However, from the most local level service assessment level perspective (i.e. a single household or set of households serviced by a single transformer), the value of this diversity is limited by the fact that the distribution system must still be prepared to accommodate PEV charging during the peak period since these customers can, and occasionally do, charge during those times.
- All of the above conclusions are subject to change as the mix of customers and vehicles changes over time. During the study timeframe, the rapidly changing nature of PEV ownership was clearly evident in the changes that occurred in the mix of customers who own PEVs and types of the types of PEVs available. These changes will need to be considered in ratemaking and cost allocation policymaking. Therefore, California will need to continue to be flexible and adaptable with respect to PEV policies.
- PG&E proposed and received approval of an un-tiered TOU rate for customers with electric vehicles. While PG&E was ordered to file an un-tiered rate for its charging only option, the

Commission adopted PG&E's proposal for both its whole house and charging only PEV options. Specifically, the Commission said[33] :

> "Because of the Commission's stated desire to move away from tiered electric vehicle rates, we will approve PG&E's proposal to revise both its whole house and separately metered rates. A simple, easily understood rate could promote electric vehicle usage and more accurately reflect cost of service. Moreover, this rate may encourage electric vehicle adoption of high use customers, with off peak prices of less than $0.10/kWh compared with substantially more expensive upper tier rates on Schedules E-1 and E-9."

PG&E will be implementing its new PEV rates in 2013. The Commission directed the utilities to reevaluate their PEV rate design in their next rate design proceedings based on the conclusions in this report[34]. PG&E has done so and concluded that the results presented herein do not merit modification of the recently adopted but yet to be implemented PEV rates. This conclusion is primarily based upon two facts. First, the findings of this report are based upon a nascent market of first generation vehicles and early adopters that may not be representative of a mature PEV market. Second, the findings of this report are nevertheless consistent with the principles of PG&E's recently approved PEV rates.

SCE

- Caution should be applied when one is comparing the statistics from month to month or among groups since the customer mix has changed drastically from month to month during this study period. Although the statistics provided in this report demonstrate the behavior of early adopters, these statistics should not be considered as how the future PEV owners will behave with changing technology and hence should not be used in policy decisions.
- The number of PEV owners has been steadily increasing and increased almost five fold from the base month (June 2011) to the last month this report contains (August 2012).
- On average residential PEV owners that are on a TOU rate, are responding to the price variation as they charge more during super off peak hours. . Furthermore, the group peak time identical across months and across groups (i.e., the no distinction whether customers are single or multi family or if they on a demand response or a NEM customer).
- Load from electric vehicles represents approximately 30% of average household load.
- Despite general adherence to TOU time periods, SCE observes a staggering of charging time during weekends.

SDG&E

- Current Time-of-use (TOU) rates coupled with charging timers result in super off-peak PEV charging.

[33] Resolution E-4508, p.14.
[34] D.11-07-029, page 62

- Customers with PEVs that stay on SDG&E's typical residential non-TOU rate tend to show less usage during the super off peak period and increased usage during the afternoon-evening hours relative to those on PEV rates.
- Net-Energy-Metering (NEM) customers with PEVs respond to TOU rates.
- Demand and usage levels for these early PEV adopters are nearly double that of the average residential customer.
- Peak times for PEV Demands are typically in the early morning hours compared to evenings for typical residential customers.
- Sundays & Mondays have the lowest daily kWh consumed, for PEV customers on TOU rates.
- EV-TOU-2 (whole-house TOU rate) customer growth has increased about 800% over the past 15 months, which may cause instability in current Load Research results.

Next Steps

As ordered in D. 11-07-029[35] the IOUs have completed the required load research and filed this compliance report. The expected next step is for the Commission to schedule a workshop in early 2013 for all interested stakeholders to discuss the load research results. As further ordered in D.11-07-029[36] PGE will file a PEV rate design proposal in its 2014 General Rate Case and SDG&E and SCE will file PEV rate design proposals in Rate Design Window applications in 2013.

[35] See Ordering paragraphs 6 and 7.
[36] See Ordering paragraph 3.

Appendix A –: Other Research

SCE

SCE's Nissan Early Buyer Study

Background

In June 2012, SCE completed their Nissan Early Buyer Study.

- SCE has a new role as the electric fuel provider for customers with plug-in electric vehicles. In order to be optimally positioned as PEV adoption increases, SCE has established PEV Readiness Efforts.
- A significant component of SCE's PEV Readiness Efforts focuses on infrastructure planning for both in-home and away-from-home charging scenarios.
- Current infrastructure planning forecasts are based on assumptions made in early 2010. Since that time, several PEV models have been launched presenting SCE with the opportunity to examine early buyer behavior.

Research Objectives

The purpose of this research is to further inform SCE PEV Readiness Efforts planning by providing insight into the Nissan Leaf Early Buyer. Specifically:

- Travel and commute behavior
- Charging needs that support travel behavior
- The attitudes and motivations that underpin overall travel and charging behavior
- In particular, SCE sought to use the above information to better understand indicators of mass adoption for the PEV market

Method

- This study involved two primary components, a diary followed by an opinion survey.
- Respondents for this study were recruited from a list of LEAF owners supplied by Nissan.
- A 5-minute online interview was conducted from March 16 through March 21, 2012 to screen potential respondents. In order to participate in the study, respondents had to meet the following qualifications:
    - Owned their Nissan LEAF for one month or longer
    - Drive their Nissan LEAF 50% of the time or more compared to other household members
    - Use Southern California Edison (SCE) as their electricity provider
    - Were not planning on taking a vacation in late March or early April of 2012
    - Are at least 18 years of age
    - Do not work for a utility company, market research company, or auto manufacturer
- 213 invitations were sent for a target of approximately 100 respondents. Overall, 92 respondents completed both the diary and follow up survey.
- Each respondent recorded daily driving and charging behavior for a two week period between Match 25 and April 7, 2012. After the two week period of recording diary data, respondents

completed a 15-minute post-diary survey which they were able to access between April 7 and April 15, 2012. All information was collected online.

Key Finding

- Respondents are overwhelmingly satisfied with their Nissan LEAF vehicles, with 98% expressing some level of satisfaction and 83% indicating that they are very satisfied.
- Satisfaction with charging options, however, is noticeably lower. Although 64% of respondents are at least somewhat satisfied, only 14% are very satisfied and 27% express dissatisfaction.
    - Reasons for dissatisfaction with charging options center on the lack of availability of charging stations, particularly fast charging options.
        - Only 40% of respondents have charging available at their place of work.
        - 21% of respondents indicate that they have no charging option available outside of home or work.
        - 11% of respondents have no alternative to charging at home.
            - Thus, there is significant need for charging infrastructure expansion.
- When determining where to charge their LEAF, respondents are much more likely to make their decision based on convenience than on cost.
    - This prioritization of convenience over cost underscores the desire for more widely available charging options and could also represent opportunity in the pay for use charging space.
- On average, respondents charge their LEAF vehicles once per day. However, behavior in terms of daily number of charges shows considerable variation. Of particular note, respondents are much more likely not to charge their LEAF at all on weekend days compared to weekdays, likely a reflection of the LEAF's commuter car persona.
- Approximately three-quarters of all charges occur at home while only 16% of charges take place at work and 10% at other locations.
    - At any location, respondents most commonly charge their LEAF vehicles using a 240 volt charging station (82% of all charges).
    - Of the 26% of charges that take place away from home, the vast majority use free charging options (95%).
- Of all charges, the largest share (35%) takes place at home between 12:00am and 5:59am.

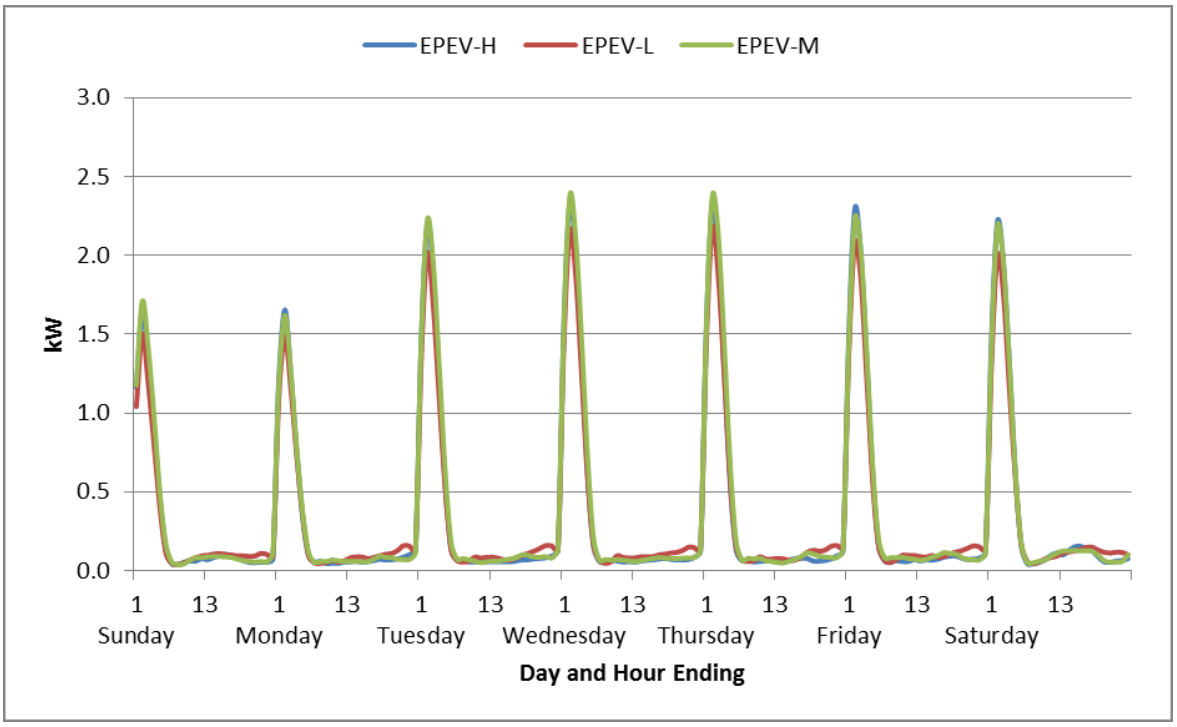
SDG&E – First Year Evaluation for San Diego Gas & Electric's Electric Vehicle Pilot (Dec 2012)

The attached report, summarized here, documents results from the first year of San Diego Gas & Electric Company's (SDG&E's) multi-year electric vehicle (EV) Rate Experiment. The results are preliminary and this progress report may not reflect results in the future final report. A final report on this experiment is expected in 2014, after 2013 results are analyzed.

The experiment uses an innovative research design based on a randomized pricing experiment to provide an early view of PEV owner response to time-varying rates for PEV charging. In the experiment, a group of SDG&E customers with EVs have been randomly assigned to one of three experimental time-of-use (TOU) rates specifically for their PEV charging.

The bottom line finding from the first year of this study is that TOU pricing rates in conjunction with a charging timer lead to the vast majority of PEV owners charging overnight rather than during peak times. Customers in the study use an average 8.3 kWh of home charging energy per day and roughly 80% of that has taken place during the super-off peak period of the study's time-varying rates. This value does not vary much across the rate groups within the experiment; with the lowest value of 78% occurring for the customers subject to the mildest time-varying rate (see Chart SDG&E – 9)

Chart SDG&E – 9: Average Daily EVSE Load, by Rate Schedule and Day of Week



The charging timer appears to make it so easy to charge overnight that even a quite mild rate differential induces a strong tendency for overnight charging. Greater detail about this and related findings are provided in the report, but this conclusion is promising to utilities faced with managing increased PEV ownership. Over the course of the second year of the study, it will be important to determine whether this pattern persists.

The report also includes an analysis of the relationship between customer charging patterns and self-reported data from the same customers on a survey completed in the winter of 2011-2012. The primary survey results were reported in an earlier project report. However, the analysis in the attached report is the first to link responses to observed load data. Two major findings emerge from the analysis: first, self-reported charging behavior is indicative of actual charging behavior; and second, there are no strong relationships between charging behavior and income, education or age (see Table SDG&E – 3).

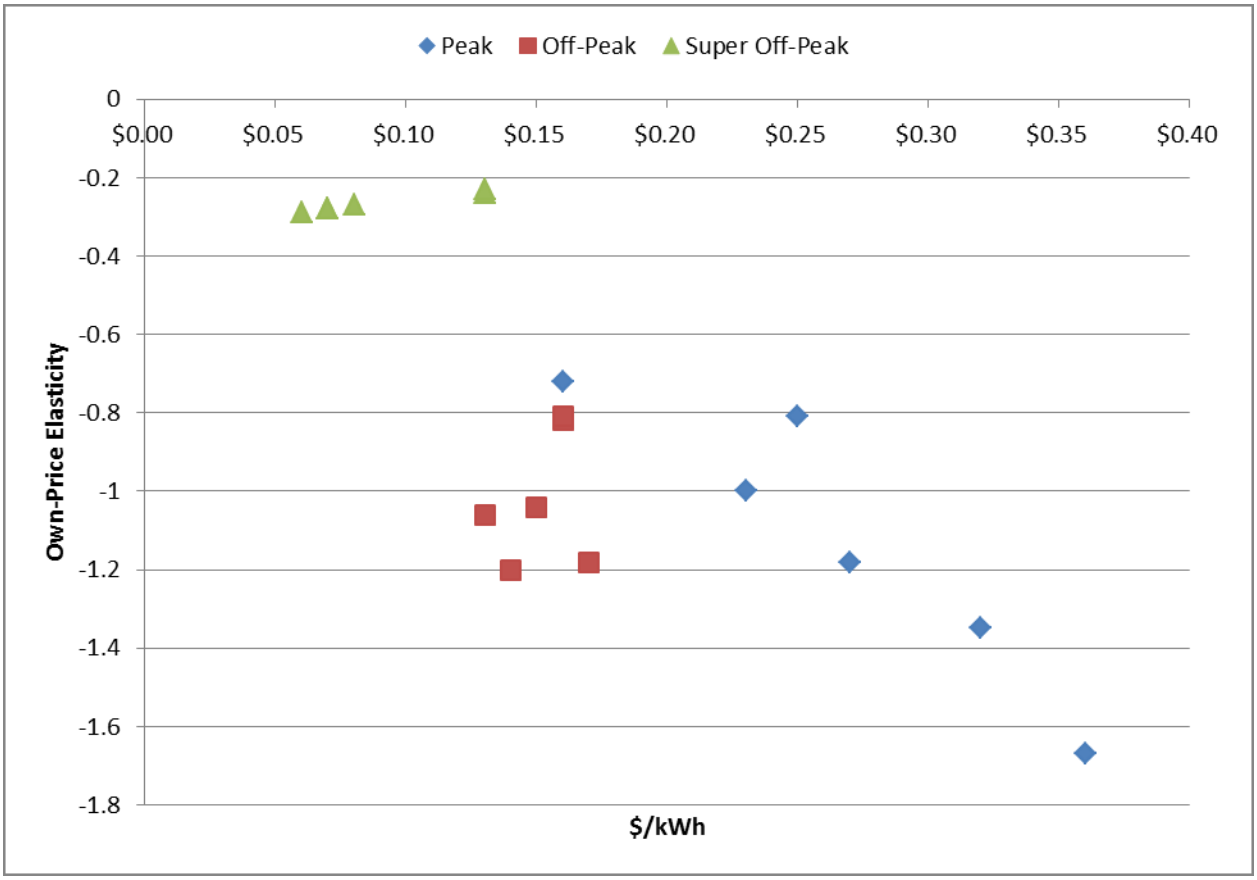
Table SDG&E – 3: Usage by Demographic Characteristics from Survey Participant Load Profiles

Demographic Characteristic	Avg. Daily Usage (kWh)	Maximum Demand on the Average Day (kW)	Number of Customers
Gender			
Male	7.89	2.20	78
Female	8.89	2.34	19
Decline to State	9.18	2.38	1
Age			
25 – 34	7.21	1.92	5
35 – 44	9.47	2.39	24
45 – 54	8.29	2.32	32
55 – 64	6.88	2.06	26
65 or Older	7.67	2.12	10
Decline to State	9.18	2.38	1
Education			
High School	8.41	2.37	1
Some College	7.95	2.08	5
Graduated College	8.10	2.23	43
Graduate School	8.08	2.24	48
Decline to State	9.18	2.38	1
Income (1,000 $'s)			
Less than 50	10.00	3.04	1
50 – 75	9.14	2.23	4
75 – 100	7.69	2.04	8
100 – 125	7.80	2.15	8
125 – 150	8.39	2.39	15
150 – 175	8.12	2.38	13
175 – 200	9.46	2.32	3
More than 200	8.46	2.35	19
Decline to State	7.50	2.02	27

Finally, the report includes an economic demand model of charging behavior, fitted to the observed charging data. In order to apply findings from this study to other charging prices that might be considered for the future or for other jurisdictions, we estimated a model of the economic trade-offs that a customer faces when choosing to charge at one time as opposed to another. The model, known as a generalized Leontief model, is a standard way of accounting for these trade-offs. The main conclusion from this model is that customers appear to be more responsive to on-peak prices when

price ratios are higher. The model is also used to predict usage levels under alternative price schedules not included in the experiment; those results are shown in the body of the report (see Chart SDG&E – 10).

Charts SDG&E – 10: Elasticity Results Versus Prices During Each TOU Period



The attached report documents results from the first year of San Diego Gas & Electric Company's (SDG&E's) multi-year electric vehicle (EV) Rate Experiment. These results are preliminary and this progress report may not reflect results in the future final report. A final report on this experiment is expected in 2014, after 2013 results are analyzed.

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First Year Evaluation for San Diego Gas & Electric's Electric Vehicle Pilot

December 21, 2012

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1 Executive Summary

This report documents results from the first year of San Diego Gas & Electric Company's (SDG&E's) multi-year electric vehicle (EV) Rate Experiment. These results are preliminary and this progress report may not reflect results in the future final report. A final report on this experiment is expected after 2013 results are analyzed.

This experiment uses an innovative research design based on a randomized pricing experiment to provide an early view of EV owner response to time-varying rates for EV charging. In this experiment, a group of SDG&E customers with EVs have been randomly assigned to one of three experimental time-of-use (TOU) rates specifically for their EV charging. The timing of EV charging has major implications for a utility's ability to preserve reliability of the distribution system as EV penetration increases in its service territory. If EVs are charged at peak times, then each one added to a neighborhood is about the equivalent of an additional household worth of load added to that neighborhood.[1] This could require distribution upgrades, as well as additional stress on distribution equipment. On the other hand, if EV owners can be induced to charge during off-peak times, then the stress and risk on the distribution system will be much less.

The bottom line finding from the first year of this study is that TOU pricing rates in conjunction with a charging timer lead to the vast majority of EV owners charging overnight rather than during peak times. Customers in the study use an average 8.3 kWh of home charging energy per day and roughly 80% of that has taken place during the super-off peak period of the study's time-varying rates. This value does not vary much across the rate groups within the experiment, with the lowest value of 78% occurring for the customers subject to the mildest time-varying rate. The charging timer appears to make it so easy to charge overnight that even a quite mild rate differential induces a strong tendency for overnight charging. Greater detail about this and related findings are provided in this report, but this conclusion is promising to utilities faced with managing increased EV ownership. Over the course of the second year of the study, it will be important to determine whether this pattern persists.

This report also includes an analysis of the relationship between customer charging patterns and self-reported data from the same customers on a survey completed in the winter of 2011-2012. The primary survey results were reported in an earlier project report.[2] However, the analysis reported here is the first to link responses to observed load data. Two major findings emerge from this analysis: first, self-reported charging behavior is indicative of actual charging behavior; and second, there are no strong relationships between charging behavior and income, education or age.

Finally, this report includes an economic demand model of charging behavior, fitted to the observed charging data.[3] In order to apply findings from this study to other charging prices that might be

[1] Typical peak EV charging load for a given household in this study is 2-2.5 kW. Households in SDG&E's territory typically have peak summer time loads of 1-2 kW. This value varies depending on many factors, such as the presence of central air-conditioning.

[2] See "Interim Report for San Diego Gas & Electric's Electric Vehicle Pilot," prepared by Freeman, Sullivan & Co. for SDG&E.

[3] The analyses in this report focus on the charging behavior of customers who opted to be a part of the pricing experiment by being assigned to one of three experimental charging rates. There is also a group of customers who have chosen not to be on one of those rates, but who are still part of the broader study and whose whole-house load data is of interest for this study. An analysis of those customers' charging behavior was documented in the interim report mentioned above and

considered for the future or for other jurisdictions, we estimated a model of the economic trade-offs that a customer faces when choosing to charge at one time as opposed to another. The model used here, known as a generalized Leontief model, is a standard way of accounting for these trade-offs. The main conclusion from this model is that customers appear to be more responsive to on-peak prices when price ratios are higher. The model is also used to predict usage levels under alternative price schedules not included in the experiment; those results are shown in the body of the report.

another such analysis will be included in the second year report on this project. This report does not contain any analysis of charging behavior of customers not on one of the three experimental TOU rates.

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2 Introduction

In April 2010, SDG&E began recruiting customers for a multi-year EV rate experiment taking place from early 2011 to mid 2013. This experiment is designed to investigate several areas of customer behavior related to EV usage and charging. San Diego is 1 of 18 major cities selected by the EV Project as a test site for evaluating plug-in electric vehicles (PEVs).[4] Nissan plans to sell 1,000 LEAF PEVs[5] in San Diego. These vehicles are battery electric vehicles, not plug-in hybrid electric vehicles.

As part of the EV Project, all customers purchasing a LEAF were offered no-cost electric vehicle supply equipment (EVSE) for home installation (approximate value $1,499), up to $1,200 credit towards the installation of the equipment and a DC Fast Charge port on the car at no charge (approximate value $700).[6] The EVSE is then installed at the EV owner's home and provides power at 240 Volts at 30 Amps as compared to 120 V at 12 A from an EV Cord Set in a standard wall outlet; higher voltage allows for faster vehicle charging than can be accomplished through a standard wall outlet. Charging the LEAF at 120 V adds approximately 5 miles of range per hour of charging, while 240 V charging adds approximately 12 miles of range per hour of charging (depending on driving style and driving speed). A full charge of the LEAF takes up to 20 hours from an EV Cord Set and up to 7 hours from the EVSE, depending on the EV's state of charge at the beginning of the charging session. The EVSE, installed on a dedicated branch circuit of the home's electric distribution system, also allows for a separate meter to be installed for measuring the electric consumption due to EV charging.

The installation cost for EVSE ranges from about $600 to several thousand dollars, depending on the configuration of the customer's home and on the electrical complexity of the installation. In many cases, the $1,200 credit offered by ECOtality for installation covers the entire cost of the installation. The customer is obligated to pay for any installation costs above $1,200.

The goals of the SDG&E's rate experiment are to understand the potential impact of EV technology on the electric utility infrastructure and identify methods to mitigate grid impacts. The FSC Group (FSC), in this report, provides estimates of the impact of EV technology and three different EV-specific TOU rates on the energy consumption of pattern of participating customers approximately one year after most customers received their vehicle and charger. FSC's analysis uses electricity usage data for the EVSE (obtained from a dedicated utility billing meter), surveys of participant customers and demographic information to answer a number of important questions, including:

- What are the impacts of the various TOU rates on charging behavior?
- How is charging behavior affected by the availability of EVSE timers?
- Do charging patterns change over time as customers become more familiar with the technology?
- How does charging behavior vary across different demographic segments?

[4] The EV Project is funded by DOE and the California Energy Commission, and managed by ECOtality. See www.theevproject.com for more details.

[5] All vehicles in the SDG&E rate experiment are PEVs (all electric Plug-in Electric Vehicles); however, for simplicity we refer to these vehicles as EVs in this report.

[6] This equipment and installation subsidy is provided by ECOtality and funded partially by DOE and partially by shareholders of ECOtality.

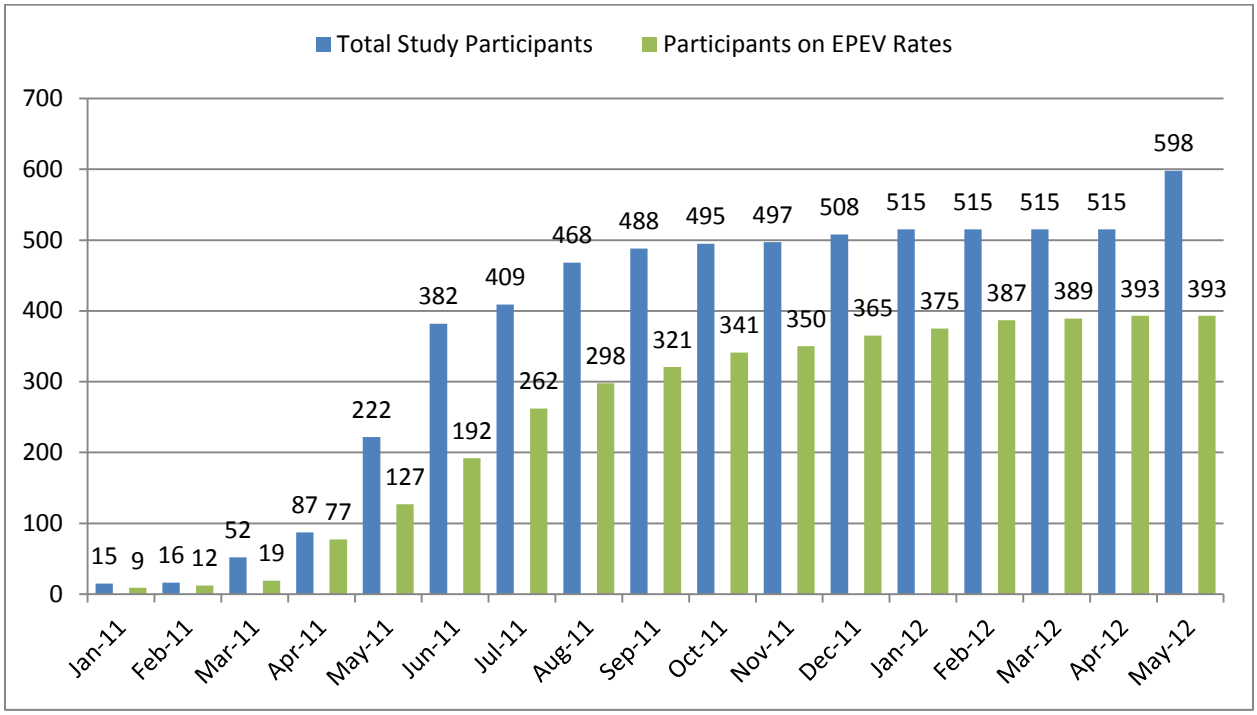
The rate experiment tested three TOU rates, each of which has three periods: peak, off-peak and super off-peak. Customers who chose to be part of the rate experiment are randomly assigned to one of the three TOU rates for the duration of the study. The rates apply only to load from the EVSE and not to the customer's entire house load. There are different prices for charging at different time periods during the day (referred to as "on-peak," "off-peak" and "super off-peak"). The on-peak period runs from noon to 8 PM, the off-peak period runs from 8 PM to midnight and 5 AM to noon, and the super off-peak period runs from midnight to 5 AM. These TOU periods do not vary by day of week and make no exceptions for holidays. The three rates are designed to test low, medium and high price ratios, between the super off-peak to on-peak prices. In addition, there are different price ratios between the three rates in the on-peak to off-peak price and between summer and winter seasons.

The EVSE and EV come with a timers that allows customers to set the time of day at which charging will begin. This technology may have a strong impact on the charging behavior of EVSE users, by making it easier for them to charge during a preferred time.

As of May 2012, 598 EVs in the SDG&E service territory were participating in the pilot, and 393 of them had been assigned to 1 of the 3 experimental EV rates. Figure 2-1 presents EV study enrollment over time, including both customers on experimental rates and all customers in the study, and Figure 2-2 presents active participants by location.[7] The number of enrollments showed an initial acceleration, followed by a leveling off in late 2011. Study participants are spread throughout the service territory, with the highest number in Carmel Valley (ZIP code 92130).

[7] Not included in the charts are 48 participants who dropped out of the study; there are no start or stop dates associated with these participants.

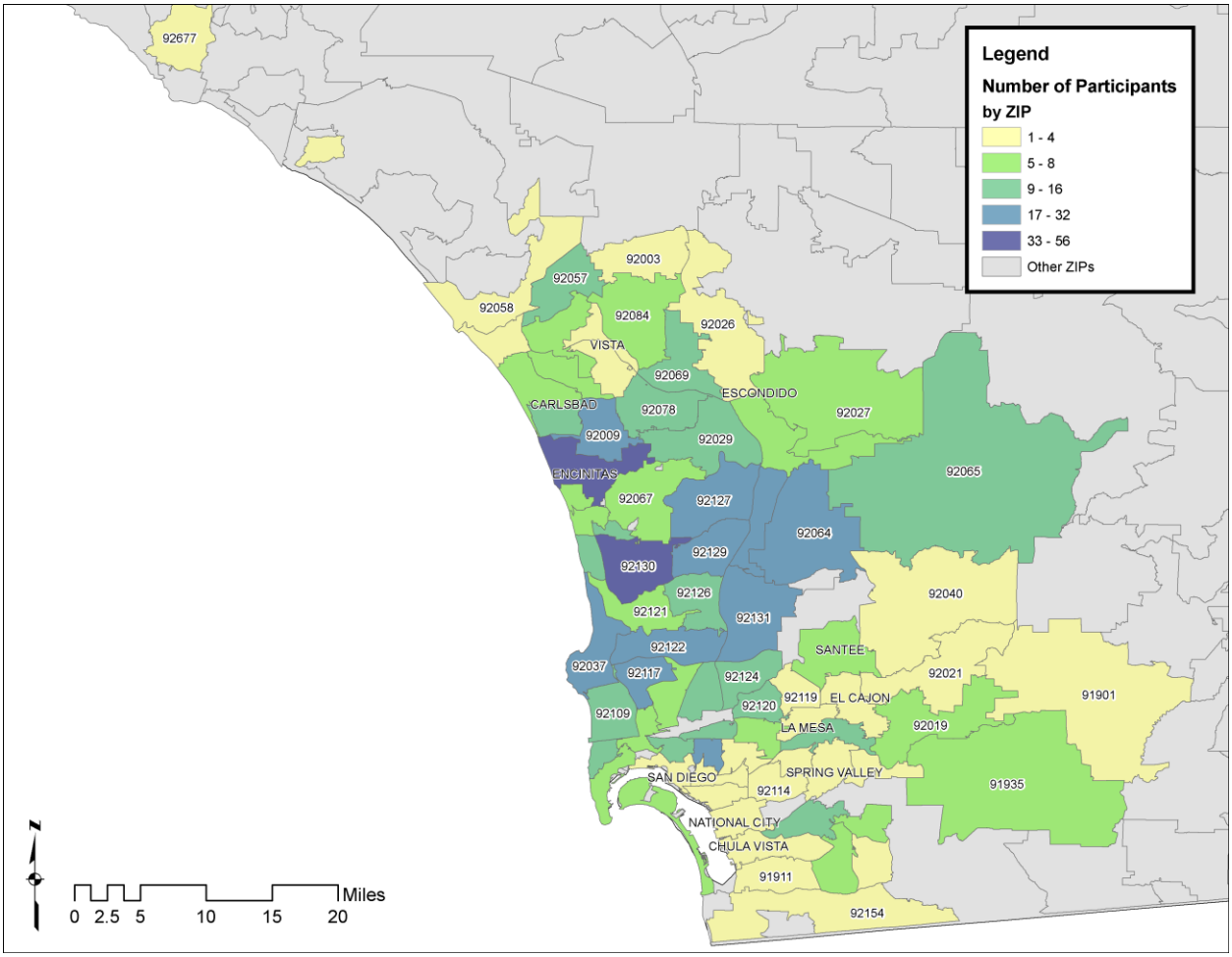
Figure 2-1: Cumulative Number of Study Participants[8,9]



[8] These numbers are obtained from estimated EV delivery dates. Specific delivery dates for those received after January 2012 are not available.

[9] Note that there is a gap in enrollment date information, which leads to the flat enrollment in the study from January to May 2012.

Figure 2-2: Active Study Participants by ZIP Code



Those customers who accept the EVSE offer from the EV Project, and whose residences are compatible with EVSE installation, are also offered the opportunity to take part in the SDG&E rate experiment. In this experiment, customers with an EVSE may elect to be randomly assigned to one of three experimental TOU rates for EV charging use. The experimental rates require a dedicated meter used for billing that captures the EVSE load. The second meter installation is typically performed during the same time as the EVSE installation. SDG&E paid the cost of the equipment necessary for the second meter, which includes the dedicated meter, a meter socket box and an electrical disconnect switch.

There are two options for customers who take part in the EV Project, but who do not elect to be assigned an experimental rate. First, SDG&E currently offers an electric vehicle TOU rate (Schedule EV-TOU-2) that applies to the entire load of a customer's home (whole house). This rate schedule also has three rate periods but has an on-peak period that runs from noon to 6 PM rather than noon to 8 PM. The rate's TOU period definitions also do not vary by day of week. However, the EV-TOU-2 on-peak period moves to off-peak status on holidays. Second, customers may continue to have all their usage, including EV charging, billed on their current rate, which for most participants is the standard

residential rate, Schedule DR.[10] Schedule DR is an usage based increasing block rate, undifferentiated over time. EV Project customers are not required to participate in the rate experiment in order to receive an EVSE as part of the EV Project.

2.1 Participant Characteristics

Table 2-1 lists details of the experimental rate schedules of participants in the rate experiment. Participants who opted in to the rate experiment were randomly assigned to an EV charger-specific experimental rate schedule (EPEV-L, EPEV-M or EPEV-H). The rates are named EPEV-X, EPEV-Y and EPEV-Z in the SDG&E tariff book. We use the suffixes L, M and H to make it clear which rates have stronger price ratios or signals. The low price ratio is designated L, while the high price ratio is designated H; M designates a price ratio in between the L and H rates. Table 2-1 includes the non-experimental whole house EV-TOU-2 rate for comparison purposes.

Early in the experiment, participants were randomly assigned to one of two rate schedules (EPEV-H or EPEV-M); after a few months, a third rate schedule (EPEV-L) was added to the recruitment scheme. EPEV-L has price ratios similar to the EV-TOU-2 rate. Use of the third rate schedule allows for a better understanding of customers' demand for charging load at different times of the day. Also, independent sources of variation in two of the three TOU periods will allow for a fully-identified demand model of charging behavior.

Table 2-1: Rate Schedules of Study Participants[11]
Total Rates Effective July 1, 2012

Period		EV-TOU-2		EPEV-L		EPEV-M		EPEV-H	
		$/kWh	Ratio to Super Off-peak	$/kWh	Ratio to Super Off-peak	$/kWh	Ratio to Super Off-peak	$/kWh	Ratio to Super Off-peak
Summer	Peak	$0.24	186%	$0.25	202%	$0.27	383%	$0.36	571%
	Off-peak	$0.15	117%	$0.16	123%	$0.17	241%	$0.14	228%
	Super Off-peak	$0.13		$0.13		$0.07		$0.06	
Winter	Peak	$0.16	122%	$0.17	124%	$0.23	303%	$0.32	483%
	Off-peak	$0.15	117%	$0.16	119%	$0.15	202%	$0.13	193%
	Super Off-peak	$0.13		$0.13		$0.08		$0.07	

The three experimental rate schedules differ by the ratio of on-peak to super off-peak rates. EPEV-L has the lowest ratio, offering participants fairly mild incentives to charge during the super off-peak period. During the summer, the on-peak rate ($0.25/kWh) is just under two times the super off-peak

[10] See Figure 2-1 for details on the fraction of customers choosing EPEV rates versus other rate options.

[11] These Rate Schedules represent the total bundled rates include the Utility Distribution Company (UDC) total, and the Department of Water Resources Bond Charge (DWR-BC) and Electric Energy Commodity Charge (EECC) rates. The experimental rates are actually named EPEV-X, EPEV-Y and EPEV-Z in the SDG&E tariff book. We use the suffixes L, M, and H to make it clear which rates have stronger price signals. Prices are rounded to two decimal places to simplify presentation in Table 2-1.

rate ($0.13/kWh). During the winter, the on-peak rate ($0.17/kWh) is 24% higher than the super-off-peak rate ($0.13/kWh).

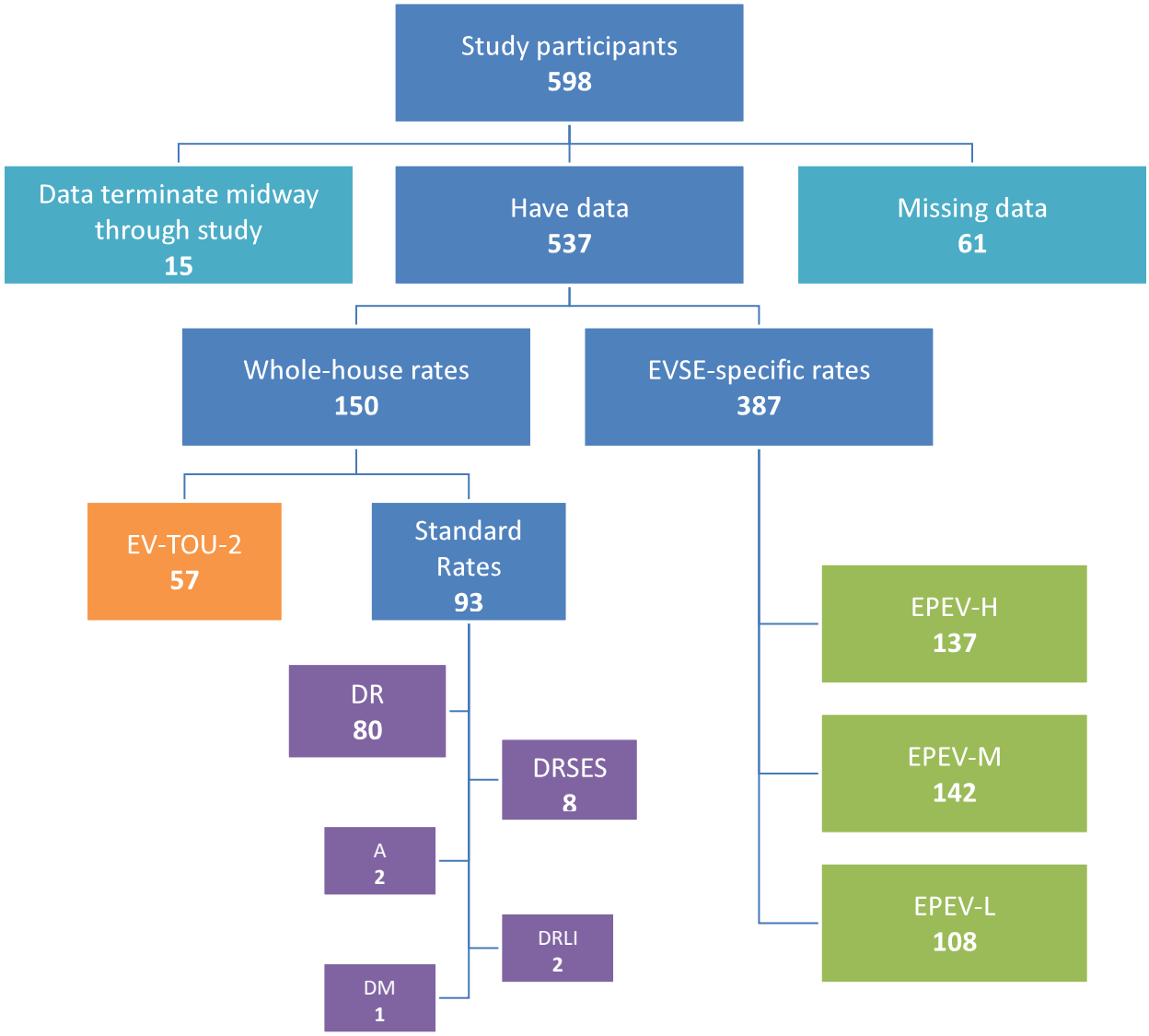
EPEV-M has a larger price ratio. During the summer, the on-peak rate ($0.27/kWh) is just under four times the super off-peak rate ($0.07). During the winter, the on-peak rate ($0.23/kWh) is almost three times the super off-peak rate ($0.08/kWh).

EPEV-H has the largest price ratio and is intended to provide the largest incentive for super off-peak charging. During the summer, the on-peak rate ($0.36/kWh) is six times the super off-peak rate ($0.06/kWh). During the winter the on-peak rate ($0.32/kWh) is nearly five times the super off-peak rate ($0.07/kWh).

The three rates also differ in their ratios of on-peak to off-peak prices, as shown in Table 2-1. Here again, EPEV-L provides the mildest price differentials and EPEV-H provides the strongest on-peak to super off-peak ratio. In general, the price ratios are lowest for EPEV-L, and increase for EPEV-M and EPEV-H.

Figure 2-3 presents the number of study participants for whom interval data is available as of May 30, 2012, by rate schedule. Of participants for whom interval data is available, 150 do not have a separate EVSE rate schedule. Of these customers, 57 have opted for the EV-TOU-2 rate and 93 currently remain on standard (i.e., non-EV) rates. Most customers on standard rates elect the DR rate schedule.

Figure 2-3: Number of Customers with Interval Data, by Rate Schedule
As of May 30, 2012



Another important customer characteristic is the presence of a solar photovoltaic (PV) system. PV systems are present in 204 (38%) of participant households who have interval data, as shown in Table 2-2. This is an important issue because these customers face quite different incentives regarding their charging behavior. Specifically, they may be more apt to charge their vehicles during the day using the energy from their PV system, which they would otherwise get a credit for providing to the grid. Table 2-2 shows the distribution of customers over rates and whether or not they have PV. Virtually all customers who opt-out of the EV rates have PV systems (94%), but the converse is not true; there is a substantial group of customers who have PV systems and are on an EV rate. The fact that almost all EV customers on non-TOU standard rates have PV systems suggests that EV customers with PV systems make systematically different decisions about rates, most likely to maximize economic benefits from their PV systems. Additionally, in this population, behavior of customers not on EV rates is driven almost completely by customers with PV.

Table 2-2: Customers with Household PV, by Rate

Rate Schedule		Have PV system	No PV system	% have PV system
EV Rate	EPEV-H	35	102	26
	EPEV-M	36	106	25
	EPEV-L	27	81	25
	EV-TOU-2	22	35	39
Total on an EV Rate		120	324	27
Standard Rate (no EV rate)	DR	76	4	95
	DR-LI	2	0	100
	DR-SES	8	0	100
	DM	1	0	100
	A	0	2	0
Total not on an EV Rate		87	6	94
Total on PV		207	330	39

It is reasonable to assume that this population of PEV drivers and owners is probably similar to near-future PEV drivers and owners. This study does not attempt to generalize its findings beyond this population of PEV consumers.

The remainder of this report is organized into four sections and two appendices. Section 3 presents several analyses of interval load data associated with EV chargers and premises of the study participants. Section 4 discusses the results of a survey of pilot participants that was performed in December 2011 in light of the charging behavior observed for the same participants. Section 5 presents the findings of the econometric analysis of an EV charger demand model. Section 6 concludes with major findings and a discussion of future analyses that may become feasible. The appendices contain further details about the demand model.

3 Analysis of Charging Behavior

This section presents statistical analyses of load data and examines important patterns in the data. There is also further analysis of load data done to support the demand modeling in Section 5.

Figure 3-1 presents average weekday EVSE loads for the period August 2011 to June 2012. In general, EVs in the study begin charging immediately after midnight. Loads gradually decline through the night until 6 AM, at which point most EVs have ceased charging and do not charge again until the following night. The slight increase in loads after 11 PM suggests some customers initiate charging prior to midnight. Customers on rates EPEV-H and EPEV-M appear to have nearly identical average EVSE loads, whereas customers on EPEV-L rates have lower average loads after midnight and slightly higher average loads in the evening hours prior to midnight. The total level of charging usage is similar across the three groups. Figure 3-1 is centered at midnight rather than noon to show the peak period more clearly.

Figure 3-1: Average Weekday EVSE Load, by Rate Schedule

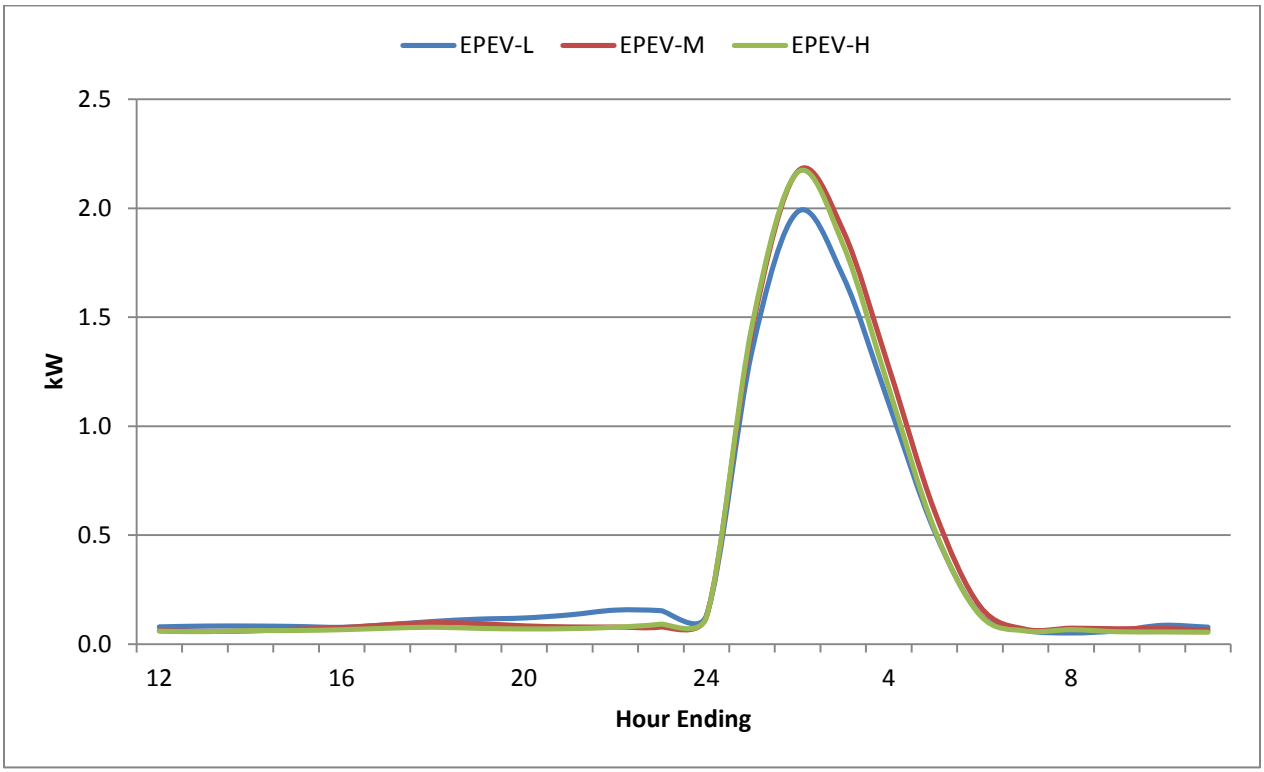


Figure 3-2 shows the same analysis as Figure 3-1, but calculated over weekends rather than weekdays. The basic pattern of charging is almost identical, with lower overall loads.

Figure 3-2: Average Weekend EVSE Load, by Rate Schedule

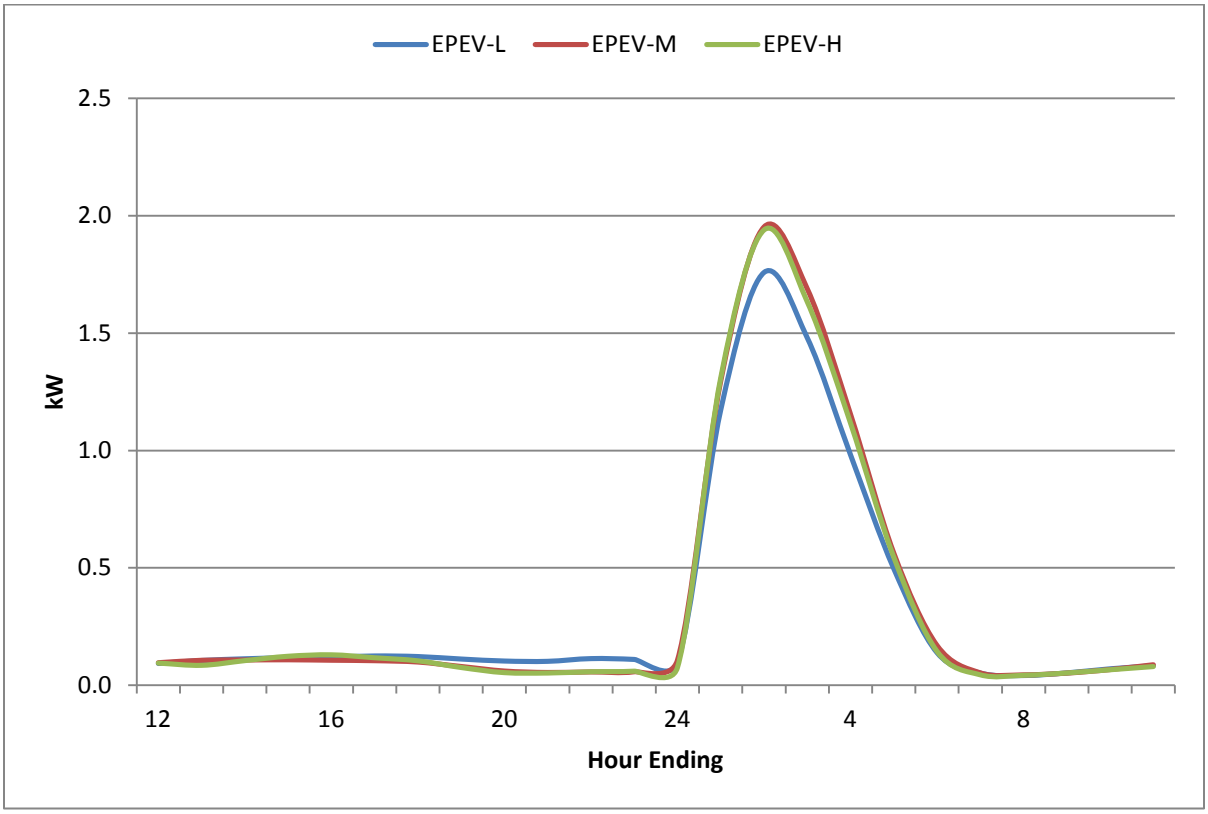


Figure 3-3 shows the same analysis as Figures 3-1 and 3-2, but calculated over individual days of the week separately. The basic pattern of charging is the same over each of the days, but loads are lower on Sundays and Mondays, which probably reflects lower usage of the EV on weekends than on weekdays.

Figure 3-3: Average Daily EVSE Load, by Rate Schedule and Day of Week

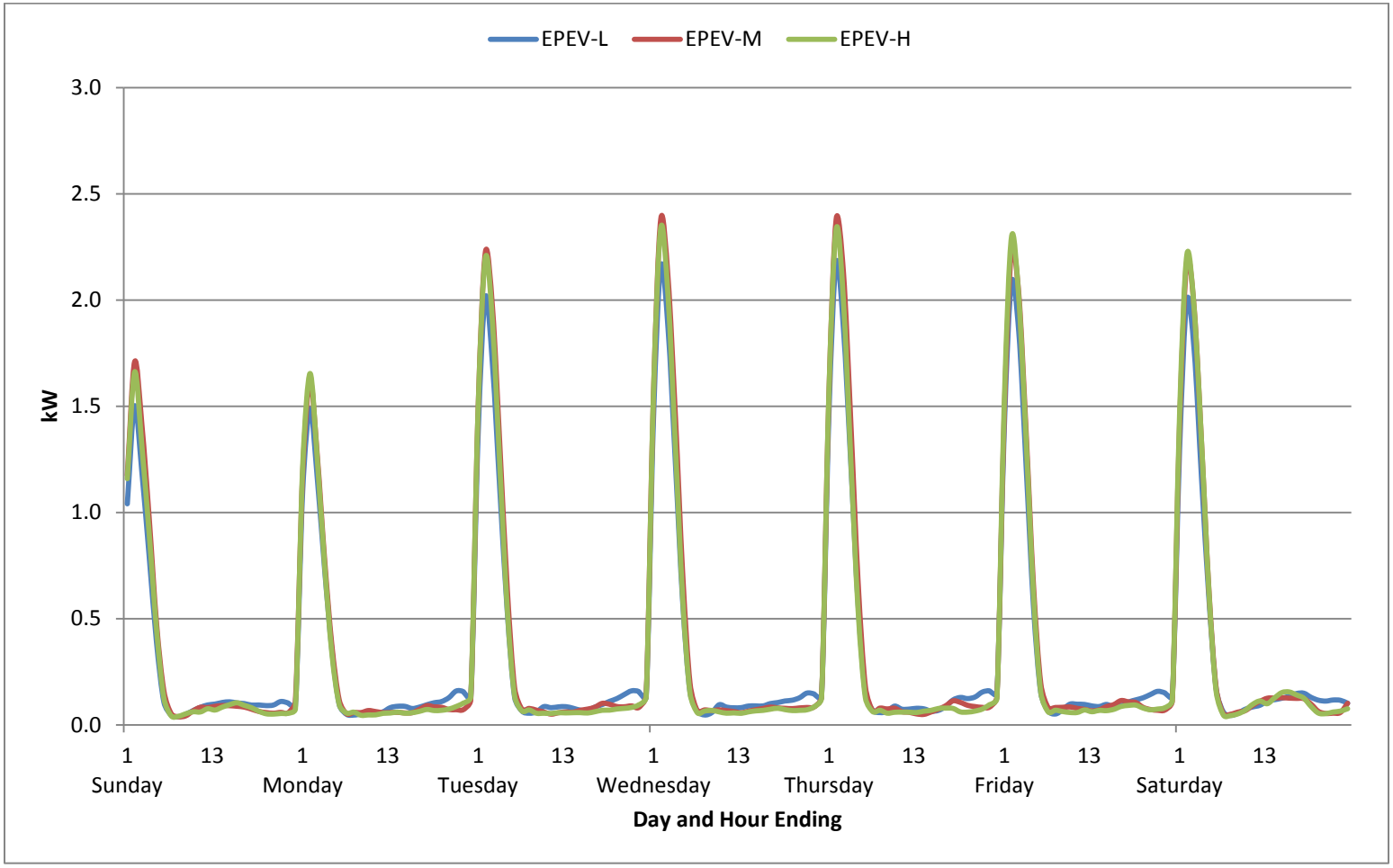


Figure 3-4 presents the average proportion of daily EVSE loads by rate period for all days in which charging activity occurs.[12] For EPEV-H and EPEV-M customers, 84% and 83% of charging activity occurs during super off-peak hours, respectively. For EPEV-L customers, 78% of charging occurs during super off-peak hours. As shown in Table 5-5 below, the differences in the amount of super off-peak charging between the customers on EPEV-L and the other two rates are statistically significant. This suggests that the lower rates faced by the EPEV-L customers outside of the super off-peak periods makes them more likely to charge during the peak and off-peak hours.

Figure 3-4: Average Proportion of Daily EVSE Energy Consumption by Rate Period

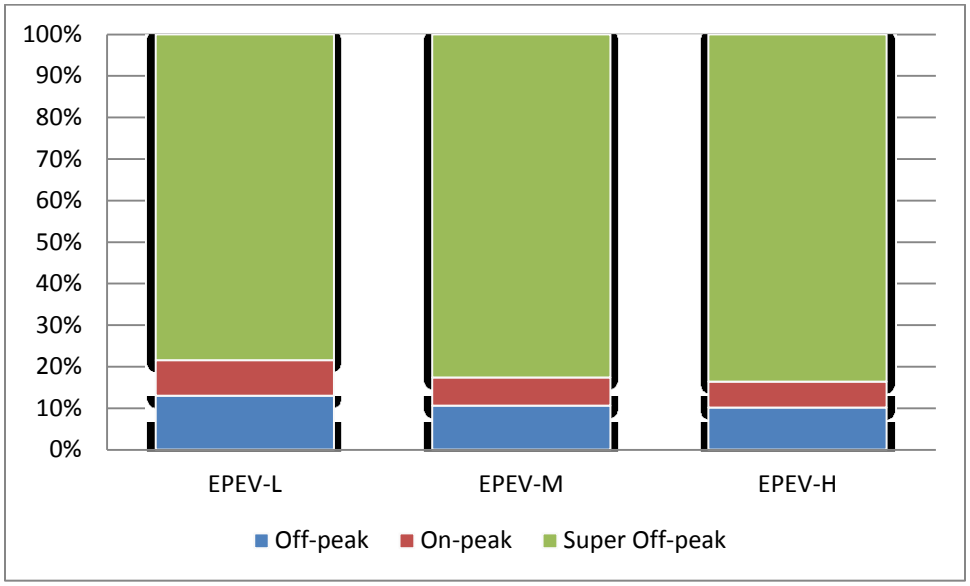


Figure 3-5 presents the average super off-peak proportion of daily EVSE loads by month. While average proportions fluctuate month-to-month, due to a mix of natural variation and new participants joining the study, on average EPEV-L customers persist at slightly lower levels of super off-peak charging.

Figure 3-5 also shows some evidence that customers on different rates are trending toward their expected relative super off-peak consumption over the course of time. For example, customers on the TOU rate with the weakest peak price signal (EPEV-L) have seen the greatest decline in super off-peak's share of usage. At the same time, customers on the TOU rate with the strongest price signal (EPEV-H) have seen the greatest increase in super off-peak share of usage. This may indicate customers are learning about their rates and adapting their behavior; whether this is true or not will become clearer over the next year as additional data is collected for this study.

[12] We exclude all observations where total EVSE consumption over the course of the day is less than 1 kWh.

Figure 3-5: Average Super-off Peak Proportion of Daily EVSE Energy Consumption, by Month

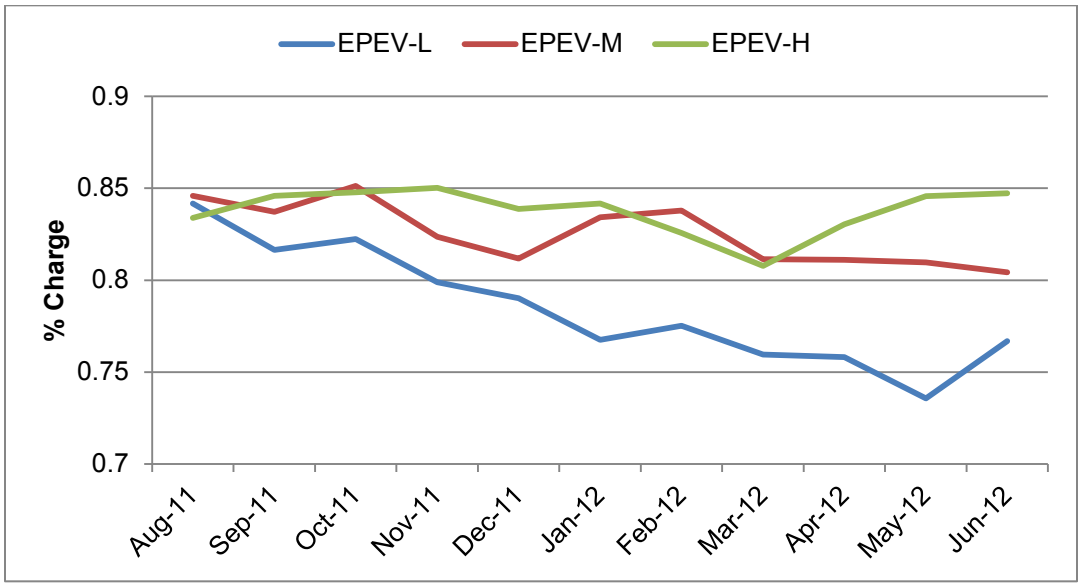


Figure 3-6 presents the average super off-peak proportion of daily EVSE loads by the number of months after the first charging session. This figure is meant to address the problem that Figure 3-5 mixes customers of different tenures in the experiment. Similar to Figure 3-5, Figure 3-6 shows that EPEV-L customers persist at slightly lower levels of super off-peak pricing while customers on the steeper TOU rates increase their super off-peak share of usage.

Figure 3-6: Average Super-Off Peak Proportion of Daily EVSE Energy Consumption, by Months on Rate

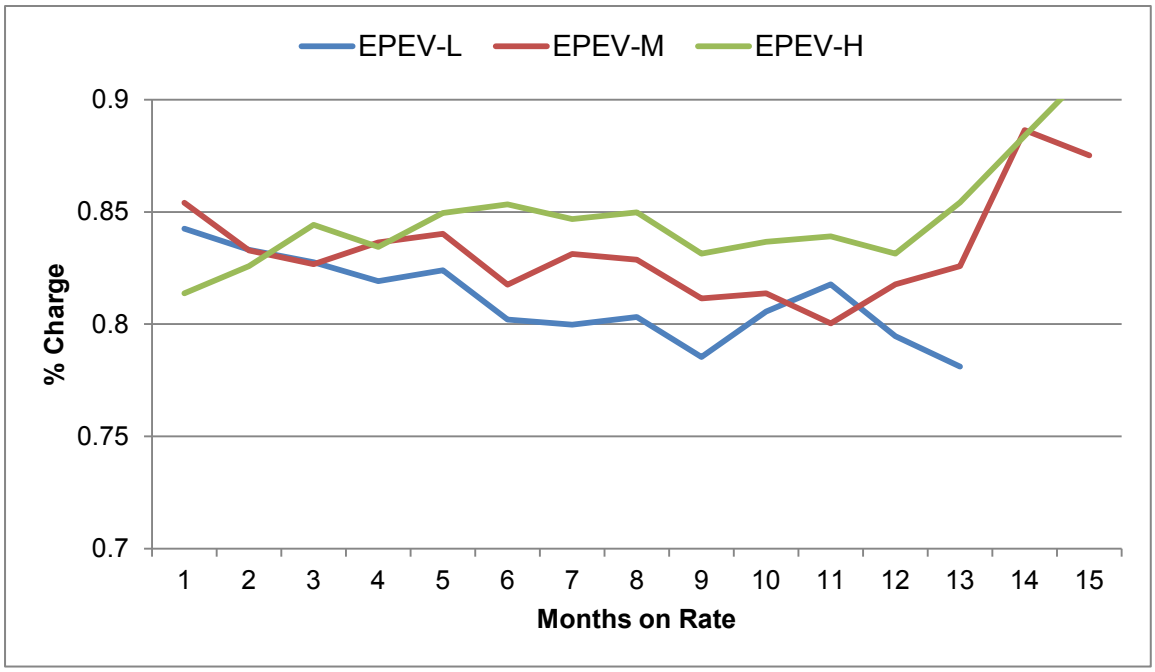


Figure 3-7 presents the median monthly kWh consumption by months after the first charging session. There is no clear trend in any of the values, with all values remaining fairly close to 250 kWh per month throughout the study. Note that not all customers have data available for the full duration of this graph, which means that in Figure 3-7 as "months on rate" increases from left to right, the number of customers observed on the rate in the data decreases.

Figure 3-7: Median Monthly EVSE Energy Consumption, by Months on Rate

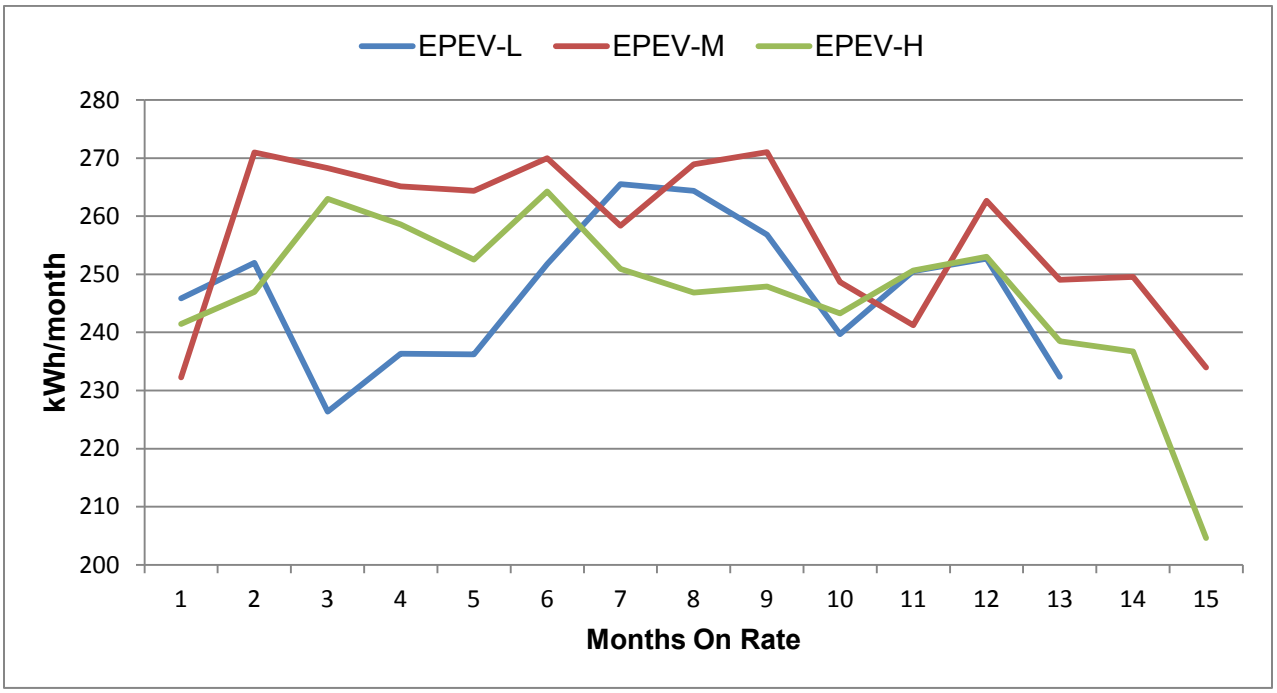


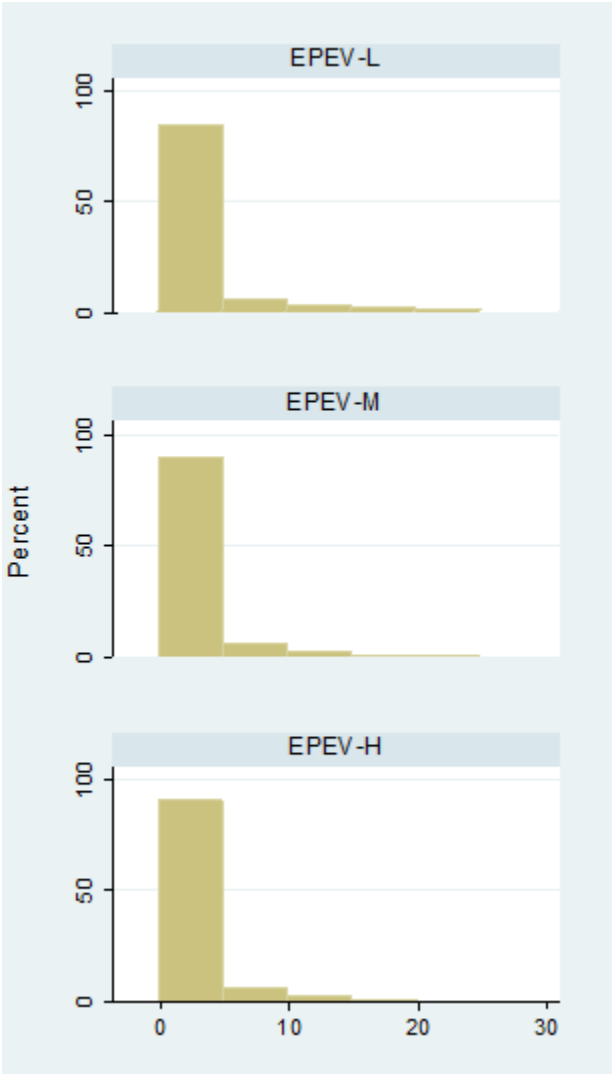
Figure 3-8 addresses whether the differences in super off-peak charging across rates are due to the actions of most customers or just a few customers. The figure presents the distribution across customers of the average number of weekdays per month that 50% or more of EVSE power consumption occurs outside of the super off-peak period.[13] The fact that the bar to the left is the highest on each graph is a consequence of the high amount of super off-peak charging overall.

A notable aspect of Figure 3-8 is that the right tail of the histogram for EPEV-L customers is thicker than for the other two rates. This is because customers are more willing to charge away from the super off-peak period in that group than in the other two groups. However, the difference between the three graphs is mainly due to the behavior of three customers in the EPEV-L group. These three customers' behavior may not be related to the EPEV-L rate, and may instead reflect random characteristics that happened to show up three times among customers on one of the rates. For example, it might be the case that there are few customers on the EPEV-L rate who work away from home late at night, and therefore charge more outside of the super off-peak period. On the other hand, if we had found that the average load shape differences in Figure 3-1 were the result of the small differences in many members of the group, it would be more likely that the observed differences

[13] Days are excluded where total EVSE consumption is less than 1 kWh.

in usage were the result in behavioral changes caused by the TOU rate. However, with the difference due to such a small number of customers, it is impossible to discern whether the average differences in usage are motivated by differences in TOU pricing, or instead result from random variation in the customer population.

Figure 3-8: Distribution Across Customers of the Average Days per Month with a Majority of Charging Outside of Super Off-peak, by Rate Schedule[14]



FSC analyzed EV charger consumption data at 15-minute increments to generate summary information about charging events. For any period in which consumption was greater than 0.1 kWh, the interval was considered part of a charging event. A set of consecutive charging intervals comprises one charging event. Charging events separated by a single 15-minute increment of non-charging were consolidated into one charging event.

[14] The x-axis on the EPEV-H graph is the same axis as on the EPEV-M and EPEV-L graph.

Table 3-1 presents the duration of EVSE charging events. The average charging event lasts approximately two hours and forty-five minutes. Eighty percent of charging events were less than four hours.

Table 3-1: Duration of EVSE Charging Events

Charge Duration	% of Charging Events
0 to 1 hr	19%
1 to 2 hrs	19%
2 to 3 hrs	22%
3 to 4 hrs	20%
4 to 5 hrs	14%
5 to 6 hrs	4%
6+ hrs	1%

Overall, the statistical analysis of charging behavior continues to show a strong tendency for super off-peak charging. This indicates that customers are substituting electricity usage in other periods to the super off-peak period in response to the incentives of all of the TOU rates. Furthermore, customers on the TOU rate with the weakest price signal (EPEV-L) are charging more outside of the super off-peak period when compared to the customers on the TOU rates with stronger price signals (EPEV-M and EPEV-H). This is evidence that the degree to which customers respond to the TOU rate depends on the price signal strength (peak to off-peak ratio) of the rate.

There is also some evidence that customer behavior is changing over time. Customers on EPEV-L have seen the largest decrease in the super off-peak usage over time. In addition, customers on EPEV-H have seen the biggest increase in the super off-peak usage over time. This might indicate that customers learn more about their rates over time, and are behaving more like we would expect in the long run. Another possibility is that customers with weaker TOU rates are becoming relatively less reliant on the use of the EVSE or EV charging timer over time. If true, it would probably lead to more charging outside of the super off-peak period. Currently, these differences between the charging patterns of customers on the different rates are due to the actions of a small number of participants, and it will be important to observe whether these differences persist over time.

4 Linking Charging Behavior to Survey Responses

This section presents findings on survey responses associated with charging behavior. In November 2011, SDG&E invited participants in the rate experiment to participate in a survey of customer knowledge, behavior and attitudes related to EV use and charging.

Approximately 476 participants were sent mail or email invitations. Approximately 121 participants were not sent invitations due to their stated desire to opt-out of SDG&E related survey or marketing activities. Participants completed the survey by following a URL link to a survey website hosted by Vision Critical. A unique participant code was used to link a participant's survey responses with their usage data. Follow-up invitations were sent approximately one week after the initial invitation, as a reminder.

There were 205 customers who responded to the survey and the interim report extensively documented responses to the survey.[15] Since that analysis took place, however, FSC can now link survey responses to EVSE charging and whole-house load data. Out of the 205 survey participants, 156 of them can be linked to whole-house load data and 102 can be linked to EVSE charging data. A few analyses are provided below that further examine survey results in light of this new link. These analyses corroborate the results of the survey, indicating that survey responses are consistent with metered load data.

Figure 4-1 shows the average daily load profiles for three groups of customers, divided according to their self-reported percentage of home charging activity. For example, the red line in the graph corresponds to the 50 survey participants who reported engaging in 95% or more of their charging while at home. According to the interval data, participants who indicate that they do most of their charging while at home in their survey responses have greater average daily usage than participants who indicate that they charge at charging stations away from home in their survey responses.

[15] See "Interim Report for San Diego Gas & Electric's Electric Vehicle Pilot" prepared for SDG&E by The FSC Group.

Figure 4-1: Average Survey Participant Load Profiles by Reported Percent of Charging Activity at Home

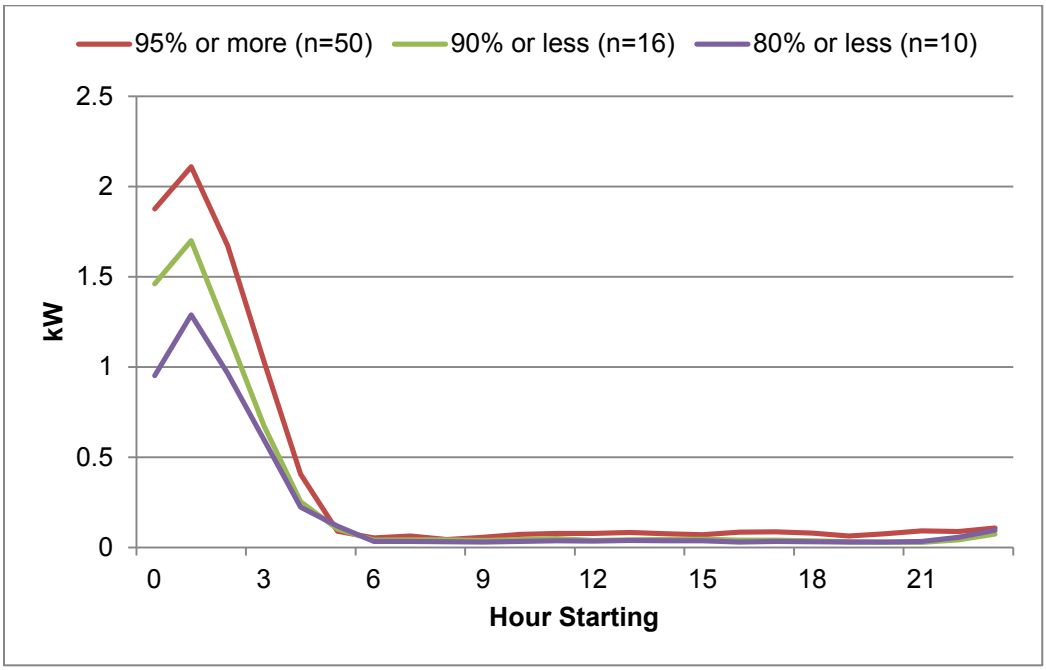


Table 4-1 shows average demand categorized by the percentage of home charging activity and TOU period. The basic pattern shown in Figure 4-1 arises here as well. Customers with lower proportions of at-home charging have lower levels of off-peak and peak charging as well as super off-peak charging.

Table 4-1: Average Survey Participant TOU Period Demand (kW) by Percent of Charging Activity at Home

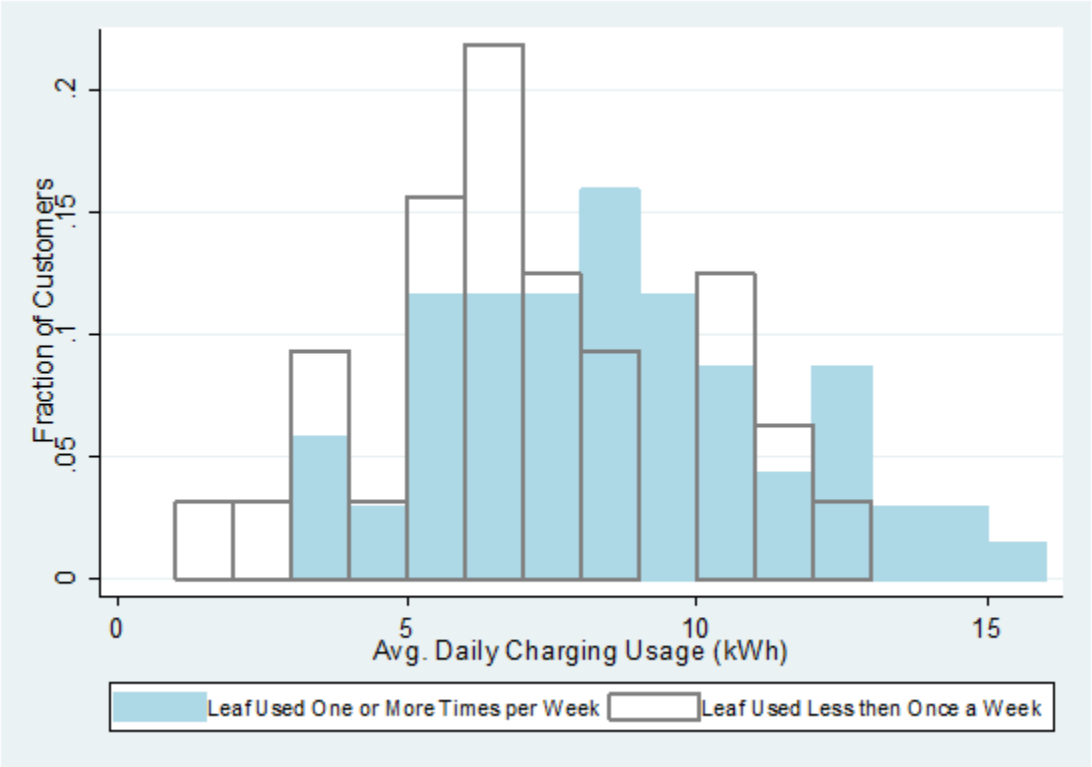
TOU Period	95% or more	90% or less	80% or less
Super Off Peak	1.42	1.06	0.80
Off Peak	0.08	0.05	0.05
Peak	0.08	0.04	0.03

One of the survey questions asked participants to indicate if they use the timer on their EVSE or EV. The customers who used the timer were asked the start and end times during which they set the timer. FSC examined the interval data of the 89 survey participants who indicated that they used the timer to determine if most of their charging activity took place during the time period set by the participants. Based on EVSE charging data, these respondents engage in 86% of their total charging during the time periods they indicated on the survey, indicating both that these respondents responded accurately and that they do the vast majority of their charging with the timer.

Another survey question asked participants how often they used the LEAF for driving to work or school, short trips around town, vacations, long trips, business or work use. FSC categorized participants into two groups – those who stated they use the LEAF more than once per week and

those who stated they use it less than once per week, averaged across all activities. Figure 4-2 is a histogram of the average daily usage of participants across both of these categories. As expected, the distribution of usage of participants who use the LEAF less than once per week is centered left of the distribution of usage of participants who use it more than once per week. This shows that the more frequent users of the LEAF also charge more frequently, as expected, and it further corroborates the results of the survey. The average daily charging usage for customers who use the LEAF one or more times per week is 8.27 kWh, while the average daily charging usage for customers who use the LEAF less than once per week is 6.93 kWh. These values correspond to the mean values of the distributions shown in Figure 4-2.

Figure 4-2: Distribution of Avg. Daily Survey Participant Charging Usage By Customers Who Use the LEAF More than Once a Week (n=69) and Customers Who Use it Less than Once a Week (n=32)



Based on these three results, participants in the study generally behaved as they indicated with their survey responses. This is a useful finding since it is rare that we have the opportunity to corroborate survey responses with independently measured data on respondents.

The survey also asked participants for several demographic characteristics. Table 4-2 shows average daily usage and maximum demand on the average day for participants by various demographics. Maximum demand on the average day is determined by first taking the average of each customer's loads over each hour of each weekday. We then take the maximum of those hourly averages for each customer and call that the maximum demand on the average day. The table then shows the average

value of those maximums across customers within each category. The metric is meant to reflect a customer's typical maximum usage on a weekday.

Although there are some differences in daily usage and maximum demand across different demographics, no strong trends emerge. For example, respondents aged 35-44 have higher daily average usage than those aged 25-34, but they also have higher usage than those aged 45-54, showing that there is no strong relationship between age and usage. Similar points hold for income and education levels.

Table 4-2: Usage by Demographic Characteristics from Survey Participant Load Profiles

Demographic Characteristic	Avg. Daily Usage (kWh)	Maximum Demand on the Average Day (kW)	Number of Customers
Gender			
Male	7.89	2.20	78
Female	8.89	2.34	19
Decline to State	9.18	2.38	1
Age			
25 – 34	7.21	1.92	5
35 – 44	9.47	2.39	24
45 – 54	8.29	2.32	32
55 – 64	6.88	2.06	26
65 or Older	7.67	2.12	10
Decline to State	9.18	2.38	1
Education			
High School	8.41	2.37	1
Some College	7.95	2.08	5
Graduated College	8.10	2.23	43
Graduate School	8.08	2.24	48
Decline to State	9.18	2.38	1
Income (1,000 $'s)			
Less than 50	10.00	3.04	1
50 – 75	9.14	2.23	4
75 – 100	7.69	2.04	8
100 – 125	7.80	2.15	8
125 – 150	8.39	2.39	15
150 – 175	8.12	2.38	13
175 – 200	9.46	2.32	3
More than 200	8.46	2.35	19
Decline to State	7.50	2.02	27

In addition to overall usage, it is of interest whether any demographic groups show a propensity for super off-peak charging. To address this, Tables 4-3 through 4-5 illustrate the average customer's share of super off-peak usage relative to total usage across different demographic categories. Although there is some variation across demographic groups, no strong patterns emerge.

Table 4-3: Usage Ratios by Age from Survey Participant Load Profiles

Age	Ratio of Avg. Hourly Super Off-peak Usage to Avg. Hourly Usage	Percent of Customers			Number of Customers
		EPEV-L	EPEV-M	EPEV-H	
25 - 34	0.66	20	60	20	5
35 - 44	0.70	21	42	38	24
45 - 54	0.72	19	38	44	32
55 - 64	0.66	27	31	42	26
65 or Older	0.69	20	30	50	10
Decline to State	0.70	0	100	0	1

Table 4-4: Usage Ratios by Education from Survey Participant Load Profiles

Education	Ratio of Avg. Hourly Super Off-peak Usage to Avg. Hourly Usage	Percent of Customers			Number of Customers
		EPEV-L	EPEV-M	EPEV-H	
High School	0.73	0	100	0	1
Some College	0.65	40	20	40	5
Graduated College	0.69	23	33	44	43
Graduate School	0.70	19	42	40	48
Decline to State	0.70	0	100	0	1

Table 4-5: Usage Ratios by Income from Survey Participant Load Profiles

Income	Ratio of Avg. Hourly Super Off-peak Usage to Avg. Hourly Usage	Percent of Customers			Number of Customers
		EPEV-L	EPEV-M	EPEV-H	
Less than 50	0.86	0	0	100	1
50 - 75	0.68	25	50	25	4
75 - 100	0.63	38	38	25	8
100 - 125	0.70	0	50	50	8
125 - 150	0.67	20	47	33	15
150 - 175	0.78	31	23	46	13
175 - 200	0.67	0	67	33	3
More than 200	0.71	11	42	47	19
Decline to State	0.66	30	30	41	27

These demographic analyses of charging demand show that demand characteristics are relatively constant across a wide range of incomes, educations and ages. This is a useful finding because it suggests that charging patterns are driven by unobservable characteristics that are not strongly correlated with demographics. In this case, it also further corroborates the idea that the presence of the timer, in conjunction with the TOU pricing, is sufficient to strongly influence charging patterns despite major differences in customer characteristics.

5 Electricity Demand Model

Although the descriptive graphs and statistics of charging load are highly informative about participant behavior, much of the audience for this pilot's results will be interested in understanding how the results could be extrapolated to other populations and other TOU pricing structures. To perform such an extrapolation requires a model of demand for EV charging. The primary output of such a model will be estimates of elasticities of demand, which are a way of summarizing how demand would respond to a range of pricing schedules.

This section describes the methodology for estimating an economic demand model of charging within the EV Pilot. First, we describe the structural model to be used for the analysis: a system of electricity demand equations derived from a generalized Leontief cost function. Second, we describe the estimation procedure: non-linear seemingly unrelated regression. Finally, we present results from the estimation and put them into a broader context.

5.1 Model

In order to estimate the effects of TOU pricing with the available data we need to model electricity demand within a theoretical framework. This framework allows us to interpret the raw data we see as the output of a decision process being made by the household. The decision facing a household at any given time is whether to charge the LEAF now or to charge it later. This decision will be affected by many factors, including the price of charging now and charging later, as well as household-specific factors, such as the need for use of a vehicle at the moment and the current state of charge in the vehicle. The prices affecting this decision are known and enter the model directly. Although the household-specific factors are also important to the charging decision, we cannot observe them and so they cannot be modeled specifically. These factors enter the model by causing unexplained variation around charging behavior that the model would predict based on price alone.

Focusing on the price-related aspects of the EV charging decision, the household must make a trade-off between paying the price to charge now and paying a possibly different price to charge later. In this case, that is the trade-off between charging during on-peak, off-peak and super off-peak periods. We define a set of parameters that determine how households make these tradeoffs and we refer to them as elasticities. An elasticity defines how much one quantity changes in response to a change in another quantity. Specifically, elasticities are expressed as what the expected percentage change of one quantity is with respect to the expected percentage change of another quantity.

In this case, the relevant elasticities are those that tell us how the quantity of EV charging during one period changes when the price of EV charging changes during that period (own-price elasticity) or during another period (cross-price elasticity). It is important to recognize that how much a household charges at any time is determined both by how much it costs at that time and by how much it costs at other times. For example, charging right now for $0.35/kWh might be quite unattractive if the price one hour from now is $0.15/kWh and might be quite attractive if the price one hour from now is $0.75/kWh. So, a household's charging at any given time is determined by the entire price schedule that the household faces, rather than just by the current price.

Elasticities of demand can be defined and estimated for virtually any good that consumers buy. Therefore, it is possible to interpret the elasticities estimated for this pilot in the context of elasticities of demand for other consumer goods. Elasticities of demand are influenced by a number of factors:

- Availability of substitutes: customers will be more sensitive to changes in price (more elastic) with the availability of close substitutes;
- Percentage of income: customers will be more sensitive to the price of a good the higher the price is in terms of the percentage of a typical customer's income;
- Necessity: customers will be less sensitive to price if a good is a necessity; and
- Duration: customers will be more sensitive to price in the long run, as it gives them more time to change behavior.

Table 5-1 provides examples of the own-price elasticity of demand for a number of goods. The way to interpret these values is that they indicate by what percentage the quantity demanded will change for a percentage change in price. Own-price elasticities generally have a negative sign, indicating that a price increase will result in a demand decrease. For example, the value of -0.1 for salt tells us that for every 1% increase in the price of salt, the quantity demanded will fall by 0.1%. Elasticities are generally considered according to their absolute values, so values closer to zero indicate items that have lower elasticities or have more inelastic demand. In general, items on the list that are necessities (such as salt) and that have no close substitutes (such as coffee) have elasticities much closer to zero (i.e., lower) than items that are luxuries (such as restaurant meals) and items that have close substitutes (such as Chevrolets).

Table 5-1: Example Elasticities[16]

Product	Elasticity
Salt	-0.1
Coffee	-0.3
Daily Electricity	-0.3 to -0.5
Fish (cod) consumed at home	-0.5
Taxi, short-run	-0.6
Movies	-0.9
Housing, owner occupied	-1.2
Private education	-1.1
Radio and television receivers	-1.2
Restaurant meals	-2.3
Foreign travel, long-run	-4.0
Chevrolet automobiles	-4.0
Fresh tomatoes	-4.6

[16] Elasticities in this table were taken from http://welkerswikinomics.wetpaint.com/page/PED+for+Various+Products. The original sources are: Economics: Private and Public Choice, James D. Gwartney and Richard L. Stroup, eighth edition 1997, seventh edition 1995; primary sources: Hendrick S. Houthakker and Lester D. Taylor, Consumer Demand in the United States, 1929-1970 (Cambridge: Harvard University Press, 1966,1970); Douglas R. Bohi, Analyzing Demand Behavior (Baltimore: Johns Hopkins University Press, 1981); Hsaing-tai Cheng and Oral Capps, Jr., "Demand for Fish" American Journal of Agricultural Economics, August 1988; and U.S. Department of Agriculture.

The model in this analysis defines the elasticities that determine a household's charging behavior as follows:

- ϵ_{p-p}: The elasticity of on-peak charging with respect to the price of on-peak charging. This quantity tells us how much we expect the quantity of on-peak charging to change when the price of on-peak charging changes. This is also referred to as the own-price elasticity of on-peak charging. The elasticity of off-peak charging with respect to its price and the elasticity of super off-peak charging with respect to its price have similar interpretations and are denoted by ϵ_{op-op} and $\epsilon_{sop-sop}$, respectively, where the *op* subscript refers to the off-peak period and *sop* refers to the super off-peak period;
- ϵ_{p-op}: The elasticity of on-peak charging with respect to the price of off-peak charging. This quantity tells us how much we expect the quantity of on-peak charging to change when the price of off-peak charging changes. This is referred to as a cross-price elasticity; and
- ϵ_{op-p}: The elasticity of off-peak charging with respect to the price of on-peak charging. This is another cross-price elasticity. The remaining cross-price elasticities are denoted similarly: ϵ_{sop-p}, ϵ_{p-sop}, ϵ_{op-sop}, and ϵ_{sop-op}. The notation can be somewhat confusing in that it is easy to note the double subscript and to think of these values as second derivatives. This is incorrect; the elasticities are first derivatives of a demand level with respect to a price level. Consequently, cross-price elasticities are not necessarily symmetric; for example, it is not necessarily the case that $\epsilon_{op-p} = \epsilon_{p-op}$. In fact, that will be true only rarely.

We have defined the elasticities as applying to charging during the TOU time periods. However, household decision-making probably takes place at a more granular level of time; households decide not only between charging during peak and off-peak periods, but also between charging at 2 PM and 3 PM, for example. However, the pricing experiment analyzed here only allows us to model decision-making over the TOU time blocks because those are the only time periods over which we observe different sets of prices. There are no customers in the experiment who face different prices at 2 PM than at 3 PM, so we cannot make any inference about how customers respond to different prices at those times.

To estimate the elasticities listed above, we now turn to the theoretical framework we referred to at the beginning of this section. We model the household as a unit or agent that produces many outputs. These outputs jointly contribute to the household's utility or well-being. We focus on one output in particular: the usage of an EV and the value of this output as a function of a set of inputs. Although it is the case that the household's use of an EV contributes to well-being in a way that depends on many other factors in the household, we lack sufficient data on each household to model this aspect of the problem. Instead, we suppose that the household's EV charging decisions are separable from its decisions to consume other goods and services. This means that we can model EV charging decisions separately from other household decisions. This strong assumption is virtually always used in demand modeling and is a result of the limited data available to modelers.

Using this framework, the inputs of household production become the electricity used in each of the pricing periods: peak, off-peak and super off-peak. We then hypothesize a cost function that arises from the solution of the optimal production that can be achieved under any set of prices. We estimate the parameters of the cost function using load data and the price variation across customers in the pilot. We then derive elasticities and calculate the impacts of the TOU rates using the estimated parameters of the cost function.

We model the energy used for EV charging with a generalized Leontief (GL) production function. The model we use is essentially a special case of the model presented in Aigner, Newman and Tishler (1994)[17], which is used to examine non-residential TOU rates in Israel. We use the case of the model with three period pricing: peak, off-peak and super off-peak.

The foundation of the model is the assumption that the household has a cost function where total household production and electricity prices during different periods of the day are inputs.[18] A cost function expresses the lowest cost at which a household can achieve a given level of production under a given set of prices. For any given set of prices, there is an optimal amount of production (and therefore utility) that the household can achieve. That production level has an associated cost at the given prices, which defines the cost function.

The cost function is defined such that the cost (C) is a function of output (y), prices ($\mathrm{p_i}$ for $\mathrm{i} = 1,2,3$), and parameters (β_{ij} for $\mathrm{i,j} = 1,2,3$). [19]

$$\mathrm{C} = \mathrm{y} \quad {}_{i=1}^{3} \quad {}_{j=1}^{3} \beta_{\mathrm{ij}} \ \mathrm{p_i p_j}^{\ 1\ 2} \qquad (1)$$

The data is then used to estimate the parameters of this function by deriving share equations for each period's share of usage (m_i) as a percentage of total average usage.[20]

$$m_i = \frac{{}_{j} \beta_{\mathrm{ij}} \ \mathrm{p_i p_j}^{\ 1\ 2}}{{}_{k} \ {}_{j} \beta_{\mathrm{kj}} \ \mathrm{p_k p_j}^{\ 1\ 2}} \qquad i = 1,2,3 \qquad (2)$$

In equation (2) the *j* and *k* indices each go from 1 to 3. Together, these share equations make up a system of seemingly unrelated regressions (SUR). The estimation of the SUR is done in STATA, using the *nlsur* function, which fits a system of nonlinear equations by feasible, generalized nonlinear least squares (FGNLS).

The estimated parameters are those that minimize the squared difference between the predicted and actual share for each month of each customer. From these estimated parameters, we calculate the own-price elasticities:

$$\epsilon_{ii} = \frac{1}{2} \ \frac{\beta_{\mathrm{ii}}}{{}_{kj} \beta_{\mathrm{ik}} \mathrm{p_k}^{\frac{1}{2}} \mathrm{p_i}^{-1\ 2}} - 1 \qquad i = 1,2,3 \qquad (3)$$

[17] Aigner, D. J., J. Newman and A. Tishler. "The Response of Small and Medium-size Business Customers to Time-of-Use (TOU) Electricity Rates in Israel." Journal of Applied Econometrics. (1994).

[18] A detailed description of the derivation of model is included in Appendix A.

[19] To keep notation simple in the model development we use 1, 2, 3 to denote the peak, off-peak and super off-peak periods, respectively, rather than p, op and sop.

[20] Note that the model does not differentiate among days and therefore within the model there is no difference between average usage shares at a daily level and average usage shares at a monthly level (as long as the distinction between weekends and weekdays is handled consistently). The model is estimated on monthly usage shares.

and cross price elasticities:

$$\epsilon_{ij} = \frac{1}{2} \frac{\beta_{ij} p_j^{1\ 2} p_i^{-1\ 2}}{{}_k \beta_{ik} p_k^{1\ 2} p_i^{-1\ 2}} \qquad i \neq j \qquad (4)$$

These elasticities correspond to those defined above. In both (3) and (4), the *k* index goes from 1 to 3.

5.2 Data

The data comes from 387 customers on the experimental TOU rates. The data covers the period from January 2011 until June 2012. The data originates as 15-minute interval measurements of kWh. The electricity rates from Table 2-2 are used as the prices in the model. The interval data is then converted into monthly shares of on-peak, off-peak and super off-peak consumption, by customer, as a fraction of total monthly usage respectively. Appendix B shows results for alternative choices of data as model inputs.

A good first step in analyzing experimental results is to assess the validity of the experiment. In this case, a crucial part of the experiment is that customers who opt to be part of the pricing experiment are randomly assigned to one of three rates. It is important therefore to assess whether that random assignment has been achieved without any selection bias entering the experiment. To address this, Table 5-2 shows the results of a validation exercise that demonstrates the successful randomization of customers onto the three different TOU rates. The table shows counts of customers with given observed characteristics across the three rates to demonstrate that the distributions of these characteristics are similar within each TOU rate. The observed characteristics in the table are climate zone, reported age from the survey, reported education, reported income and whether or not a customer responded to the survey.[21] The table shows both raw counts for each TOU rate within each characteristic category and the percentage of customers on each rate with that characteristic. As the table shows, in general, the distribution of each characteristic is similar across each of the rates.

Table 5-2 also shows the results of a statistical test that tells us whether there is any evidence that the distribution of a given characteristic is correlated with the TOU rates. This test is known as Fisher's exact test, and it is a common way of judging whether distributions of two variables are correlated within a population. In this case, small values in the far right column of the table would be evidence that there was a meaningful correlation between the distribution of the characteristic in the population and the TOU rate. This would be possible evidence that some type of selection bias had entered the experiment. Generally, values below 0.05 would be cause for further investigation. In this case, all values are above 0.2, indicating that there is no evidence of selection bias.

[21] Ideally, this table would also include a measure of usage from prior to the start of the pilot, and that may be included in subsequent analyses.

Table 5-2: Distributions of Characteristics Across Experimental Rates

Characteristic	Category	Count of Customers with Characteristic on Each Rate			Percentage of Customers On Rate with Characteristic			Fisher's Exact Probability
		EPEV-L	EPEV-M	EPEV-H	EPEV-L	EPEV-M	EPEV-H	
Climate Zone	Coastal	69	79	77	64	55	58	0.35
	Inland	39	65	56	36	45	42	
Age	25 - 34	1	3	1	5	8	3	0.89
	35 - 44	5	10	9	24	27	23	
	45 - 54	6	12	14	29	32	35	
	55 - 64	7	8	11	33	22	28	
	65 or Older	2	3	5	10	8	13	
	Decline to State	0	1	0	0	3	0	
Education	High School	0	1	0	0	3	0	0.78
	Some College	2	1	2	10	3	5	
	Graduated College	10	14	19	48	38	48	
	Graduate School	9	20	19	43	54	48	
	Decline to State	0	1	0	0	3	0	
Annual Income ($k)	Less than 50	0	0	1	0	0	3	0.68
	50 - 75	1	2	1	5	5	3	
	75 - 100	3	3	2	14	8	5	
	100 - 125	0	4	4	0	11	10	
	125 - 150	3	7	5	14	19	13	
	150 - 175	4	3	6	19	8	15	
	175 - 200	0	2	1	0	5	3	
	More than 200	2	8	9	10	22	23	
	Decline to State	8	8	11	38	22	28	
Survey Response	Yes	23	37	42	21	26	31	0.22
	No	85	106	94	79	74	69	

Table 5-3 shows the average usage in each period by rate group on weekdays and Table 5-4 shows the same for weekends. As was shown in Figures 3-1 and 3-2, the basic pattern is the same in each table, with the vast majority of charging occurring during the super off-peak period for all groups on both weekdays and weekends.

Table 5-3: Average Weekday Demand for Each Period by Rate

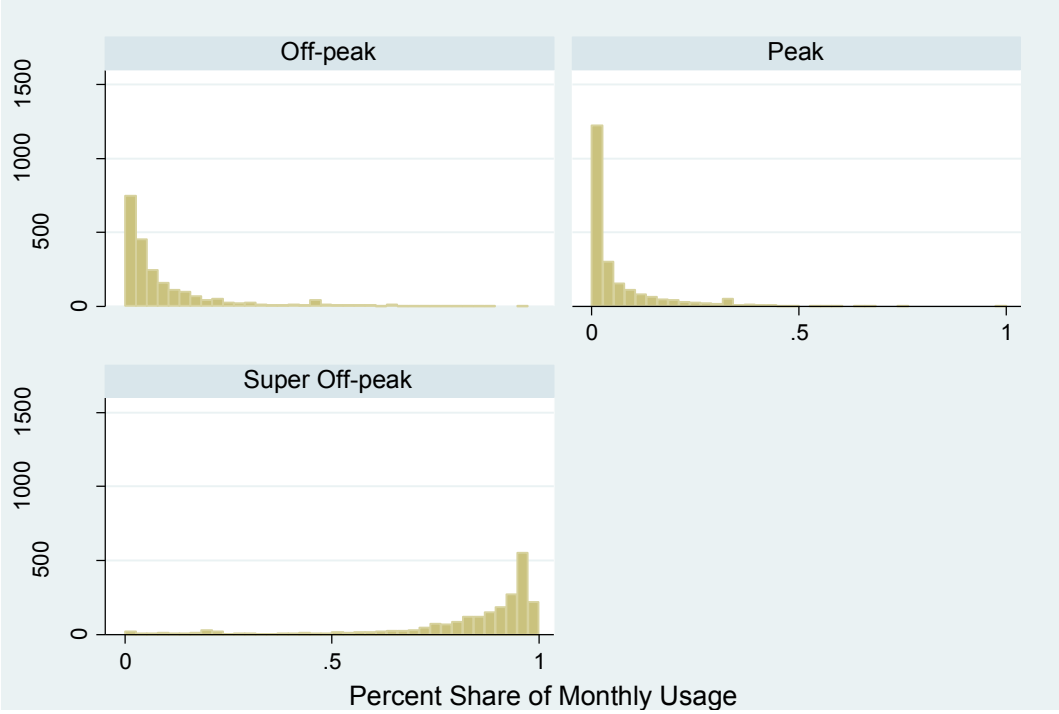
Rates	Average kW by Period		
	Peak	Off-peak	Super Off-Peak
EPEV-L	0.10	0.11	1.28
EPEV-M	0.09	0.09	1.44
EPEV-H	0.07	0.08	1.41

Table 5-4: Average Weekend Demand for Each Period by Rate

Rates	Average kW by Period		
	Peak	Off-peak	Super Off-Peak
EPEV-L	0.13	0.09	1.14
EPEV-M	0.11	0.08	1.29
EPEV-H	0.10	0.07	1.29

Figure 5-1 shows the histograms of observations of share by rate period for each customer-month included in the study. As the histograms show, the share of super off-peak charging is much higher than the share of peak and off-peak charging.

Figure 5-1: Histograms of Percent Shares of Monthly Usage



Over the time frame that data was collected a significant number of new customers enrolled each month. Therefore, if a customer did not have more than three days of data in their first month of enrollment, that month was dropped from the analysis.

Table 5-5 presents the results of a comparison of means for the peak period, off-peak period and super off-peak period usage for all pair-wise combinations of the TOU rates. A comparison of means is a statistical method that allows us to test the hypothesis that the difference in mean usage in the peak period between the customers with different rates is different than zero. Statistically significant differences are indicated by p-values less than 0.05. One minus the p-value indicates the confidence level for rejecting the null hypothesis of no difference between groups. For example, the results for weekdays indicate that the differences in peak period usage between customers on EPEV-H and EPEV-M are statistically significant at a level of 99%. The table shows values calculated over all days. Most of the pair-wise differences are statistically significant.

Table 5-5: Peak Period Pair-wise Comparison of Means

Day Type	Rates Compared	Mean On-Peak kWh Difference	P-Value	Mean Off-Peak kWh Difference	P-Value	Mean Super Off-Peak kWh Difference	P-Value
Weekdays	EPEVL-EPEVM	0.010	0.20	0.022	0.01*	0.163	0.00*
	EPEVL-EPEVH	0.029	0.00*	0.032	0.00*	0.133	0.01*
	EPEVM-EPEVH	0.018	0.01*	0.010	0.10	0.030	0.50
Weekends	EPEVL-EPEVM	0.019	0.01*	0.014	0.02*	0.150	0.00*
	EPEVL-EPEVH	0.027	0.00*	0.024	0.00*	0.146	0.00*
	EPEVM-EPEVH	0.008	0.22	0.010	0.03*	0.005	0.91

*P-values with asterisks indicate results significant at a 95% confidence value (i.e., p-values less than 5%)

5.3 Results

Table 5-6 presents the estimates of the β coefficients for the model. Separate models were estimated for weekdays and weekends, and the table shows sets of values calculated based on each. The reason for this separate weekday and weekend modeling is that we might expect that a household's decisions about charging would be quite different on weekends than it would be on weekdays. The parameter estimates in the table all have quite low standard errors and fairly small confidence intervals. The parameters for the weekday model are quite similar to the parameters for the weekend model. In fact, none of the weekend parameters are different from the weekday parameters at a 95% confidence level, despite the fact that all the parameter estimates have low standard errors. Only two of them (β_{11} and β_{13}) are different at an 80% confidence level, which is close to what would be expected due to random variation alone even if there were no systematic differences in customer behavior on weekends. This is not surprising given the results shown in Tables 5-3 and 5-4, which indicate that average charging patterns are quite similar between weekends and weekdays. For this reason, we focus on weekday results for the remainder of this section, recognizing that weekend results are not very different.

Table 5-6: Model Coefficient Estimates

Weekend/ Weekday	Parameter	Coefficient	Std. Err.	95% Confidence Interval	
Weekday	β_{11}	-0.014	0.001	-0.016	-0.011
	β_{12}	-0.008	0.003	-0.013	-0.003
	β_{13}	0.059	0.004	0.052	0.066
	β_{22}	-0.036	0.007	-0.049	-0.024
	β_{23}	0.113	0.008	0.098	0.128
	β_{33}	0.221	0.013	0.196	0.247
Weekend	β_{11}	-0.020	0.002	-0.024	-0.016
	β_{12}	-0.004	0.003	-0.010	0.002
	β_{13}	0.077	0.005	0.067	0.086
	β_{22}	-0.044	0.008	-0.059	-0.029
	β_{23}	0.120	0.008	0.105	0.136
	β_{33}	0.178	0.013	0.152	0.204

Recall, these parameters are estimated pieces of the cost function, they are not elasticity estimates. However, with these estimates we can derive the own-price elasticities and cross-price elasticities for each period.

Intuitively, all of the own-price elasticities should be negative, and all of the cross-price elasticities should be positive. Negative own-price elasticities (such as those shown in Table 5-1) indicate that the demand for electricity falls as the price increases. Positive cross-price elasticities indicate that two inputs are substitutes. This means that as the price of electricity increases during one time period, the demand for electricity increases in another period. Conversely, negative cross-price elasticities would indicate that goods are complements. This means that as the price of electricity increases during one time period, the demand for electricity decreases in another period. We would not expect

that to be the case with EV charging because we expect that a household has a fairly stable need for charging each day and that mainly they adjust by changing the time of day that they charge.

Table 5-7 shows the elasticity estimates for the weekday model.[22] Note that the elasticity formulas vary with price, so even though the estimated cost function parameters are constant across customers and across time, the elasticities themselves vary across both. Although standard errors are not shown, all of the elasticity estimates, with the exception of ϵ_{op-p}, are significantly different from zero at a 99% confidence level. The own-price elasticities are all negative, which is expected; because an increase in the price of an input should cause a decrease in demand.

The charging load shapes shown in Figures 3-1 through 3-3 are quite different from those associated with a typical whole-house residential TOU rate. Currently, our hypothesis is that in the presence of the EVSE or EV charging timer, customers are much more willing to shift load away from the peak and off-peak periods than they would be to shift other types of residential loads. Regardless of the explanation, based on the load shapes, we do not expect the elasticity estimates here to be comparable to those in other TOU experiments.

The estimated elasticities for the peak period and off-peak period are quite a bit higher than the most comparable results from an outside study that we are aware of – those from the California Statewide Pricing Pilot. In that study, daily own-price elasticities for residential customers were generally found to be in the range of negative 0.3-0.5.[23] The large own-price elasticity estimates may be due to the EVSE or EV charging timers, which make it easier for the customer to respond to the pricing signal and charge during the lowest price period. The own-price elasticity estimates for the super off-peak period are similar to those found in the Statewide Pricing Pilot.

Not all of the cross-price elasticities are positive, which is unexpected. We would expect that electricity usage between any two periods to be substitutes, however Table 5-7 suggests that electricity usage between the peak and off-peak hours are partially complementary because ϵ_{p-op} is negative across all price schedules and ϵ_{op-p} is negative for EPEV-L. This implies that all else being equal, an increase in the off-peak period price causes a decrease in the usage of electricity in the peak period. This seems unlikely to reflect actual behavior. This weakness in the results is due to our attempt to estimate substitution patterns between the peak and off-peak periods, both of which contain quite low levels of charging. The model requires a certain amount of meaningful variation in usage across the rate periods in order to be able to measure the implicit trade-offs that participants make when charging at different times. As we can see in Tables 5-3 and 5-4, the instantaneous level of charging at any given time is typically only slightly different between the off-peak and peak periods, and on the weekends it is actually slightly higher during the peak period. This suggests that many customers do not differentiate between the peak and off-peak periods in their charging decisions. A simple rule a customer might use to decide when to charge that could lead to this pattern would be "use the timer to charge overnight as much as possible, and then charge at other times as necessary." That could lead to the odd cross-price elasticities below. In that case, we would generally expect that the estimates would be statistically insignificant, and two of the eight unexpected values are, leaving

[22] Additional tables of results, including results from different subsets of the data are included in Appendix B.

[23] See "Impact Evaluation of the California Statewide Pricing Pilot." Prepared by Charles River Associates, (2005).

six that are not. This is more than we would expect due to chance alone if all the model's assumptions are satisfied, which suggests that some of the model's assumptions may be inaccurate. Currently there is no simple way to determine which of the model's assumptions lead to this unexpected finding. The model employs numerous simplifications of reality in order to produce a regression function with parameters that can be estimated based on the available data. This type of finding is to be expected in a fairly simple model of such a complex phenomenon and it is a well-recognized problem with demand modeling in general.

Our recommendation is to focus on the results for the super off peak period as compared to the other two periods and wait for additional data collection and analysis to determine whether reliable conclusions can be drawn about substitution between the peak and off-peak periods.

Table 5-7: Elasticity Results

Type of Price Elasticity	Elasticity	Rates					
		Summer			Winter		
		EPEV-L	EPEV-M	EPEV-H	EPEV-L	EPEV-M	EPEV-H
Own	ϵ_{p-p}	-0.81	-1.18	-1.67	-0.72	-1.00	-1.35
	ϵ_{op-op}	-0.82	-1.18	-1.20	-0.81	-1.04	-1.06
	$\epsilon_{sop-sop}$	-0.24	-0.28	-0.29	-0.23	-0.27	-0.28
Cross	ϵ_{p-op}	-0.13	-0.28	-0.41	-0.12	-0.22	-0.31
	ϵ_{op-p}	-0.56	0.81	0.60	-0.35	1.26	0.71
	ϵ_{p-sop}	0.94	1.42	2.11	0.83	1.22	1.74
	ϵ_{sop-p}	0.10	0.12	0.13	0.08	0.11	0.12
	ϵ_{op-sop}	0.90	1.36	1.43	0.87	1.18	1.24
	ϵ_{sop-op}	0.14	0.17	0.16	0.15	0.17	0.15

= statistically insignificant at 5% level

A few important patterns show up in Table 5-7. First, all of the own-price elasticities increase in absolute value as the price ratio between peak and off-peak or between peak and super off-peak prices increases across the price schedules. This indicates that as prices become more extreme in favoring certain time periods, households are more willing to respond by changing charging decisions. This is sensible; there may be a certain fixed cost to customers of responding at all and this cost might vary across customers. Faced with a weak price ratio, some customers might not find it worth it to respond at all, while others would respond weakly. As the price ratio increased, more and more customers might find it worthwhile to respond. This would lead to the pattern of estimated own-price elasticities shown in Table 5-7.

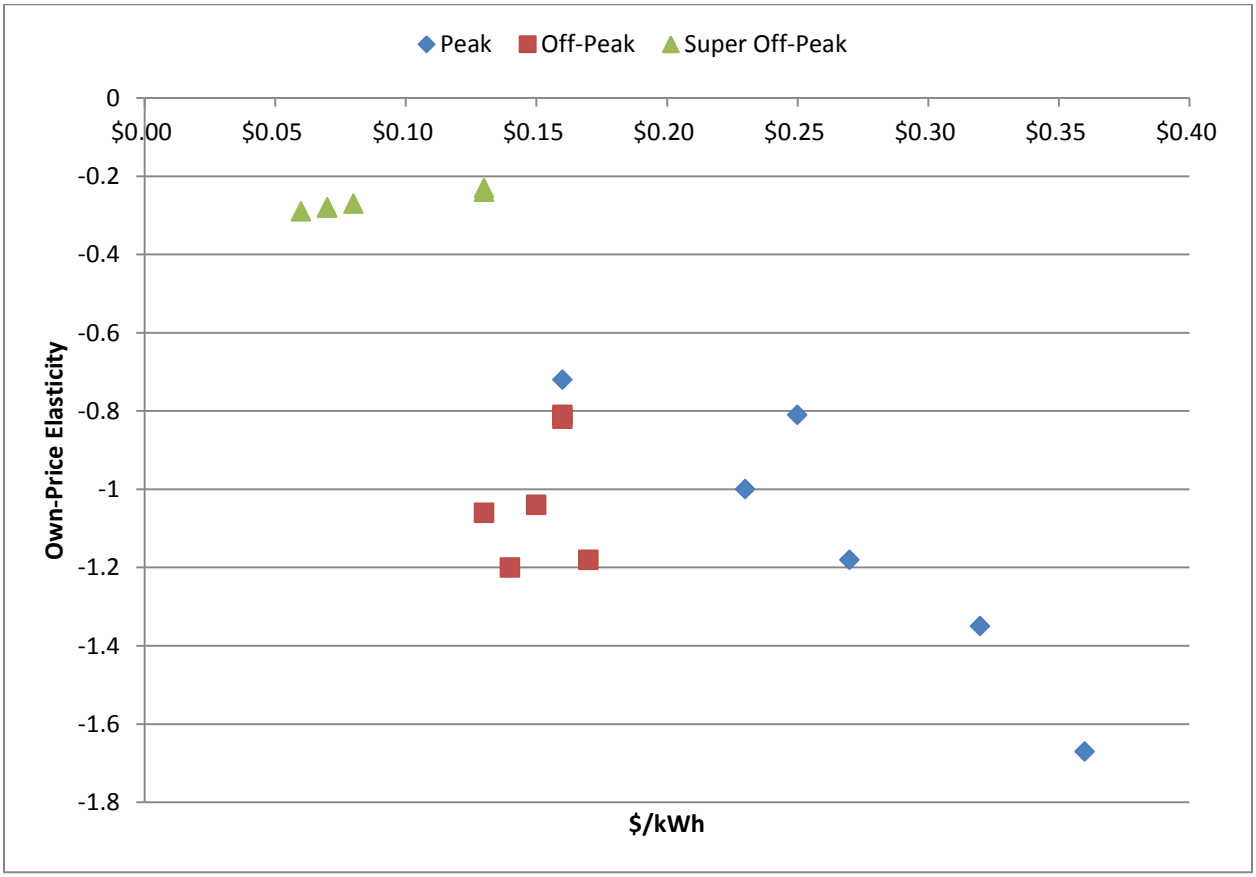
Second, and similar to the first pattern, own-price elasticities are greater in absolute value for the higher prices in each rate schedule. The peak own-price elasticity is greater than the off-peak own-price elasticity which, in turn, is greater than the super off-peak own price elasticity. This pattern holds for summer and winter across all three rates. A similar explanation as for the first pattern may

hold. In the super off-peak period, prices may be so low that small changes in price may not be worth responding to at all for some customers. As the price increases into the off-peak and peak periods, more and more customers will find it worthwhile to respond.

These two patterns described in the paragraphs above are shown in Figure 5-2, which graphs the elasticity estimates from Table 5-7 against the price for each estimate. The main notable feature of the graph is that across the time periods we see that customers are more responsive when the price is higher. Down in the low prices of the super off-peak period, customers don't respond much to price changes– probably because the prices are so low that it's not worth paying too much attention. Up in the peak period price range, customers respond a lot to price changes. As stated earlier, price elasticities are usually considered in terms of the magnitude of their absolute value, with large absolute values indicating more elastic demand. Specifically, a price elasticity of absolute value greater than 1 is usually considered highly elastic.

Importantly, during the peak period alone we also see that as the price gets higher, customers continue to get more and more price responsive. Customers facing the highest prices are also the most responsive (meaning customers on EPEV-H during the summer). This says that a preliminary result is that customers respond to prices and the biggest price response occurs towards the upper end of the prices currently being tested.

Figure 5-2: Elasticity Results Versus Prices During Each Period



Finally, and again, similarly, the cross-price elasticities tend to be higher for the high price periods and lower for the low price periods. This pattern holds both across periods and across rate schedules (with the already mentioned exception of ϵ_{op-p} and ϵ_{p-op}). For example, the elasticity of on-peak charging with respect to the price of super off-peak charging (ϵ_{p-sop}) is much greater than the elasticity of super off-peak charging with respect to the price of on-peak charging (ϵ_{sop-p}). This pattern, which also holds between off-peak and super off-peak periods, is probably partially due to the fact that so much charging takes place during the super off-peak period for all rates despite price differentials across rates. Fairly large changes in the peak price, for example, have led to little change in the pattern of super off-peak charging across rates. It is less clear why the low rates of charging during the peak and off-peak periods have led to higher cross-price elasticities for those quantities.

To assess how well the model fits the data, we use the model to predict usage shares for each period based on the TOU price schedules. The model does a good job of predicting the average monthly share of usage for each of the rate groups. Table 5-8 shows the predicted versus actual shares for each of the TOU periods. The actual shares never deviate by more than 1% from the predicted share. This indicates that the model fits the data well on average at these prices.

Table 5-8: Predicted Versus Actual Usage Shares

Rates	Shares (%)					
	Predicted			Actual		
	EPEV-L	EPEV-M	EPEV-H	EPEV-L	EPEV-M	EPEV-H
EPEV-L	6	10	84	6	10	84
EPEV-M	8	13	78	9	13	78
EPEV-H	7	11	82	7	11	82

Note: Not all shares total 100% due to rounding.

The R^2 value is an additional way to consider how well the model fits the data. The model consists of two equations being fit to the data. The equations describe the share of usage in the peak period and the super off-peak period. The off-peak usage is fully determined by the other two equations because the total shares of usage must sum to one. The R^2 value of the super off-peak peak period equation is 94%, indicating a very close fit of the model to the data. The R^2 value of the peak period equation is 33%, indicating a much looser fit, with more unexplained variation. Essentially, the model can predict super off-peak period usage well because such a large fraction of charging occurs then. Peak period charging, on the other hand, is much rarer, more idiosyncratic and difficult to predict accurately. As more data is collected, the model's ability to fit peak period charging may increase, which would lead to a higher R^2 value.

Having estimated this model, a useful feature is that it allows us to predict what usage behavior would look like under alternative price schedules for the same population. The model we used provides us with estimated demand functions. We can input different hypothetical prices into the estimated demand functions to see how the share distributions vary. Table 5-9 shows the predicted shares of usage for various TOU rates. For example, it allows us to compare the impact of an extreme rate with a price ratio of 1:2:13 to the EPEV-H summer rate which has a ratio of 1:2.3:5.7

Table 5-9: Shares of Usage for Different Pricing

Ratio of Prices (sop:op:p)	Shares (%)		
	Peak	Off-peak	Super Off-peak
1:2.3:5.7	5	10	85
1:3:8	3	7	90
1:2:13	0	6	94

The results indicate that customers are responding to the price incentives of charging during super off-peak hours. Table 5-10 shows the estimated usage values in kWh for each rate period under the alternative scenarios analyzed in Table 5-10. Under the most extreme rate scenario, with a peak to super off-peak ratio of 1:13, the peak usage falls to less than 1% of total usage.

Table 5-10: Total Daily Usage by Period for Different Pricing (kWh)

Price Ratio	Peak	Off-peak	Super Off-peak
1:2.3:5.7	0.50	0.88	7.76
1:3:8	0.23	0.66	8.25
1:2:13	0.00	0.55	8.59

SDG&E's standard residential rate is an increasing block rate, which means that ideally we would be able to predict usage under that schedule. Block rates provide different incentives than TOU rates, with a focus on the distribution of usage over the month rather than the distribution of usage during the day. Customers within this experiment were not subject to increasing block rates for their charging, so there is no way to use the data in this experiment to develop a model that accounts for behavior under TOU rates and an increasing block rate.

Overall, the results of this section show that customers in the SDG&E Rate Experiment have usage behavior that can be reasonably well modeled using a standard economic demand model. However, it is important to note that peak period charging in particular has much variation in it that is unexplained by the model. This modeling exercise may become more informative over the second year of the pilot if customers start to deviate more from super off-peak charging.

6 Conclusions

This report is a summary of preliminary results for the first year for the SDG&E EV Rate Experiment. Conclusions from this report may change as additional data is collected and analyzed. The final report for this experiment is expected in 2013.

The key findings of this report are that:

- The majority of charging takes place during the super off-peak period, which is likely driven by the use of EVSE and EV charging timers;
- This pattern constitutes strong evidence of the impact of the TOU rate on charging behavior;
- There is evidence that customer behavior is changing over time; and
- Charging behavior does not significantly vary across different demographic groups of income, age or education.

A significant amount of evidence suggests that charging behavior is driven by the use of EVSE or EV charging timers. Sixty-three percent of all charging events begin between the hours of 12 AM to 1 AM and 80% of total EV charging usage occurs during the super off-peak period. This suggests that customers are setting their timers to start charging at the beginning of the super off-peak period to take advantage of the lowest electricity rate.

Aside from the strong tendency towards super off-peak charging, there is further evidence that the TOU rates are impacting customer EV charging behaviors. Looking across the different TOU rate groups, customers on the flattest TOU rates charge less during the super off-peak hours and more during the peak hours than the other groups of customers who face steeper price increases in the peak period. Examining usage within customers, customers are doing the majority of EV charging during the lowest priced periods and the estimated own-price elasticities are relatively large.

Customer EV charging behavior appears to be changing over time. Over the course of the experiment, customers on the flattest TOU rate have seen the largest decline in the super off-peak period's share of total usage. Conversely, customers on the steepest TOU rate have seen virtually no decline in the super off-peak period's share of total usage. This suggests that customers may be learning more about their rates over time and adjusting their behavior accordingly. However, these differences are currently driven by a small number of customers, so it will be important to see whether they hold up over time.

The results of this analysis must be viewed in the proper context. All of the information used in the analysis comes from customers who are early adopters of new technology. For this reason we cannot assume that the behavior observed in them will necessarily be demonstrated by a larger population after widespread EV technology adoption. However, the analysis contained in this report is a necessary starting point and provides valuable information about general trends in the participant population.

Over the course of the next year of the study it will be useful to repeat the same analyses to determine whether customers diverge in their charging behavior according to the price signals they face.

Appendix A. Model Development

A.1. Model

In order to estimate the effects of TOU pricing with the available data we need to model electricity demand within a structural framework. For this reason, we model the household as a firm that produces many outputs. We focus on one output in particular: the usage of an electric vehicle. Using this framework, the inputs of production become the electricity used in each of the pricing periods: peak, off-peak and super off-peak, with all other inputs, and their corresponding prices, being held constant. We can then estimate parameters of the cost function, which is analytically derived from the hypothetical production function, by using load data and the price variation across different customers. The estimated parameters of the cost function provide us with the input demand functions, from which we can then derive elasticities and calculate the impacts of the TOU rates.

We model the energy usage of the electric vehicle supply equipment (denoted EVSE) with a generalized Leontief (GL) production function. Using this model we can derive a demand system for EVSE energy consumption that represents each pricing period's demand. The model we use is essentially a special case of the model presented in Aigner, Newman and Tishler (1994), who examine non-residential TOU rates in Israel. We use the case of the model with three period pricing: peak, off-peak and super off-peak.

The GL production function was introduced by Diewert (1971)[24] to obtain input demand equations that are linear in technological parameters for the purposes of facilitating econometric estimation. We choose the GL function because it is sufficiently sophisticated to take advantage of the experimental design, and simple enough to satisfy global concavity for the sake of estimation (and therefore ensuring unique solutions to the estimation procedure). More complex models, like the CES-GBC, include more parameters and do not necessarily satisfy global concavity.[25] Global concavity is important for optimization problems, because it implies a unique solution to a problem. In this setting, concavity means that there is a set of parameters for our production function that minimize the aggregate differences between the actual and predicted values.

Faruqui and Malko (1983)[26] claim that the GL specification offers a degree of flexibility, in that it imposes few restrictions on the substitution possibilities. This feature allows us to take full advantage of the experimental design (having three distinct TOU rates for each of the three time periods) and estimate own-price elasticities and cross-price elasticities between all of the time periods. Other

[24] Diewert, W. E. "An Application of the Shephard Duality Theorem: A Generalized Leontief Production Function." Journal of Political Economy. (1971).

[25] Tishler, A. and S. Lipovetsky, "The Flexible CES-GBC Family of Cost Functions: Derivation and Application", Review of Economics and Statistics. (1997).

[26] Faruqui, A and J. R. Malko. 1983. "The Residential Demand for Electricity by Time-of-Use: A Survey of Twelve Experiments with Peak Load Pricing." Energy Vol. 8. (1983).

models, like the translog model used in Chung and Aigner (1981)[27] are incapable of testing the hypothesis of zero substitutability between periods.[28]

The GL model also tends to perform well with relatively large price variations. In a similar experiment looking at commercial TOU rates, Woo (1985) highlights the benefits of the GL specification when examining TOU price variations ranging from 8:1 to 2:1 in peak to off-peak ratios. Woo found that the GL model produced a better fit, and more intuitive elasticity results, than the translog model, which produced counter-intuitive positive own-price elasticities for some of the pricing periods.

The model will use 15-minute interval data that measures the usage of the EVSE. The 15-minute data is aggregated such that dependent variables are the monthly average shares of on-peak, off-peak, and super off-peak, weekday electricity consumption. Therefore, the shares represent each pricing period's fraction of the total monthly weekday energy consumed by the EVSE. Share models are used as a way of normalizing EVSE loads so that relative usage within a given pricing period can be easily compared across customers in a panel model.

The foundation of the model is a three input generalized Leontief production function of the form:

$$y = \sum_{i=1}^{3} \sum_{j=1}^{3} \alpha_{ij} \, x_i x_j^{\frac{1}{2}} \qquad \text{(A-1a)}$$

where y is output, x_i for $i = 1,2,3$ are inputs (which in this is case electricity used during each price period), and α_{ij} for $i, j = 1,2,3$ are unknown parameters. This function describes how a household in the study produces value from its charging consumption at different times of day.

Given equation (A-1a), we assume that a customer can then find the minimum cost usage allocation to produce a given feasible amount of value for any price schedule: p_i for $i = 1,2,3$. Solving this cost minimization problem,

$$\min \sum_{i=1}^{3} x_i p_i \qquad \text{(A-1b)}$$

subject to the constraint

$$y = \sum_{i=1}^{3} \sum_{j=1}^{3} \alpha_{ij} \, x_i x_j^{\frac{1}{2}} \qquad \text{(A-1c)}$$

[27] Chung, C. and D. J. Aigner. "Industrial and commercial demand for electricity by time-of-day: A California case study," The Energy Journal, (1981).

[28] Woo, C. "Demand for Electricity of Small Nonresidential Customers under Time-Of-Use (TOU) Pricing." The Energy Journal. (1985).

results in the cost function of Aigner, Newman and Tishler (1994):

$$C = y \sum_{i=1}^{3} \sum_{j=1}^{3} \beta_{ij} \; p_i p_j^{\;1\;2} \tag{A-2}$$

With input prices p_i for $i = 1,2,3$ and parameters β_{ij} for $i, j = 1,2,3$ which are unknown parameters to be estimated.

At the point where costs are minimized, the rate of change of the cost as price changes is equal to the level of demand of that commodity. Therefore, taking the partial derivatives of the cost function with respect to input price, we get the demand for each input i:

$$\frac{\partial C}{\partial p_i} = x_i = y \sum_{j=1}^{3} \beta_{ij} \; \frac{p_j}{p_i}^{\;1\;2} \qquad i = 1,2,3 \tag{A-3}$$

The resulting share equations are:

$$m_i = \frac{x_i p_i}{\sum_k x_k p_k} = \frac{\sum_j \beta_{ij} \; p_i p_j^{\;1\;2}}{\sum_k \sum_j \beta_{kj} \; p_k p_j^{\;1\;2}} \qquad i = 1,2,3 \tag{A-4}$$

where m_i is the share of the ith input in total electricity expenditure and x_i is the electricity use during the period when p_i is in effect. Note that in the denominator of (A-4), the *k* and *j* indices each go from 1 to 3. Dividing the top and the bottom of equation (A-4) by p_i demonstrates that the share equations are dependent only on the price ratios $p_j \;\; p_i$, for $j = 1,2,3$. Taking the derivative of the demand (A-3) with respect to the prices, the own-price and cross-price elasticities then respectively become:

$$\epsilon_{ii} = \frac{\partial \ln(x_i)}{\partial \ln(p_i)} = \frac{\partial x_i}{\partial p_i} * \frac{p_i}{x_i} = \frac{1}{2} \; \frac{\beta_{ii}}{\sum_j \beta_{ij} p_j^{1\;2} p_i^{-1\;2}} - 1 \qquad i = 1,2,3 \tag{A-5a}$$

and:

$$\epsilon_{ij} = \frac{\partial \ln(x_i)}{\partial \ln(p_j)} = \frac{\partial x_i}{\partial p_j} * \frac{p_j}{x_i} = \frac{1}{2} \frac{\beta_{ij} p_j^{1\;2} p_i^{-1\;2}}{\sum_j \beta_{ij} p_j^{1\;2} p_i^{-1\;2}} \qquad i \neq j \tag{A-5b}$$

In the denominator of (A-5a) and (A-5b), the *j* index goes from 1 to 3. Weather may impact electricity usage; therefore, we define:

$$\beta_{ij} = \beta_{ij}^0 + W\beta_{ij}^1 \tag{A-6}$$

where W is the average monthly weekday measurement of cooling degree hours (CDH) taken at 2 PM PST.[29] Finally, equations (A-4) are homogenous of degree zero in the β_{ij}'s; therefore we impose the following restrictions to ensure identifiability:

$$\sum_i \sum_j \beta_{ij}^0 = 1 \quad 2 \tag{A-7a}$$

and:

$$\sum_i \sum_j \beta_{ij}^1 = 0 \tag{A-7b}$$

where the *i* and *j* indices each go from 1 to 3.

A.2. Estimation

We specify classical additive disturbances u for each of the share equations (A-4) which result in equations (A-8) below. Aggregated 15-minute data is used to estimate the monthly share equations (A-4) subject to the constraints (A-6), (A-7a) and (A-7b). Since the shares must add up to one, the equation for the super off peak period is deleted ($m_3 = 1 - m_1 - m_2$). The remaining share equations from (A-5), subject to the constraints (A-6), (A-7a) and (A-7b), are then estimated using nonlinear seemingly unrelated regressions (SUR).

This results in the system:

$$m_i = \frac{\sum_j \beta_{ij} \; p_i p_j^{\quad 1 \;\; 2}}{\sum_k \sum_j \beta_{kj} \; p_k p_j^{\quad 1 \;\; 2}} + u_i \qquad i = 1,2 \tag{A-8}$$

where:

$$\beta_{ij} = \beta_{ij}^0 + W\beta_{ij}^1 \text{ for } i,j = 1,2,3 \tag{A-9a}$$

$$\beta_{33}^1 = \sum_i \sum_j \beta_{ij}^1 \; for \; i,j \neq 3,3 \tag{A-9b}$$

and:

$$\beta_{33}^0 = \frac{1}{2} - \sum_i \sum_j \beta_{ij}^0 \; for \; i,j \neq 3,3 \tag{A-9c}$$

The estimation of the SUR model will be done in STATA, using the *nlsur* function, which fits a system of nonlinear equations by feasible generalized nonlinear least squares (FGNLS). FGNLS is used because the error variance matrix is unknown, but can be estimated in the first stage of the estimation (see (A-11) below).

[29] The actual implementation of the model in this paper did not include weather because the model would not converge on a solution when weather was included.

The NLSUR model takes into account the notion that the errors between two nonlinear regression equations can be correlated. If these errors are correlated, the SUR model can improve the efficiency of the estimation. In the case of the share equations we have derived above, this relationship should be clear, as the total shares: peak, off-peak and super off-peak, must add up to one. Therefore, overestimating one share should result in an underestimation of one or more of the other shares.

Using matrix notation, the FGNLS estimator for N observations is β, such that:

$$\beta \equiv argmin_{\beta} \sum_{j=1}^{N} m_j - g(x_j, \beta)\ \delta'\ m_j - g(x_j, \beta)\ ' \qquad \text{(A-10)}$$

Where $g(x_j, \beta)$ is the vector of functions $g(x_{ji}, \beta) = m_{ji} + u_{ji}$ for $i = 1,2$ given in (A-6) for the jth observation.

The FGNLS is essentially a two stage process. In the first step we run the NLS regression assuming $\delta = I\ \ identity\ matrix$ in (A-10). This will give us a consistent estimate of β, β_{NLS} which is then used to estimate δ as follows.

$$\delta = \sum_{i=1}^{N} \frac{1}{N} u_i{}'\ u_i \qquad \text{(A-11)}$$

where:

$$u_i = m - g(x_i, \beta_{NLS}) \qquad \text{(A-12)}$$

δ is then plugged into (A-10) for δ which gives us a new estimate of β, β_{FGNLS} .

Appendix B. Results from Different Subsets of Data

The following tables show the results of the model when it is estimated for different subsets of the data. The first subset contains all data later than June 1, 2011. This is when enrollment leveled off. The results from this subset of data are presented in Tables B-1 and B-2. The results of this model are very similar to those that used the entire dataset.

Next, Tables B-3 and B-4 present the results of the model using only summer data. Here we see that every elasticity is closer to zero compared to the complete data set and Table B-1. This is expected, since the price differentials are larger in the summer while usage patterns are similar. Therefore, every change in usage across periods will be accompanied by a relatively larger percent change in price, and thus lead to a smaller elasticity. This notion is reinforced by Tables B-5 and B-6, which present the results of the model using only the winter data. Here we see that all of the elasticities are further from zero relative to the complete data set and Table B-2.

As was the case in the primary model, estimation of ϵ_{op-p} continues to be problematic in these examples. The elasticity calculations are a function of the β parameters, and sometimes the denominator of the calculation can be quite close to zero due to combinations of parameters that would otherwise seem reasonable. We will investigate this issue further if it continues to arise.

Table B-1: SUR Model Results Monthly Data (All Data Later than June 1, 2011)

Parameter	Coefficient	Std. Err.	z	P>|z|	95% Confidence Interval	
β_{11}	-0.014	0.001	-10.57	0	-0.016	-0.011
β_{12}	-0.008	0.003	-3.02	0.003	-0.013	-0.003
β_{13}	0.059	0.004	15.64	0	0.052	0.066
β_{22}	-0.034	0.007	-5.13	0	-0.047	-0.021
β_{23}	0.109	0.008	13.87	0	0.093	0.124
β_{33}	0.228	0.013	17.73	0	0.203	0.253

Table B-2: Elasticity Results (All Data Later than June 1, 2011)

Type of Price Elasticity	Elasticity	Rates					
		Summer			Winter		
		EPEV-L	EPEV-M	EPEV-H	EPEV-L	EPEV-M	EPEV-H
Own	ϵ_{p-p}	-0.81	-1.18	-1.69	-0.72	-1.01	-1.36
	ϵ_{op-op}	-0.80	-1.14	-1.16	-0.79	-1.01	-1.03
	$\epsilon_{sop-sop}$	-0.23	-0.28	-0.29	-0.22	-0.26	-0.28
Cross	ϵ_{p-op}	-0.13	-0.29	-0.42	-0.12	-0.23	-0.32
	ϵ_{op-p}*	-0.45*	1.38*	0.79*	-0.29*	3.66*	1.01*
	ϵ_{p-sop}	0.94	1.43	2.14	0.83	1.23	1.75
	ϵ_{sop-p}	0.10	0.12	0.13	0.08	0.11	0.12
	ϵ_{op-sop}	0.89	1.33	1.40	0.86	1.15	1.22
	ϵ_{sop-op}	0.14	0.16	0.15	0.14	0.16	0.15

*Statistically insignificant at the 5% level.

Table B-3: SUR Model Results Monthly Data (Summer Data Only)

Parameter	Coefficient	Std. Err.	z	P>|z|	95% Confidence Interval	
β_{11}	-0.012	0.002	-6.56	0	-0.016	-0.008
β_{12}	-0.008	0.003	-2.42	0.015	-0.015	-0.002
β_{13}	0.057	0.005	10.7	0	0.046	0.067
β_{22}	-0.026	0.008	-3.37	0.001	-0.041	-0.011
β_{23}	0.097	0.011	9.21	0	0.076	0.117
β_{33}	0.247	0.019	12.92	0	0.210	0.285

Table B-4: Elasticity Results (Summer Data Only)

Type of Price Elasticity	Elasticity	Rates		
		Summer		
		EPEV-L	EPEV-M	EPEV-H
Own	ϵ_{p-p}	-0.77	-1.07	-1.43
	ϵ_{op-op}	-0.74	-0.99	-1.01
	$\epsilon_{sop-sop}$	-0.21	-0.26	-0.27
Cross	ϵ_{p-op}	-0.14	-0.29	-0.40
	ϵ_{op-p}*	-0.31*	-2.08*	3.83*
	ϵ_{p-sop}	0.91	1.32	1.85
	ϵ_{sop-p}	0.09	0.11	0.13
	ϵ_{op-sop}	0.84	1.18	1.26
	ϵ_{sop-op}	0.12	0.15	0.14

*Statistically insignificant at the 5% level.

Table B-5: SUR Model Results Monthly Data (Winter Data Only)

Parameter	Coefficient	Std. Err.	z	P>|z|	95% Confidence Interval	
β_{11}	-0.017	0.002	-9.1	0	-0.021	-0.013
β_{12}	-0.010	0.004	-2.28	0.023	-0.018	-0.001
β_{13}	0.067	0.006	10.88	0	0.055	0.079
β_{22}	-0.037	0.013	-2.8	0.005	-0.063	-0.011
β_{23}	0.120	0.014	8.39	0	0.092	0.148
β_{33}	0.200	0.020	10	0	0.161	0.239

Table B-6: Elasticity Results (All Winter Data Only)

Type of Price Elasticity	Elasticity	Rates		
		Winter		
		EPEV-L	EPEV-M	EPEV-H
Own	ϵ_{p-p}	-0.75	-1.14	-1.69
	ϵ_{op-op}	-0.80	-1.03	-1.06
	$\epsilon_{sop-sop}$	-0.25	-0.29	-0.31
Cross	ϵ_{p-op}	-0.14	-0.30	-0.47
	ϵ_{op-p}*	-0.32*	4.05*	1.09*
	ϵ_{p-sop}	0.89	1.42	2.29
	ϵ_{sop-p}	0.09	0.12	0.14
	ϵ_{op-sop}	0.88	1.21	1.29
	ϵ_{sop-op}	0.16	0.17	0.16

*Statistically insignificant at the 5% level.