Application No.:	A.13-12-___
Exhibit No.:	SCE-1
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SOUTHERN CALIFORNIA
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(U 338-E)

PREPARED TESTIMONY IN SUPPORT OF SCE'S 2013 RATE DESIGN WINDOW APPLICATION

Before the

Public Utilities Commission of the State of California

Rosemead, California
December 24, 2013

PREPARED TESTIMONY IN SUPPORT OF SCE'S 2013 RATE DESIGN WINDOW APPLICATION

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I.

INTRODUCTION

In this Rate Design Window (RDW) Application, Southern California Edison Company (SCE) requests approval by the California Public Utilities Commission (Commission) of two proposals: First, SCE proposes revisions to "Option R," an optional rate for certain non-residential customers with onsite renewable generation. Related to this proposal, SCE requests Commission approval to maintain the current 150 megawatt (MW) cap on Option R participation, which applies to the cumulative installed distributed generation output capacity of Option R accounts. Second, SCE seeks approval of new electric vehicle (EV) rates for residential customers.

As explained in more detail below, the first proposal (regarding Option R) is included in this RDW Application in accordance with SCE's 2012 General Rate Case (GRC) Phase 2 Medium and Large Commercial Customer Rate Design Settlement Agreement, which the Commission approved in Decision (D.) 13-03-031. The second proposal (regarding the EV rates) is included in this Application pursuant to D.11-07-029, an order arising from the Phase 2 Decision Establishing Policies to Overcome Barriers to Electric Vehicle Deployment (D.11-07-029).

II.

OPTION R PROPOSAL

A. Description of Current Option R

Option R rate schedules are available to commercial and industrial customers with demands greater than 20 kW but not exceeding four MW who employ Renewable Distributed Generation Technologies.[1] Option R is available to certain customers on Schedules TOU-8, TOU-GS-3 and TOU-GS-2 to the extent that they are not also standby customers (who are ineligible for Option R pursuant to the applicable standby tariffs). Eligible customers must install, own, or operate an eligible onsite Renewable Distributed Generation Technologies system with a net capacity that is 15 percent or greater than the customer's annual peak demand.[2] Option R is structured so that SCE recovers all generation-related capacity costs, and a portion of the distribution and transmission-related capacity costs, through volumetric energy charges on a cent per kilowatt-hour (kWh) basis.

B. Regulatory Background Of Option R

Option R was first adopted in D.09-08-028, which approved a settlement resolving SCE's 2009 GRC Phase 2 proceeding. The settlement agreement adopted in D.09-08-028 described Option R as an "experimental rate," and specified that "[p]articipation on [Option R] will be limited to a cumulative installed distributed generation output capacity of 150 MW for all eligible rate groups."[3] The settling parties in the 2009 GRC Phase 2 proceeding agreed to use a proxy value to measure the expected diversity benefit[4] of Option R customers for three years, and then revisit and quantify that proxy value in the 2012 GRC Phase 2 after studies measuring diversity were undertaken. Thus, in its 2012 GRC Phase 2, SCE

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1 This term is defined as solar, wind, fuel cells, and any other renewable generation technology as defined in the Statewide California Solar Initiative, the Self-Generation Incentive Program, or their successors.

2 Customers with multiple onsite generation units associated with a single service account, where one or more of the generators is a non-renewable generating unit, are not eligible for the Option R schedules.

3 D.09-08-028, Attachment D, p. 12.

4 "Diversity" measures how a rate class contributes to the circuit peak. A group that is considered to be diverse reflects a relatively flat or an inverse load profile. Solar customers can improve the diversity of a given class profile by virtue of generating energy during peak periods, thus contributing towards reducing the class profile peak. This reduction in the class peak represents a diversity benefit.

proposed to retain Option R but, consistent with the parties' agreement from the 2009 GRC Phase 2 settlement, also proposed to update the design of the rate to take into account a 2011 SCE study on the "Impact of Customers' Solar PV Installations on System Load" (2011 Study). Using the TOU-GS-3 rate class as a representative sample, the study concluded that a 32% offset on distribution demand charges and a 24% offset on transmission demand charges would appropriately reflect the diversity benefit attributable to photovoltaic (PV) installation.

The relevant parties[5] to the 2012 GRC Phase 2 proceeding again reached a settlement on Option R rate design, adopted by the Commission, which maintained the methodology from the 2009 settlement except that the proxy diversity adjustments factors from 2009 were replaced by adjustment factors based on the study performed by SCE. The parties also agreed to preserve the 150 MW cap on Option R participation,[6] but agreed that once the cap was reached, SCE would offer a maximum of 50 MW of Option A (another generation-as-energy type of rate) to a subset of TOU-8 customers who would otherwise be eligible for Option R.[7] Germane to this RDW Application, the settling parties also agreed as follows:

> SCE will assess the cost-effectiveness of Option R after the Commission has completed the cost-effectiveness study described in D.12-05-036, Ordering Paragraph 5. SCE will use the results of the Commission's study, along with any additional information from other cost-effectiveness studies, including the study that SCE performed in this proceeding, to determine whether and how Option R rates should be modified or expanded. SCE will file these recommendations as part of a Rate Design Window (RDW) application in December 2013.[8]

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5 The parties to the Medium and Large Commercial Customer Rate Design Settlement Agreement were as follows: SCE, the Federal Executive Agencies, the California Manufacturers and Technology Association, the California Large Energy Consumers Association, Energy Users Forum, Solar Energy Industries Association, the County of Los Angeles, and the Energy Producers and Users Coalition.

6 D.13-03-031, Attachment D, p. 19.

7 Before D.13-03-031 was issued, the only Schedule TOU-8 customers who could take Option A were cold ironing and permanent load shifting (PLS) customers. The settling parties' agreed to preserve the Option R cap, but to add fifty additional megawatts of Option A for customers *other than* PLS and cold-ironing customers. SCE does not propose, in this RDW, to expand the 50 MW cap or to alter Option A's eligibility terms, as the settlement did not provide an "off-ramp" for SCE to revisit this issue any time earlier than its next GRC Phase 2.

8 D.13-03-031, Attachment D, p. 22.

The Commission's cost-effectiveness study—referenced in the block quote above—was prepared by the Commission's Energy Division (under contract with Energy and Environmental Economics, Inc. (E3)), and was issued on October 28, 2013 (E3 Study).[9] It focuses on net energy metering (NEM) customers, and is relevant to this rate proposal given that over 97% of all Option R accounts are also subscribed to NEM.

C. <u>SCE's Proposal: Option R Design</u>

SCE's proposed design for Option R is as follows:

i. The eligibility requirements for Option R, and the 150 MW program cap (discussed in Section II.D.), shall remain unchanged. General eligibility requirements include the following: Option R customers must have demands greater than 20 kW but not exceeding four MW; they must employ Renewable Distributed Generation Technologies; and they must install, own, or operate an eligible onsite Renewable Distributed Generation Technologies system with a net capacity that is 15 percent or greater than the customer's annual peak demand. As is the case under the current Option R tariffs, customers with multiple onsite generation units associated with a single service account, where one or more of the generators is a non-renewable generating unit, are not eligible for the Option R schedules.

ii. Option R will continue to be offered to existing customers currently taking service on Option R in Schedules TOU-8, TOU-GS-3 and TOU-GS-2, and shall be structured to recover all generation-related capacity costs through volumetric energy charges on a cent per kWh basis. The distribution component of the Facilities-Related Demand (FRD) Charge will be modified to reflect both the distribution and transmission offsets, as determined in the study detailed in Appendix C, and shall be set at the following levels, relative to Option B: 82 percent of the TOU-GS-2 distribution FRD, 55 percent of the TOU-GS-3 distribution FRD, 88 percent of the TOU-8-Secondary distribution FRD, 69 percent of the TOU-8-Primary distribution FRD, and 53 percent of the TOU-8-Subtranmission distribution FRD. The revenue deficiency

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9 *See* "California Net Energy Metering Ratepayer Impacts Evaluation" (hereinafter "E3 Study"), *available at http://www.cpuc.ca.gov/NR/rdonlyres/D74C5457-B6D9-40F4-8584-60D4AB756211/0/NEMReportwithAppendices.pdf*

resulting from the discounted FRD charge shall be recovered within each Option R rate schedule by a non-time differentiated cent per kWh volumetric charge. FERC-jurisdictional transmission-related demand charges shall not be modified. Thus, as in the existing Option R rate design, SCE proposes to reflect transmission demand charge adjustments in the distribution demand charge factor.

SCE's proposal to modify Option R rates, while still retaining the cap, draws on three different studies. First, whereas earlier Option R studies focused almost exclusively on the diversity benefit attributable to PV installation, SCE expanded the scope of its original 2011 Study (discussed below and in Appendix C). Second, SCE relies on the compelling conclusions presented in the E3 Study. Third, consistent with formulas summarized in the E3 Study, SCE conducted its own cost-benefit analysis of solar PV installations by evaluating the utility's avoided costs and the estimated bill reductions associated with both NEM and, in particular, Option R.

SCE's Option R rate design study (the first study mentioned in the previous paragraph, which is described in more detail in Appendix C), differed from the 2011 Study in the following key ways. First, the study's solar sample set was expanded to include all current Option R customers in various rate classes. Second, the study included and quantified a new "cost attribute" (or source of costs) to more accurately determine the distribution adjustment factor, namely, the sum of non-coincident peak demands (NCPDs). Third, the study analyzed rate class-specific distribution and transmission adjustment factors. Further details regarding this updated study are discussed below.

Using load data from 2012, SCE conducted a study of the impact of solar installations on distribution and transmission load diversity and cost drivers by evaluating Effective Demand Factors (EDFs),[10] non-coincident peak demands (NCPDs), and demands coincident with the twelve monthly system

[10] EDF is the ratio of a customer's contribution to the peak load on a distribution circuit to the customer's annual non-coincident peak demand. EDFs vary by type of customer and by the voltage level of the circuit.

peaks (12-CP) of the solar populations[11] in the TOU-GS-2, TOU-GS-3, and TOU-8 rate groups,[12] and compared those metrics to the same load attributes of the general population in each respective rate class.

1. Generation Capacity Costs

As in the existing Option R rate design, all generation capacity costs will be recovered through volumetric energy charges on a cents per kWh basis in a manner that maintains the same time-of-use (TOU) allocation of generation capacity revenue recovery.

2. Transmission Capacity Costs

Transmission capacity costs are driven by system peak demand. SCE's current FERC-regulated demand charges are allocated on the basis of 12 monthly Coincident Peak (12-CP) demands. As such, SCE proposes to continue to use the current methodology of evaluating the impact of solar installation on transmission capacity costs by comparing the solar population's 12-CP with the overall population's 12-CP. SCE calculates the difference between the solar population's demand for each month's system peak relative to the overall population, and then averages the relative differences for all 12 months, SCE's proposed adjustments and transmission-related demand charge factors for Option R are shown in Table II-1. Because transmission charges are set by FERC rate cases, the proposed adjustments shall be reflected in the distribution-related factor discussed in the following section.

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[11] Solar population is defined as all customers with PV installations as of January 1, 2012, who have both delivered and received energy measured registered as of December 2012.

[12] SCE's study combined the TOU-8-Subtransmission (Sub) with TOU-8-Primary because there was only one solar TOU-8-Sub customer as of 2012.

Table II-1
Proposed Transmission Demand Factors by Rate Group

Rate Class	Proposed Transmission Demand Charge Adjustment	Proposed Transmission Demand Charge Factor
A	**B**	**C = 1+B**
GS-2	5%	100%*
TOU-GS-3	-26%	74%
TOU-8-SEC	-3%	97%
TOU-8-PRI	-19%	81%
TOU-8-SUB	-19%	81%

*Adjustment capped at 0%, such that Transmission Demand Charge Factor does not exceed 100%

3. Distribution Design Demand Costs

Distribution design demand costs are driven by customers' non-coincident peak demands at the non-ISO transmission, primary, and secondary distribution levels. In the current Option R rate design, SCE uses the EDF load attribute to calculate an offset for the distribution demand charges given that EDF represents a rate class's contribution to the peak demand of a typical circuit relative to the class's own non-coincident peak demands. However, the EDF accounts only for the impact of solar installation on the diversity of load on the typical circuit, which does not provide a full perspective on the *marginal cost* impact of solar installations on a typical circuit. In order to calculate a more appropriate marginal cost offset for Option R distribution demand charges, SCE must also consider the impact of solar installation on distribution design demand costs by including the solar customers' non-coincident peak demands. To do so, SCE proposes using the product of the NCPD and EDF as the metric to calculate a suitable offset for the Option R distribution demand charge. This formula is consistent with the primary cost attribute that SCE already uses to allocate revenue requirements for distribution facilities-related charges in all of SCE's retail rates, as this attribute incorporates both the billing determinant cost driver and the rate class's contribution to the distribution circuit peak demand. Thus, applying the product of NCPD and EDF to the Option R rate is appropriate, and moves the Option R rate design closer to a cost-based rate design.[13] SCE then calculates the difference between the solar population's NCPD-adjusted EDF relative to the overall population for each rate group, which results in the proposed distribution-related Option R factors shown in Table II-2 below.

Table II-2
Distribution Load Attributes
and Proposed Demand Factors by Rate Group

Rate Class		NCPD (kW/Customer)	12 kV EDF	EDF adjusted for NCPD	Distribution FRD adjustment	Transmission FRD adjustment (Table II-1, Col. C)	Proposed Distribution Demand Charge Adjustment	Proposed Distribution Demand Charge Factor
A	B	C	D	E = C*D	F = E (solar) / E (Overall)	G	H	I = 1+H
GS-2	Solar	69.67	0.35	24.38	-18%	0%*	-18%	82%
	Overall	49.02	0.61	29.90				
TOU-GS-3	Solar	318.19	0.42	133.64	-39%	-26%	-45%	55%
	Overall	315.00	0.69	217.35				
TOU-8-SEC	Solar	917.65	0.62	568.94	-11%	-3%	-12%	88%
	Overall	865.14	0.74	640.20				
TOU-8-PRI	Solar	1648.14	0.62	1021.85	-25%	-19%	-31%	69%
	Overall	1954.91	0.70	1368.44				
TOU-8-SUB	Solar				-25%	-19%	-47%	53%

*For GS-2 customers, the transmission FRD adjustment measured value is 5%, as seen in Table II-1. However, because it is capped at 0%, the proposed distribution demand charge factor reflects a transmission FRD adjustment of 0%.

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13 SCE will, however, continue to review the E3 Study, and the characteristics of existing Option R customers, from the perspective of possibly treating Option R as a separate rate class for revenue allocation and rate design. That would bring the rate structure closer to cost-based rates than what has been accomplished modestly in this RDW proposal.

The basic structure of Option R is not being modified in this proposal to the extent that it is still premised on the transfer of fixed cost recovery to volumetric energy charges. Thus, even taking into account the factor adjustments described in the previous sections, the impact on average rates for customers currently on Option R is modest (less than 2.5%, as evidenced in Table II-3 below). In fact, TOU-GS-3-R customers' average rate under the proposed Option R would be 1% lower than it is under the current Option R.

Table II-3
Average Rates Comparison

Rate Group	Average Rates ¢/kWh				% Impact Proposed R
	Option B	Option A	Current R	Proposed R	vs. Current R
GS-2	19.7	17.9	17.1	17.5	2.44%
GS-3	19.1	17.6	16.7	16.5	(1.03%)
TOU-8-Sec	16.5	15.2	14.7	14.8	1.14%
TOU-8-Pri and TOU-8-Sub	14.1	13.0	12.7	12.9	1.81%

D. SCE's Proposal: Option R Cap

SCE proposes to maintain the 150 MW cap on Option R, which has been in effect ever since this optional rate was first adopted by the Commission in 2009. Because the cap has already been met, SCE has closed the Option R rate to new customers, while continuing to allow existing customers to take service on Option R provided that they do not increase their system capacity.[14] SCE's proposal to preserve the 150 MW cap is justified notwithstanding the design updates to the rate as described in Section II.C. This is owing (in part) to the E3 Study's stark conclusions, corroborated by a complementary study undertaken by SCE, that solar subsidies in the NEM program result in significant cost-shifting to non-participating ratepayers. The E3 Study, which was required by Assembly Bill 2514 (Bradford, 2012) and D.12-05-036, examined the costs and benefits of serving customers who install solar, including Option R customers. The Commission's stated goal in ordering the E3 Study was to "provide the Commission and all interested parties, including the Legislature, with a better understanding of who benefits, and who bears the economic

[14] SCE notified interested parties of the progression toward the 150 MW cap by posting regular update on its website, and by sending outbound communications about this issue to solar contractors.

burden, if any, of the NEM [Net Energy Metering] program."[15] The E3 Study concluded that, for non-residential NEM customers, the cost shift amounted to $70 million as of 2012, and could increase to $299 million assuming full NEM subscription.[16] Those statistics compel prudence with respect to promoting or expanding any rate option that necessarily exacerbates or contributes to cost-shifting because "[e]very dollar of bill savings received by . . . customers is a direct reduction in revenues. Since rates are adjusted over time such that utilities meet their revenue requirement, this revenue reduction will be made [up] by ratepayers. The bill savings are thus a direct cost to ratepayers."[17]

With respect to the proper formula for quantifying the cost-shift, Chapter 4.1 of the E3 Study explains:

> To the extent that the bill reductions attributed to NEM exceed offsetting benefits, there is a cost shifting from NEM customers to other utility ratepayers. Therefore, the net cost of NEM to ratepayers is the sum of ratepayer costs (bill savings, incremental billing costs, and integration costs) less ratepayer benefits (avoided costs).[18]

With this formula in mind, SCE undertook its own cost-benefit analysis[19] of distributed solar generators and the NEM program, and also examined systemic cost-shifts resulting from Option R and Option A rates for non-residential customers.[20] In SCE's analysis, non-residential Option B NEM customers create a $49 annual cost shift to non-participating customers per each kilowatt of installed generator name plate capacity. This is due to solar generation and NEM alone, all other things being equal (*i.e.*, the NEM customer is still on the default Option B rate). The $49-per-1-kW figure is derived by calculating NEM customers' bill savings compared to their otherwise applicable tariff (OAT) rate, and then

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[15] D.12-05-036, p. 14.

[16] E3 Study, p. 7.

[17] *Id.*, p. 41.

[18] *Id.*, p. 38.

[19] Based on the "NEM All Generation" cost-benefit analysis presented in Chapter 4 of the E3 Study, SCE conducted its own non-participant cost-benefit analysis using bill savings calculations and avoided energy costs.

[20] Like Option R rates, Option A collects all generation capacity costs through volumetric energy charges, but maintains the Option B structure for transmission and distribution capacity costs recovery.

subtracting the avoided costs to SCE attributable to the installation of the solar generator. This figure is arguably conservative because it assumes that the customer took service, and continues to take service, on an Option B schedule, which recovers all generation, transmission, and distribution capacity costs through time - and facilities- related demand charges—charges that are not avoided with the installation of a distributed generation system. If the customer installs solar generation and, in addition, transfers from an Option B rate to an Option A rate, which recovers all generation capacity costs through volumetric energy charges, the customer is effectively able to bypass a large portion of the generation capacity costs because the solar generation allows them to avoid some of the on-peak energy charges. The resulting cost-shift to non-participants increases from $49 per kW-year to $122 per kW-year for each kW installed on Option A versus Option B.[21] This cost shift is further exacerbated if the solar generation customer transfers from an Option B rate to an Option R rate, because they avoid paying portions of the generation, distribution, and transmission capacity costs. When an NEM customer moves from Option B to Option R, this results in a cost shift to non-participants of $142 per 1 kW, a cost-shift that is 200% greater than the cost-shift associated with an NEM customer on Option B. Because NEM and other solar installations already cause a substantial cost-shift to customers without onsite generation, and, as discussed above, because solar customer participation on Option R only increases the cost-shift, SCE proposes that the Option R program remain closed to new participants and should not be expanded. Appendix D provides Option R bill impacts under various scenarios. As the Commission already concluded in D.11-12-053 (decision in Pacific Gas and Electric Company's 2011 Phase 2 proceeding) "solar customers on net metering are currently receiving enough compensation for the costs they allow the utility to avoid." Stated differently, an Option R subsidy on top of an NEM subsidy adds nothing to the utility's avoided cost benefits.

NEM subsidies currently in place, even *absent* the availability of Options A and R, provide sufficient incentives for customers to install solar. This is demonstrated by the popularity of solar installation among non-residential customers in the PG&E service territory even though PG&E does not

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[21] As noted In Section II.B above, revisiting the 50-MW Option A cap was not part of the 2012 GRC Phase 2 settlement agreement.

offer an Option R-type solar rate. PG&E's solar adoption rate has historically exceeded SCE's, as evidenced in Table II-4 below. Thus, SCE's proposal in this RDW to maintain the cap on Option R is reasonable.

Table II-4
SCE and PG&E Non-Residential Cumulative Installed Solar Capacity[22]

Year	SCE (MW)	PG&E (MW)
2007	7.1	5.3
2008	44.9	46.2
2009	67	94.2
2010	88.8	138.5
2011	147.1	223.6
2012	237.6	328.8
2013	283.2	413.3

Finally, the Commission should not expand the cap on a rate like Option R given the many moving parts in the wider regulatory discussions surrounding NEM grandfathering, prompted by the Legislature's passage of AB 327. This is especially true given the impact of the subsidies on non-participating customers, and the unknown but important changes in the future between the NEM program's subsidies and future program design, which is required to be revisited by December 31, 2015.[23]

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[22] Data retrieved from www.californiasolarstatistics.ca.gov on December 12, 2013.

[23] See PU Code 2827.1(b) per AB 327 (Perea-2013).

III.

RATE PROPOSALS FOR EV[24] CUSTOMERS

A. Summary of EV Rate Proposals

For residential customers, SCE currently has two EV-specific optional rate schedules: (1) TOU-EV-1, a non-tiered TOU rate for customers who separately meter their EV charging; and (2) TOU-D-TEV, a whole-house (one meter) TOU rate comprised of two inclining-block usage tiers. In this RDW, SCE proposes to make the following changes to these rate schedules, most of which derive from Commission directives outlined in Section III.B below:

- **Schedule TOU-EV-1**: (a) Add a new monthly meter charge to recover the costs of the separate meter; and (b) change the summer season—currently defined as May 1 to November 1—to be consistent with summer season for other residential rate schedules, which is June 1 to October 1.
- **Schedule TOU-D-TEV**: Close this schedule, and migrate the customers to a newly created, non-tiered rate called Schedule TOU-D. In addition to eliminating the tiers, Schedule TOU-D will differ from Schedule TOU-D-TEV in the following ways: (a) the on-peak period will be from 2 p.m. to 8 p.m. on non-holiday weekdays (instead of 10 a.m. to 6 p.m.); (b) the super off-peak period will be extended to 10 hours, every day from 10:00 p.m. to 8:00 a.m. (instead of midnight to 6:00 a.m.); and (c) the new rate schedule will be open to all residential customers, not just those who own EVs.[25] The new Schedule TOU-D will have an "Option A," designed for lower usage customers, and an "Option B" designed for higher usage customers, with an ability for customers to switch between options as their usage patterns change. Option A customers will receive a baseline credit allowance and will pay a customer charge that correlates with whatever the customer charge is for Schedule D (SCE's default residential schedule). Option B customers

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[24] Unless otherwise stated herein, the reference to "EV" includes both plug-in hybrid electric vehicles (PHEVs) and battery electric vehicles (BEVs).

[25] The definition of the summer season for the new Schedule TOU-D will be the same as it is for Schedule TOU-D-TEV, which, consistent with the proposed change to Schedule TOU-EV-1, will be defined as June 1 to October 1.

will not have a baseline credit allowance, and the customer charge is proposed to be substantially higher than the customer charge for Option A customers.

As described more fully below, SCE's innovative proposal for Schedule TOU-D comports with the Commission's "goal of a single meter Electric Vehicle rate design [that is] structure[d] [as] a simpler, cost-based, time-of-use rate that bypasses the disincentives for Electric Vehicle use associated with tiered rates but still recover, at a minimum, the incremental cost to serve Electric Vehicles."[26]

For commercial customers, SCE also has EV-specific rate schedules, and does not propose to modify them in this RDW with the exception of revising Schedule TOU-EV-3 to permit these customers to benefit from Schedule TOU-EV-4's demand charge structure, which could potentially limit overall demand charges for the customers.

B. Regulatory Background and Compliance Mandate

The Alternative Fuel Vehicle Order Instituting Rulemaking (AFV OIR)[27] was initiated in 2009 to explore the complex issues surrounding EV adoption and integration with the electric grid. The AFV OIR, now continuing in a new rulemaking (R.13-11-007), afforded an opportunity to study rates and tariffs as the market for light duty EVs emerged, and as stakeholders began to better understand how changes in customer behavior impact utility infrastructure. In a decision from Phase 2 of the 2009 AFV OIR, D.11-07-029, the Commission ordered California's investor- owned utilities (IOUs) to study a number of factors relevant to EV ratemaking, and to modify their EV tariffs based on an analysis of load data and customer behavior under existing tariffs. Specifically, the Commission ordered SCE to do as follows:

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[26] D.11-07-029, p. 76, Finding of Fact # 2.

[27] Rulemaking (R.) 09-08-009.

> Southern California Edison Company shall file plug-in hybrid and electric vehicle rate design proposals in Rate Design Window applications in 2013 as provided for and in accordance with the schedule in Decision 89-01-040. These plug-in hybrid and electric vehicle rate design proposals shall include an analysis of plug-in hybrid and Electric Vehicles charging load profiles, the costs and benefits of plug-in hybrid and electric vehicle integration and charging, and consumer responses to plug-in hybrid and Electric Vehicles time-of-use price differentials. These rate design proposals shall also include an evaluation of the feasibility and benefits of plugin hybrid and electric vehicle demand charges in the residential and commercial context.[28]

SCE describes its residential and commercial EV rate proposals in detail in Section III.C below. Appendices G through J provide back-up information regarding EV customers' charging load profiles, the costs and benefits of EV integration and charging, consumer responses to TOU price differentials, and the feasibility of assessing demand charges. The following is a summary of the conclusions from these appendices:

- *Load profiles* (Appendix G)*:* Once EV customers opt in to a TOU rate, their usage behavior demonstrates consistent and rational responsiveness to price signals (*i.e.*, off-peak and super off-peak battery charging). The EV customers' load profiles support SCE's decision to expand the super-off peak period to support Level 1 charging (120v), which is consistent with recent comments filed by General Motors in R.13-11-007, namely, that "customers should be properly rewarded (*i.e.*, not penalized) for using Level 1 [charging] by expanding TOU windows to account for a normal commute."[29]
- *Costs and benefits of EV integration and charging* (Appendix H): Although SCE believes there may be incremental marginal costs associated with EV adoption in the future as some customers might adopt higher charging levels, at this point the cost data does not indicate a need for special rate treatment, including the addition of demand charges, for residential EV customers to distinguish the costs of serving EV loads from those of other equipment. Furthermore, although the market for EV adoption is still considered nascent, there are efforts underway to quantify the

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[28] D.11-07-029, Ordering Paragraph (OP) #3.

[29] Opening Comments of General Motors On The Order Instituting Rulemaking To Consider Alternative-Fueled Vehicle Programs, Tariffs and Policies, p. 10, filed December 13, 2013.

benefits of EV load on the grid, assuming appropriate charging behavior (*i.e.*, that vehicles charge during generally off-peak periods when the marginal cost of generation is low). More substantial environmental benefits of EV integration is contingent on customers responding to appropriate cost-based price signals to incentivize charging during cheaper super off-peak time periods.

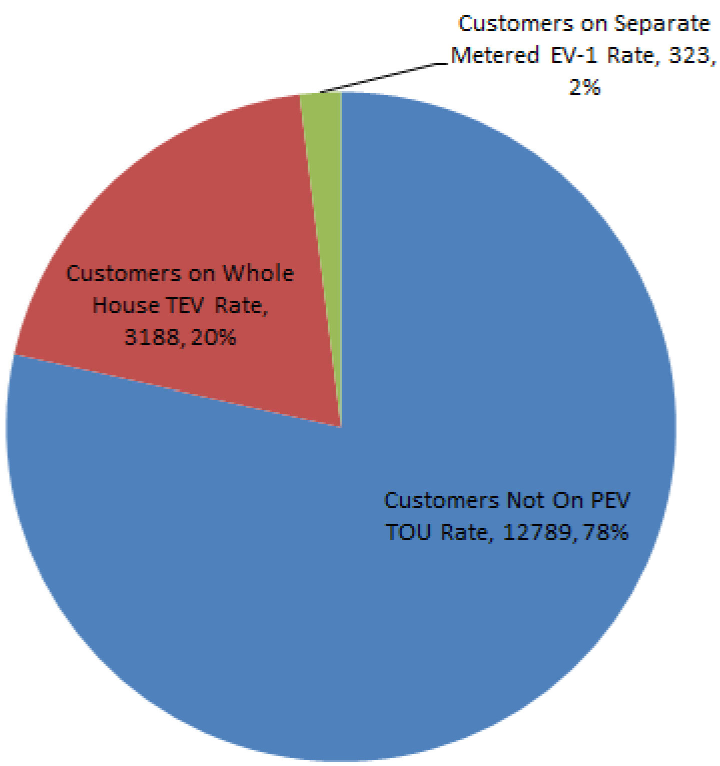
- *Consumer responses to price differentials* (Appendix I): EV customers who take service on TOU rates respond well to cost-based TOU price signals. Most EV customers, however, elect to remain on the standard (default) Schedule D rate and are not receiving TOU price signals. In order to encourage adoption of TOU rates, these rates must be kept simple and understandable. The rates must also provide flexibility for both lower and higher usage customers.
- *Demand charges* (Appendix J): Demand charges are not appropriate for residential customers at this time given the immaterial measured impact of EV load on the system. For commercial customers, however, SCE proposes to make the Facilities Related Demand (FRD) Charges consistent between the two commercial EV rate schedules that are currently being offered, as described in Section III.E below.

Beyond meeting the compliance requirements from D.11-07-029, SCE endeavors in this RDW to leverage the proposed Schedule TOU-D, Option B in service of additional goals applicable to a broader customer base than just EV owners. In particular, as described in the next section, an opt-in TOU residential rate that is non-tiered will provide appropriate price signals to high-usage customers who are willing and able to shift their load from the high-cost on-peak period to the lower-cost off-peak period.

C. <u>Policy Considerations and Rate Design Objectives</u>

SCE aims to design simple and easy-to-understand TOU rates that will incentivize price-responsive load-shifting behavior from customers with EVs. As of October 31, 2013, SCE had estimated that only approximately one-fifth of residential EV owners elected to switch to an optional TOU schedule instead of remaining on the default, non-TOU residential tiered rate (Schedule D). Figure III-1 below depicts the estimated number and percentage of EV customers taking service on each type of rate.

Figure III-1
EV Owners' Rate Elections



That means that approximately 80 percent of residential EV customers are not receiving cost-based price signals to encourage vehicle charging at times that are most optimal for the electric grid. In developing EV rates, SCE endeavored to design cost-based rates that (1) are simple and understandable, (2) provide cost-based price signals that encourage off-peak charging, (3) provide a reasonably long super off-peak charging period to accommodate Level 1 charging, while at the same time keeping on-and off-peak rates reasonably attractive to current and potential EV owners, and (4) are suitable for both lower usage and higher usage customers.

SCE's agrees with the Commission's findings in the AFV OIR that tiered TOU rates are unnecessarily complex and difficult to explain to customers. In order to improve TOU rate adoption by EV customers, SCE is proposing to replace the current tiered Schedule TOU-D-TEV rate with a simpler, non-tiered TOU rate option that should be more understandable to customers.[30] The longer super off-peak period in the new rate designs should also make the rates more attractive to EV customers with Level 1 chargers.

While the main purpose of this RDW is to propose revisions to EV rates, to the extent the design of residential whole-house EV rates could also benefit a subset of residential customers (other than EV owners) who are ready and willing to shift load out of the high-cost on-peak period in response to more cost-based TOU signals, SCE sees no reason why the rate should not also be made available to those customers. This is particularly true in the absence of an established and cost-effective way to verify and track EV ownership.[31] Stated differently, the Commission's policy direction in D.11-07-029, although issued in the EV context, applies equally to the context of high-usage residential customers considering opt-in rates. Specifically, SCE can take its research into customer load profiles, customer responses to TOU price signals, and the Commission's decision to order the inclusion of a fixed charge for metering and the elimination of tiered rates, and use all of these factors to support an opt-in residential rate that focuses on load profiles and price-responsive behaviors instead of just vehicle ownership.

D. Residential EV Rate Proposals

1. Schedule TOU-EV-1

Customers on Schedule TOU-EV-1 use a separate meter to measure EV charging. It is a two-period, non-tiered TOU rate that offers discounted off-peak charging. SCE proposes to introduce two changes to this rate. First, SCE seeks authorization to institute a recurring, fixed monthly charge designed to recover only the cost of the second meter. This proposal accords with the Commission's conclusion that "if the individual utility customer chooses a separate metering option to obtain a particular Electric Vehicle

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30 SCE currently offers a tiered TOU rate for domestic customers, Schedule TOU-D-T, and SCE does not propose in this RDW to supplant it with Schedule TOU-D. However, higher usage residential customers interested in being served on a TOU rate may prefer Schedule TOU-D because it is simpler and less confusing than Schedule TOU-D-T, which is a two-tiered TOU rate. SCE's Schedule TOU-D Option A employs a baseline credit, which is similar to the structure proposed by the Office of Ratepayer Advocates in its May 29, 2013 filing in R.12-06-013.

31 SCE does not currently require proof of EV ownership for a customer to be eligible for an EV rate (*e.g.*, proof of vehicle registration, a Vehicle Identification Number, etc.), but does inquire with customers about when they expect to take delivery of their electric vehicle.

rate, the customer (rather than all ratepayers) should bear the cost of the separate meter."[32] The proposed meter charge will be based on the meter component of the customer marginal costs adopted in Phase 2 of SCE's last General Rate Case. SCE will set the TOU-EV-1 monthly meter charge at the full Equal Percent Marginal Cost (EPMC) level.

Table III-5
Current[33] vs. Proposed Schedule TOU-EV-1 Rates

Periods	Current (¢/kWh)	Proposed (¢/kWh)
S. On-Peak	33.0	33.8
S. Off-Peak	10.6	11.6
W. On-Peak	22.6	20.9
W. Off-Peak	10.9	11.1
Basic Charge ($/month)		$2.64

Second, SCE will maintain the current (two) time-of-use periods for Schedule TOU-EV-1, but proposes to adjust the seasons in which they apply to make them consistent with the season definitions in the other residential rate schedules. Thus, the summer season for Schedule TOU-EV-1 is proposed to be June 1 to October 1 (instead of May 1 to November 1). This modification will improve the simplicity and understandability of this rate for customers who may consider and compare the separately metered option to other domestic rate schedules.

Table III-6
Current vs. Proposed Time-of-Use Periods (Schedule TOU-EV-1)

Periods	Current	Proposed
Summer	May 1st - October 31st	June 1st - September 30th
Winter	November 1st - April 30th	October 1st - May 31st
On-Peak	12pm - 9pm, everyday	12pm - 9pm, everyday
Off-Peak	All other hours	All other hours

[32] D.11-07-029, p. 48.

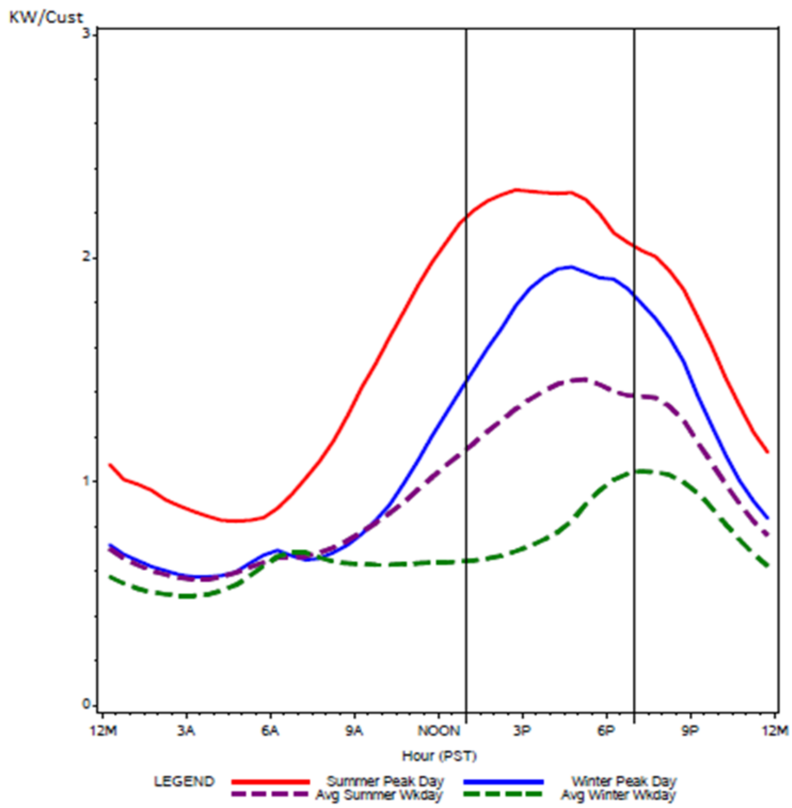
[33] Unless otherwise stated, to the extent the comparison tables for EV rates in this filing refer to "current" rates, SCE is using its revenue requirement as of October 2013.

2. New Schedule TOU-D

SCE proposes to close its current (tiered) whole-house EV rate schedule (TOU-TEV) and replace it with a new rate schedule, TOU-D, which will have an Option A for lower-usage customers, and an Option B for higher-usage customers (described below). SCE intends to migrate customers from Schedule TOU-TEV to Schedule TOU-D after educating them about the usage-based options (A or B) in Schedule TOU-D and describing the savings that could be obtained under those rates assuming no change in usage. Schedule TOU-D will be non-tiered, and will differ from Schedule TOU-TEV in several additional ways.

First, the on-peak period will be 2:00 p.m. to 8:00 p.m. on non-holiday weekdays (instead of 10:00 a.m. to 6:00 p.m.). It is reasonable to reduce the on-peak window by two hours and shift it to later in the day because the latter part of the newly proposed on-peak window better aligns with SCE's future system-wide generation peak (because of the 33 percent RPS requirement), and also aligns with SCE's current residential peak usage. Figure III-2 below depicts the current residential peak.

Figure III-2
2012 Domestic Load Profiles – Seasonal Peak and Average Workdays



Moreover, AB 327 allows the Commission to order default TOU rates for residential customers beginning in 2018, and it is prudent to begin now (with several years of lead time) on TOU rates that designate the appropriate on-peak window to which customers can begin becoming accustomed.

Second, SCE proposes to retain super off-peak rates, but will (a) expand the window by four hours; and (b) shift the super off-peak period to 10 p.m. to 8 a.m. (instead of midnight to 6 a.m.).[34] This proposal is designed to make charging easier for, and more attractive to, customers with Level 1 chargers without disadvantaging customers with vehicles that charge at higher voltages. It is also guided by load research (of Schedule TOU-TEV customers) showing predictable and positive load-shifting behavior of EV customers on TOU rates.

[34] The balance of the hours will comprise the off-peak period.

Third, Schedule TOU-D will be open to all residential customers, not just those who own EVs, for the reasons stated in Section III.C.

Table III-7 summarizes the proposed on-peak, off-peak and super-off peak periods.[35]

Table III-7
Current TOU-D-TEV vs. Proposed TOU-D Time-of-Use Periods

Periods	Current TOU-D-TEV	Proposed TOU-D
On-Peak	10am - 6pm, weekdays except holidays	2pm - 8pm, weekdays except holidays
Super-Off-Peak	12am - 6am, everyday	10pm - 8am, everyday
Off-Peak	All other hours - all year, everyday	All other hours - all year, everyday

a) TOU-D-Option A (Lower Usage Customers)

Option A of the new Schedule TOU-D is designed with lower-usage customers in mind, and is intended to make the TOU rate competitive with the default residential rate (Schedule D) while still remaining true to cost-to-serve principles. Customers on this option will pay a customer charge commensurate with the customer charge then in place for customers taking service on Schedule D (SCE's default residential rate), a feature that is consistent with recently passed legislation mandating that IOUs offer "at least one optional time-variant rate" that has a customer charge subject to the same restrictions applicable to the default residential rate.[36]

Although Schedule TOU-D will not be tiered, customers on Option A will receive a "baseline credit" derived by multiplying the baseline quantity (in kWh) that the customer would have received had they been served that month on Schedule D[37] by the difference (in cents) between the residential non-CARE average rate and the Tier 1 rate under Schedule D. SCE then calculates a revenue-

35 Schedule TOU-D will have the same seasonal definition as the other residential rate schedules, in which the summer will be defined as June 1 to October 1.

36 Public Utilities Code Section 739.9(f).

37 In no event would the customer receive a credit based on kilowatt hours that exceed the Tier 1 allowance for the customer had it been on Schedule D. Should the customer use fewer kWh than its Tier 1 baseline allowance under Schedule D, the baseline credit under Schedule TOU-D will be based on the actual kWh consumed using the credit formula described above.

neutral rate design taking the baseline credits into account, which results in the baseline credit revenue deficiency being allocated to the on- and off-peak periods on an equal cents-per-kilowatt hour basis.

With the exception of these two rate characteristics (a customer charge equal to what Schedule D customers pay, and a baseline credit), Option A will be designed the same as Option B, including marginal cost floor pricing for the super-off peak period and summer on-peak rates that are reduced by recovering some summer season generation costs in the winter (as SCE has done for its small commercial customer TOU rate structure).

b) <u>TOU-D-Option B (Higher Usage Customers)</u>

Option B is designed for higher usage customers, including but not limited to current EV owners. The super off-peak rates will be subject to a floor price defined as the sum of SCE's marginal generation (energy and capacity), distribution and transmission costs, plus non-bypassable charges. SCE will adjust the generation revenue requirement such that 25% of the summer on-peak generation costs will be transferred to the winter on-peak generation energy charge. This structure reduces the price differentiation between summer and winter on-peak periods, thus mitigating seasonal bill volatility. SCE proposes to increase the fixed customer charge to approximately full customer marginal cost levels. The benefit of incorporating a higher fixed charge in the TOU-D Option B rate design is the ability to reduce upward pressure on the distribution energy charge in all TOU periods, and provide increased bill stability to the target customers who are generally higher usage customers.

Table III-8
Proposed TOU-D Rates (Option A & Option B)

Period	TOU-D-Option A (¢/kWh)	TOU-D-Option B (¢/kWh)
S. On-Peak	40.2	33.9
S. Off-Peak	24.6	18.2
S. Super-Off-Peak	10.9	10.9
W. On-Peak	28.0	21.7
W. Off-Peak	21.3	14.9
W. Super-Off-Peak	10.9	10.9
Baseline Credit (¢/kWh)	(3.8)	
Basic Charge ($/month)	$0.91	$16

c) Switching Between Options A and B

Most of SCE's customers are subject to Rule 12.D's twelve-month residency requirement, meaning that they cannot change to an optional tariff more frequently than once every twelve months. SCE proposes to create an exception to this requirement for customers wishing to move from Option B to Option A or vice versa, or who wish to move from one of these optional rates back to Schedule D. This proposal is reasonable as a means of sensitizing EV customers to different optional rates depending on their usage patterns and consumption levels without locking them into their first rate election. This is critical given that the impact of new EV loads on electric bills may not be apparent to customers who are new to the technology. A similar exception to Rule 12 was previously adopted by the Commission in Schedules TOU-D-1 and TOU-D-2 at a time when TOU metering was not prevalent in the residential market, making pre-adoption rate analyses close to impossible.

3. Bill Impacts

SCE designed both Option A and Option B of the proposed Schedule TOU-D to be revenue neutral to SCE's default domestic rate (Schedule D). The bill impact tables below (Table III-9, Table III-10, and Table III-11), show how Option A and Option B rates compare to SCE's Schedule D rate not as it currently defined, but as SCE proposes it be modified in R.12-06-013 (the residential rate design OIR) starting June 2014, *i.e.*, a three-tiered rate with moderated differentials between tiers. That future-state

Schedule D is labeled in the bill impact tables as "3-Tier Schedule D." Histograms of these tables, showing additional bill impacts, are provided in Appendix F.

First, Table III-9 below illustrates the difference in bills between a representative sample of residential customers (not just those with EVs) on the default residential rate (Schedule D) versus Option A of the proposed Schedule TOU-D, which is designed with lower usage (under 700 kWh per month) customers in mind. This table demonstrates modest bill changes for lower usage customers transitioning from Schedule D to Option A. The comparison in the table assumes no behavioral changes in the residential sample; thus, the average rate of these customers could be expected to be lower should the TOU rate incentivize load-shifting to the super off-peak period.

Table III-9
Bill Impacts: 3-Tier Schedule D vs. Schedule TOU-D Option A

% Impact	Customer		Average					Cents/kWh		%	Monthly $		Average
3-Tier D Vs. TOU-D Option A	**Number**	**% Customer**	**Monthly - kWh**	**% On**	**% Off**	**% Super Off**	**Bill Days**	**3-Tier D**	**TOU-D Option A**	**Change**	**3-Tier D**	**TOU-D Option A**	**Monthly $ Change**
LE 100	87,365	3.0%	61	18.2%	43.1%	38.7%	283	17.2	17.5	1.3%	$ 10.5	$ 10.7	$ 0.1
100 to 300	579,619	20.1%	214	19.2%	45.9%	33.7%	325	16.4	17.1	4.4%	$ 35.1	$ 36.7	$ 1.6
300 to 500	758,759	26.4%	390	19.9%	45.7%	24.1%	319	17.1	17.9	4.8%	$ 66.6	$ 69.8	$ 3.2
500 to 700	643,913	22.4%	593	20.8%	46.1%	18.7%	320	18.3	19.0	3.9%	$ 108.3	$ 112.5	$ 4.2
700 to 900	366,857	12.7%	792	22.1%	46.8%	13.3%	314	19.4	19.9	2.5%	$ 153.5	$ 157.3	$ 3.8
900 to 1100	226,375	7.9%	977	22.2%	47.1%	13.4%	320	20.2	20.3	0.4%	$ 197.1	$ 197.9	$ 0.8
1100 to 1300	86,941	3.0%	1,192	21.3%	47.3%	10.1%	324	20.9	20.2	-3.1%	$ 249.1	$ 241.3	$ (7.8)
1300 to 1500	66,210	2.3%	1,394	22.3%	47.8%	13.9%	314	21.5	20.7	-3.8%	$ 299.6	$ 288.1	$ (11.5)
GE 1500	63,273	2.2%	2,201	22.3%	45.6%	19.8%	332	22.6	20.5	-9.0%	$ 496.5	$ 452.0	$ (44.5)
Total	2,879,313	100%	576	21%	46%	30%	319	**19.07**	**19.26**	**1.0%**	**$ 109.9**	**$ 111.0**	**$ 1.1**

Second, Table III-10 below illustrates the difference in bills between the same representative sample of residential customers (*i.e.*, not just those with EVs) on Schedule D versus Option B of the proposed Schedule TOU-D, which is designed with higher-usage customers in mind. This table demonstrates higher bill savings for higher usage customers, even without load-shifting.

Table III-10
Bill Impacts: 3-Tier Schedule D vs. TOU-D Option B

% Impact	Customer		Average					Cents/kWh		%	Monthly $		Average
3-Tier D Vs. TOU-D Option B	Number	% Customer	Monthly - kWh	% On	% Off	% Super Off	Bill Days	3-Tier D	TOU-D Option B	Change	3-Tier D	TOU-D Option B	Monthly $ Change
LE 100	87,365	3.0%	61	18.2%	43.1%	38.7%	283	17.2	42.7	147.7%	$ 10.5	$ 26.1	$ 15.6
100 to 300	579,619	20.1%	214	19.2%	45.9%	33.7%	325	16.4	23.9	45.6%	$ 35.1	$ 51.1	$ 16.0
300 to 500	758,759	26.4%	390	19.9%	45.7%	24.1%	319	17.1	20.7	21.1%	$ 66.6	$ 80.7	$ 14.1
500 to 700	643,913	22.4%	593	20.8%	46.1%	18.7%	320	18.3	19.5	6.9%	$ 108.3	$ 115.7	$ 7.5
700 to 900	366,857	12.7%	792	22.1%	46.8%	13.3%	314	19.4	19.1	-1.3%	$ 153.5	$ 151.5	$ (2.0)
900 to 1100	226,375	7.9%	977	22.2%	47.1%	13.4%	320	20.2	18.9	-6.6%	$ 197.1	$ 184.2	$ (12.9)
1100 to 1300	86,941	3.0%	1,192	21.3%	47.3%	10.1%	324	20.9	18.4	-12.0%	$ 249.1	$ 219.2	$ (30.0)
1300 to 1500	66,210	2.3%	1,394	22.3%	47.8%	13.9%	314	21.5	18.4	-14.6%	$ 299.6	$ 255.9	$ (43.7)
GE 1500	63,273	2.2%	2,201	22.3%	45.6%	19.8%	332	22.6	17.6	-21.8%	$ 496.5	$ 388.3	$ (108.1)
Total	2,879,313	100%	576	21%	46%	30%	319	**19.07**	**19.66**	**3.1%**	**$ 109.9**	**$ 113.3**	**$ 3.4**

SCE also examined in Table III-11 below bill comparisons for SCE's EV customer who are currently on Schedule TOU-D-TEV. In contrast to Table III-9 and Table III-10, the population in the table below consists exclusively of EV owners, who have demonstrated behavioral changes in response to price signals (*i.e.*, vehicle charging in the super off-peak period). This table shows that lower usage EV customers (those on Option A) are marginally better off on Schedule TOU-D than they would be under Schedule D. Higher usage EV customers (those on Option B) are considerably better off on the TOU rate versus Schedule D (with bills 20% lower than Schedule D, and 9% lower than the current Schedule TOU-TEV).

Table III-11
Hypothetical Bill Impacts: Schedule TOU-TEV

Group Usage (kWh)	Number of TEV Customers	% of Population	Average kWh	Three-Tier Schedule D	TEV Rate (Balanced to Three-Tier D)	TOU-D (Option A)	TOU-D (Option B)
<=100	6	0%	148	$ 26	$ 24	$ 24	$ 40
100-300	94	3%	338	$ 57	$ 52	$ 51	$ 67
300-500	423	15%	518	$ 93	$ 83	$ 83	$ 94
500-700	629	22%	704	$ 134	$ 118	$ 116	$ 122
700-900	611	21%	893	$ 179	$ 158	$ 155	$ 153
900-1100	385	14%	1090	$ 227	$ 198	$ 192	$ 183
1100-1300	235	8%	1290	$ 277	$ 241	$ 231	$ 215
1300-1500	160	6%	1495	$ 330	$ 287	$ 274	$ 249
>1500	304	11%	2324	$ 538	$ 468	$ 439	$ 381

4. Treatment of Revenue Deficiencies

Because the proposed Schedule TOU-D rate is more cost-based than the Schedule D rate (which is still constrained by statutory restrictions that have only recently been partially lifted), the migration of customers from Schedule D to Schedule TOU-D has the potential of creating a revenue deficiency. To address this issue, SCE proposes to annually rebalance the Schedule TOU-D rate to be revenue neutral to Schedule D. Any revenue deficiency will be captured in the Conservation Incentive Adjustment (CIA) balancing account, and will be allocated to the entire residential class of customers.[38] In any event, SCE notes that the issue of recovering revenue deficiencies is premature at this time given the low opt-in TOU rate adoption numbers to date.[39]

E. Commercial EV Rate Proposals

SCE currently offers two rate options exclusively for commercial EV customers (Schedules TOU-EV-3 and TOU-EV-4)[40] and does not propose to change them in this RDW with the exception of modifying Schedule TOU-EV-3 to permit customers to take advantage of a demand charge feature available to Schedule TOU-EV-4 customers.

Schedule TOU-EV-4 is applicable to customers who charge EVs on a premises that is served under a demand-metered general service or agricultural account ("host account"), and where a separate meter serves the EV load.[41] For both accounts—the host account, and the EV account—the customer is subject to transmission and distribution Facilities-Related Demand (FRD) Charges, except, to avoid double-charging the customer for demand, the rates are designed such that a customer will never pay its EV account's FRD Charge in a given month if the customer's maximum demand on the host account is higher than the

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38 This proposal is different from the position SCE outlined on page 47 of its Residential Rate Design Proposal filed on May 29, 2013 in R.12-06-013, in which SCE proposed to recover revenue deficiencies resulting from a migration to TOU rates from "residential customers served on below-cost rates."

39 Less than half of one percent of SCE's residential customers have opted in to Schedule TOU-D-T.

40 A government agency taking service for the purpose of charging a zero emissions electric bus may also take service on TOU-GS-1, which is open to a wider customer base than EV customers. SCE does not propose to change TOU-GS-1 in this RDW.

41 Customers can also take service on Schedule TOU-EV-4 at a premises where the only service provided is on Schedule TOU-EV-4.

maximum demand on the EV account. (If the converse is true, *i.e.*, the EV account's maximum demand is higher than the host account's maximum demand, the EV account's FRD Charge would be calculated as the difference between the EV maximum demand and the host account maximum demand only.) This formula is not currently available for Schedule TOU-EV-3 customers who, instead of paying an FRD Charge, pay higher *energy* charges for transmission and distribution.

To bring Schedule TOU-EV-3 more in line with Schedule TOU-EV-4, SCE proposes to modify Schedule TOU-EV-3 to create two options—one in which the customer continues along the status quo (with higher energy charges, and no FRD Charge), and on in which the customer pays an FRD Charge subject to the same structure available to Schedule TOU-EV-4 customers. This latter option would be attractive, for example, to customers with host accounts on TOU-GS-1 Option B, which has a (recently added)[42] FRD Charge.

With the exception of that modification, SCE does not propose changes to the design of Schedules TOU-EV-3 and TOU-EV-4. Both offer lower off-peak energy charges, subject to a floor price that is defined by D.07-11-052 as the sum of SCE's marginal generation and distribution costs plus non-bypassable charges. Both rates also provide an adequate amount of time for off-peak charging. Through load research ordered in D.11-07-029, SCE has tracked the adoption rate of these commercial EV rates, which have had a consistently small number of customers enrolled over the past several years.[43] Through interactions with customers as part of SCE's Business Customer plug-in EV engagement effort, SCE has found that many new commercial EV TOU rate customers are also charging golf carts and forklifts, not specifically EVs. Therefore, as SCE would like to continue to offer customer choice and options as the market continues to evolve, SCE plans to retain the current commercial EV rate options.

SCE anticipates that further research and discussion about commercial rates for electric transportation will take place in the recently opened rulemaking on alternative-fueled vehicles, R.13-11-007.

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42 SCE recently introduced FRD Charges to optional rates applicable to commercial/industrial customers with demands less than 20 kW.

43 Eighteen (18) customers were enrolled on Schedule TOU-EV-3, and 29 customers were enrolled on Schedule TOU-EV-4 as of November 2013.

IV.

RECONCILIATION WITH LATEST ADOPTED REVENUE REQUIREMENT AND REVENUE ALLOCATIONS

SCE's proposals will not increase or decrease overall revenue requirements, and rate group revenue allocations adopted in Phase 2 of SCE's 2012 GRC proceeding are maintained per the settlement approved in D.13-03-031.

V.

CONCLUSION

In summary, the Commission should adopt the proposed revisions to Option R, which result from a more expansive, current and representative data set; expanded studies into the cost drivers for the transmission and distribution components (separated by rate group); and methodologies that more closely align to the rate design of other SCE retail rates. However, the 150 MW cap on Option R should not be disturbed because Option R exacerbates the NEM cost-shift documented by the E3 Study and SCE's related study.

The Commission should also adopt SCE's EV rate design proposals, which (a) introduce a fixed monthly charge for the separately-metered domestic EV rate, consistent with Commission guidance; (b) eliminate the tiered domestic EV rate and replace it with an easy-to-understand, non-tiered rate that encourages optimal off-peak charging and provides a sensible adjustment for lower-usage customers; (c) offer all residential customers the opportunity to opt in to TOU rates, even though they were primarily designed for EV customers; and (d) revise commercial EV rates to make the demand charge structure consistent across both existing rate schedules.

Appendix A

Witness Qualifications

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY OF

ROBERT A. THOMAS

Q. Please state your name and business address for the record.

A. My name is Robert Thomas, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am Manager of the Rate Design Group in the Regulatory Operations Division of SCE's Regulatory Policy and Affairs Department. In this position, I am responsible for development of SCE's rate designs. I have held this position since November 20, 2006.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor's of Science and Engineering from the University of Arizona, a Masters in Business Administration from California State Polytechnic University, Pomona and a Professional Engineering License in Mechanical Engineering. Prior to my present position, my responsibilities have included Manager of the Analysis and Program Support Group, within SCE's Business Customer Division, where I was responsible for providing complex customer specific rate and financial analyses involving self-generation, load growth, contract rates, and hourly pricing options. Prior to this position, I was SCE's Program Manager for the Self Generation Incentive Program. In this position, I was responsible for all aspects of the program including dispute resolution, processing applications, program promotion and was SCE's lead representative on the Working Group.

Q. What is the purpose of your testimony in this proceeding?

A. I am sponsoring the testimony supporting SCE's "2013 Rate Design Window Application," as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

WITNESS QUALIFICATIONS AND PREPARED TESTIMONY OF

CYRUS SOROOSHIAN

Q. Please state your name and business address for the record.

A. My name is Cyrus Sorooshian, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A I am the Manager of Load Research in the Regulatory Policy and Affairs Department. My responsibilities include development, analysis, and reporting of load research studies in support of regulatory proceedings, pricing, forecasting, and load profiling for Direct Access.

Q. Briefly describe your educational and professional background.

A. I have a Master's degree in Economics from University of Southern California (USC) where I also completed all coursework required for a Ph.D. in Economics, with special emphasis in Econometrics. As a research assistant at USC, I was involved in energy research projects and specifically in load research studies. I joined SCE in 1984, as an Environmental Statistician in the Research and Development Department. I began working in SCE's Load Research group in 1985 as a Load Research Analyst. In that capacity, I was involved in all aspects of load research including sample design and selection, data management, estimation of load profiles for various rate groups and customer classes, market segmentation, statistical estimation, and econometrics modeling. I was promoted to my current position in 1994.

Q. What is the purpose of your testimony in this proceeding?

A. I am sponsoring the testimony supporting SCE's "2013 Rate Design Window Application," as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A. Yes it does.
Q. Does this conclude your qualifications and prepared testimony?
A. Yes, it does.

Appendix B

Option R Rate Design Structure

	Current Rates Effective (11-18-13)			Proposed Rates RDW			
	Delivery	Generation	Total	Delivery	Generation	Total	Total Rate Change
TOU-GS-2							
Time-of-use energy charge - $/kWh							
Summer On Peak	0.03797	0.31197	0.34994	0.03113	0.31197	0.34310	(1.95%)
Summer Mid Peak	0.03797	0.10957	0.14754	0.03113	0.10957	0.14070	(4.64%)
Summer Off Peak	0.03797	0.03507	0.07304	0.03113	0.03507	0.06620	(9.36%)
Winter On Peak	0.03797	0.06140	0.09937	0.03113	0.06140	0.09253	(6.88%)
Winter Mid Peak	0.03797	0.04001	0.07798	0.03113	0.04001	0.07114	(8.77%)
Customer charge - $/month	195.87		195.87	195.87		195.87	0.00%
Facility-related demand charge - $/kW	8.83		8.83	10.84		10.84	22.76%
Applicable kVar adjustment - $/kVar							
Time-related demand charge - $/kW							
Summer On Peak							
Summer Mid Peak							
TOU-GS-3							
Time-of-use energy charge - $/kWh							
Summer On Peak	0.03677	0.31139	0.34816	0.03929	0.31139	0.35068	0.72%
Summer Mid Peak	0.03677	0.10507	0.14184	0.03929	0.10507	0.14436	1.78%
Summer Off Peak	0.03677	0.03339	0.07016	0.03929	0.03339	0.07268	3.59%
Winter On Peak	0.03677	0.05775	0.09452	0.03929	0.05775	0.09704	2.67%
Winter Mid Peak	0.03677	0.03809	0.07486	0.03929	0.03809	0.07738	3.37%
Customer charge - $/month	435.46		435.46	435.46		435.46	0.00%
Facility-related demand charge - $/kW	10.90		10.90	10.02		10.02	(8.07%)
Applicable kVar adjustment - $/kVar							
Time-related demand charge - $/kW							
Summer On Peak							
Summer Mid Peak							

TOU-8-SEC							
Time-of-use energy charge - $/kWh							
Summer On Peak	0.03428	0.35525	0.38953	0.02641	0.35525	0.38166	(2.02%)
Summer Mid Peak	0.03428	0.11073	0.14501	0.02641	0.11073	0.13714	(5.43%)
Summer Off Peak	0.03428	0.03484	0.06912	0.02641	0.03484	0.06125	(11.39%)
Winter On Peak	0.03428	0.06007	0.09435	0.02641	0.06007	0.08648	(8.34%)
Winter Mid Peak	0.03428	0.03989	0.07417	0.02641	0.03989	0.06630	(10.61%)
Customer charge - $/month	600.86		600.86	600.86		600.86	0.00%
Facility-related demand charge - $/kW	10.38		10.38	13.49		13.49	29.96%
Applicable kVar adjustment - $/kVar							
Time-related demand charge - $/kW							
Summer On Peak							
Summer Mid Peak							
TOU-8-PRI							
Time-of-use energy charge - $/kWh							
Summer On Peak	0.03142	0.36493	0.39635	0.02936	0.36493	0.39429	(0.52%)
Summer Mid Peak	0.03142	0.10799	0.13941	0.02936	0.10799	0.13735	(1.48%)
Summer Off Peak	0.03142	0.03374	0.06516	0.02936	0.03374	0.06310	(3.16%)
Winter On Peak	0.03142	0.05846	0.08988	0.02936	0.05846	0.08782	(2.29%)
Winter Mid Peak	0.03142	0.03891	0.07033	0.02936	0.03891	0.06827	(2.93%)
Customer charge - $/month	314.86		314.86	314.86		314.86	0.00%
Facility-related demand charge - $/kW	9.85		9.85	10.73		10.73	8.93%
Applicable kVar adjustment - $/kVar							
Time-related demand charge - $/kW							
Summer On Peak							
Summer Mid Peak							
TOU-8-SUB							
Time-of-use energy charge - $/kWh							
Summer On Peak	0.02214	0.29349	0.31563	0.02144	0.29349	0.31493	(0.22%)
Summer Mid Peak	0.02214	0.09204	0.11418	0.02144	0.09204	0.11348	(0.61%)
Summer Off Peak	0.02214	0.03241	0.05455	0.02144	0.03241	0.05385	(1.28%)
Winter On Peak	0.02214	0.05537	0.07751	0.02144	0.05537	0.07681	(0.90%)
Winter Mid Peak	0.02214	0.03800	0.06014	0.02144	0.03800	0.05944	(1.16%)

Appendix C

Option R Study

Option R Study

Impact of Customers' Solar PV Installations on System Load

1. Introduction

Commercial and industrial customers with solar PV installations and annual demand between 20 kW and 4 MW are eligible to take service under the Option R rate option that was approved as part of a settlement agreement in Phase 2 of SCE's 2009 GRC. As a condition of settlement, SCE agreed to conduct a study to determine solar customers' impact on SCE system load and the effect of such impact on revenue allocation, and then propose a redesign of the distribution facilities-related demand charge to reflect the actual contribution to facilities-related peak demand drivers. In Phase 2 of SCE's 2012 GRC, the study was conducted using data available for TOU-GS-3 customers.

For this RDW Application, SCE expanded the study to include TOU-GS-2 and TOU-8 customers as well. SCE evaluated these customers' basic load statistics such as non-coincident demand, percent of usage in the on-peak period, demands at the time of system peak, and Effective Demand Factor (EDF).[44] Load statistics for solar customers were compared to those for the general population by rate group.

2. Methodology

Data from SCE's various databases were used to create the list of accounts that had PV systems installed before January 1, 2012. This list was then merged with the interval load data. Accounts that had both Delivered (by SCE to customers) and Received (by SCE from customers) energy measured in 2012 were used for this study. Interval load data for 2012 were used to calculate load statistics for solar accounts. The general population's load statistics by rate group were derived from the 2012 annual load studies.

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[44] EDF is the ratio of a customer's contribution to the peak load on a transmission or distribution circuit to the customer's annual non-coincident peak demand. It varies by type of customer and by the voltage level of the circuit. Unlike rate group coincident demand, which is measured for customers within a particular rate group, effective demand takes intergroup diversity into account. See A.11-06-007, Exh. SCE-2, Appendix B *Circuit Analysis for Determination of Effective Demand Factors*, for details on calculation of EDF for all the rate groups.

3. Results

Non-coincident demand and EDF for solar customers and for the population for each rate group are shown in Table 1 below. In each rate group, the percent of on-peak usage and EDF for solar customers are lower than those of the general population.

Table 1
2012 Option R Annual Load Study -- Delivered KWH

Rate Group		Number Of Accounts	Non-Coincident Demands (kW/Cust)	Percent Of On-Peak Usage	12 kV Effective Demand
GS-2	Solar	584	69.67	18.32%	0.35
	Overall	112,807	49.02	25.30%	0.61
TOU-GS-3	Solar	165	318.19	16.71%	0.42
	Overall	7,900	315.00	23.72%	0.69
TOU-8-PRI	Solar	52	1648.14	17.09%	0.62
	Overall	804	1954.91	19.55%	0.70
TOU-8-SEC	Solar	88	917.65	16.76%	0.62
	Overall	2,538	865.14	21.66%	0.74

Notes:
Solar: All accounts that have PV systems installed before January 1, 2012
and have both Delivered and Received energy measured.
December 2012 rate was used.
TOU-8-PRI and TOU-8-SEC were combined when calculating EDF for Solar.

Table 2 shows solar customers' monthly system coincident peak demands with the coincident peak demands for the population, for each rate group.

Table 2
2012 Option R Annual Load Study -- Delivered kWh
Monthly System Coincident Peak Demand

Rate Group	Date	Peak Time	Total # Of Accounts	# Of Solar Accounts	Population Avg. Demand (kW/Cust)	Solar Avg. Demand (kW/Cust)	Percent Of Change
GS-2	Tue, Jan 17, 2012	6:30P	111,988	579	17.23	24.99	45.003%
GS-2	Wed, Feb 15, 2012	7:00P	112,056	582	16.82	24.70	46.818%
GS-2	Mon, Mar 5, 2012	7:00P	112,451	582	17.58	23.41	33.128%
GS-2	Fri, Apr 20, 2012	3:00P	112,712	583	22.70	14.14	-37.692%
GS-2	Thu, May 31, 2012	3:30P	112,608	585	24.52	17.70	-27.810%
GS-2	Thu, Jun 28, 2012	3:30P	112,665	585	24.48	17.01	-30.516%
GS-2	Wed, Jul 11, 2012	3:00P	112,906	584	26.90	20.88	-22.380%
GS-2	Mon, Aug 13, 2012	2:00P	112,977	585	29.90	25.20	-15.718%
GS-2	Fri, Sep 14, 2012	3:30P	113,167	586	28.62	24.84	-13.216%
GS-2	Mon, Oct 1, 2012	3:30P	113,238	586	28.41	28.54	0.438%
GS-2	Mon, Nov 5, 2012	6:00P	113,406	585	20.39	28.46	39.586%
GS-2	Wed, Dec 19, 2012	7:00P	113,487	582	16.76	24.25	44.726%
							5.197%
TOU-GS-3	Tue, Jan 17, 2012	6:30P	7,862	165	131.14	131.49	0.266%
TOU-GS-3	Wed, Feb 15, 2012	7:00P	7,869	165	127.74	128.31	0.448%
TOU-GS-3	Mon, Mar 5, 2012	7:00P	7,865	165	134.88	134.24	-0.474%
TOU-GS-3	Fri, Apr 20, 2012	3:00P	7,883	165	173.12	70.68	-59.173%
TOU-GS-3	Thu, May 31, 2012	3:30P	7,899	165	177.35	86.15	-51.422%
TOU-GS-3	Thu, Jun 28, 2012	3:30P	7,903	165	171.48	76.51	-55.384%
TOU-GS-3	Wed, Jul 11, 2012	3:00P	7,911	165	184.78	97.76	-47.093%
TOU-GS-3	Mon, Aug 13, 2012	2:00P	7,925	165	213.38	131.25	-38.489%
TOU-GS-3	Fri, Sep 14, 2012	3:30P	7,926	165	197.89	124.59	-37.041%
TOU-GS-3	Mon, Oct 1, 2012	3:30P	7,927	165	202.72	141.71	-30.094%
TOU-GS-3	Mon, Nov 5, 2012	6:00P	7,919	165	156.97	163.45	4.131%
TOU-GS-3	Wed, Dec 19, 2012	7:00P	7,916	165	126.27	129.46	2.526%
							-25.983%
TOU-8-PRI	Tue, Jan 17, 2012	6:30P	799	52	950.91	862.17	-9.332%
TOU-8-PRI	Wed, Feb 15, 2012	7:00P	801	52	903.49	899.32	-0.461%
TOU-8-PRI	Mon, Mar 5, 2012	7:00P	798	52	957.83	924.02	-3.530%
TOU-8-PRI	Fri, Apr 20, 2012	3:00P	794	52	1040.57	684.62	-34.207%
TOU-8-PRI	Thu, May 31, 2012	3:30P	799	52	1091.81	758.65	-30.515%
TOU-8-PRI	Thu, Jun 28, 2012	3:30P	803	52	1064.35	713.70	-32.945%
TOU-8-PRI	Wed, Jul 11, 2012	3:00P	804	52	1127.51	808.48	-28.296%
TOU-8-PRI	Mon, Aug 13, 2012	2:00P	805	52	1178.69	899.15	-23.717%
TOU-8-PRI	Fri, Sep 14, 2012	3:30P	808	52	1161.19	875.45	-24.608%
TOU-8-PRI	Mon, Oct 1, 2012	3:30P	809	52	1150.78	915.41	-20.454%
TOU-8-PRI	Mon, Nov 5, 2012	6:00P	813	52	1072.14	985.39	-8.092%
TOU-8-PRI	Wed, Dec 19, 2012	7:00P	813	52	911.40	757.08	-16.933%
							-19.424%
TOU-8-SEC	Tue, Jan 17, 2012	6:30P	2,552	88	416.54	482.35	15.800%
TOU-8-SEC	Wed, Feb 15, 2012	7:00P	2,549	88	412.14	494.76	20.047%
TOU-8-SEC	Mon, Mar 5, 2012	7:00P	2,542	88	432.13	518.28	19.934%
TOU-8-SEC	Fri, Apr 20, 2012	3:00P	2,528	88	504.48	336.23	-33.351%
TOU-8-SEC	Thu, May 31, 2012	3:30P	2,529	88	523.17	376.56	-28.023%
TOU-8-SEC	Thu, Jun 28, 2012	3:30P	2,536	88	511.96	387.19	-24.371%
TOU-8-SEC	Wed, Jul 11, 2012	3:00P	2,537	88	538.90	424.20	-21.284%
TOU-8-SEC	Mon, Aug 13, 2012	2:00P	2,535	88	577.02	470.21	-18.511%
TOU-8-SEC	Fri, Sep 14, 2012	3:30P	2,545	88	550.70	514.67	-6.542%
TOU-8-SEC	Mon, Oct 1, 2012	3:30P	2,543	88	564.58	545.62	-3.358%
TOU-8-SEC	Mon, Nov 5, 2012	6:00P	2,539	88	484.23	600.20	23.950%
TOU-8-SEC	Wed, Dec 19, 2012	7:00P	2,537	88	408.75	481.03	17.683%
							-3.169%

Figures 1-4 below depict the average load profiles for solar customers compared to those of the general population, by rate group, on the 2012 system peak day. The first and third vertical reference lines, from left to right, indicate the boundaries of the on-peak period. The second reference line represents the system 30-minute peak time (2:00 PM PST).

Figure 1

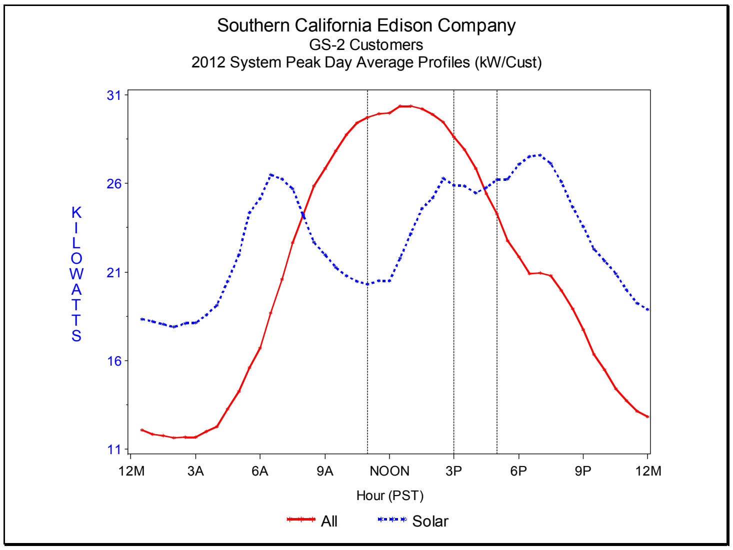


Figure 2

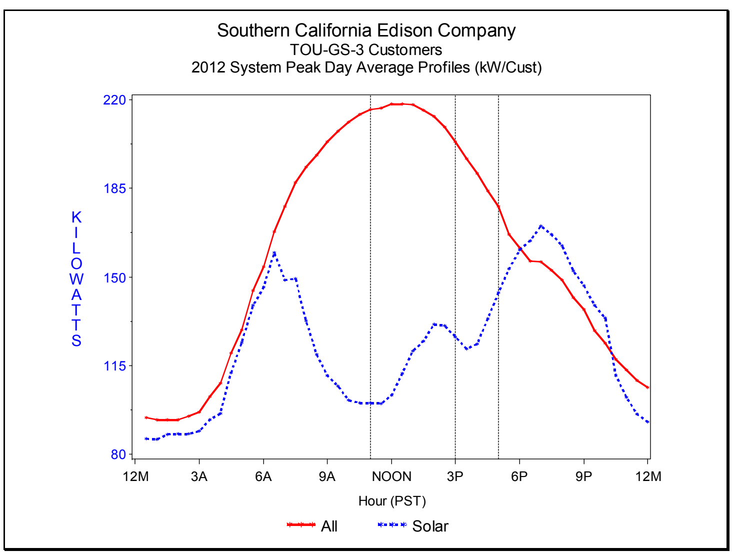


Figure 3

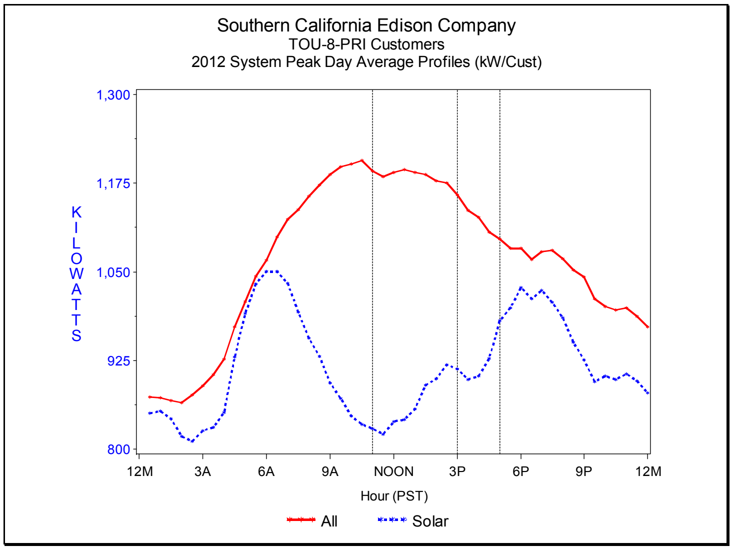
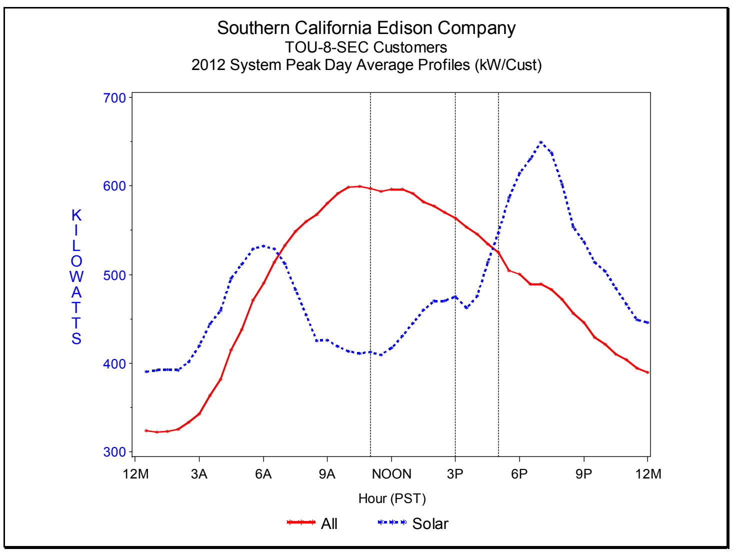
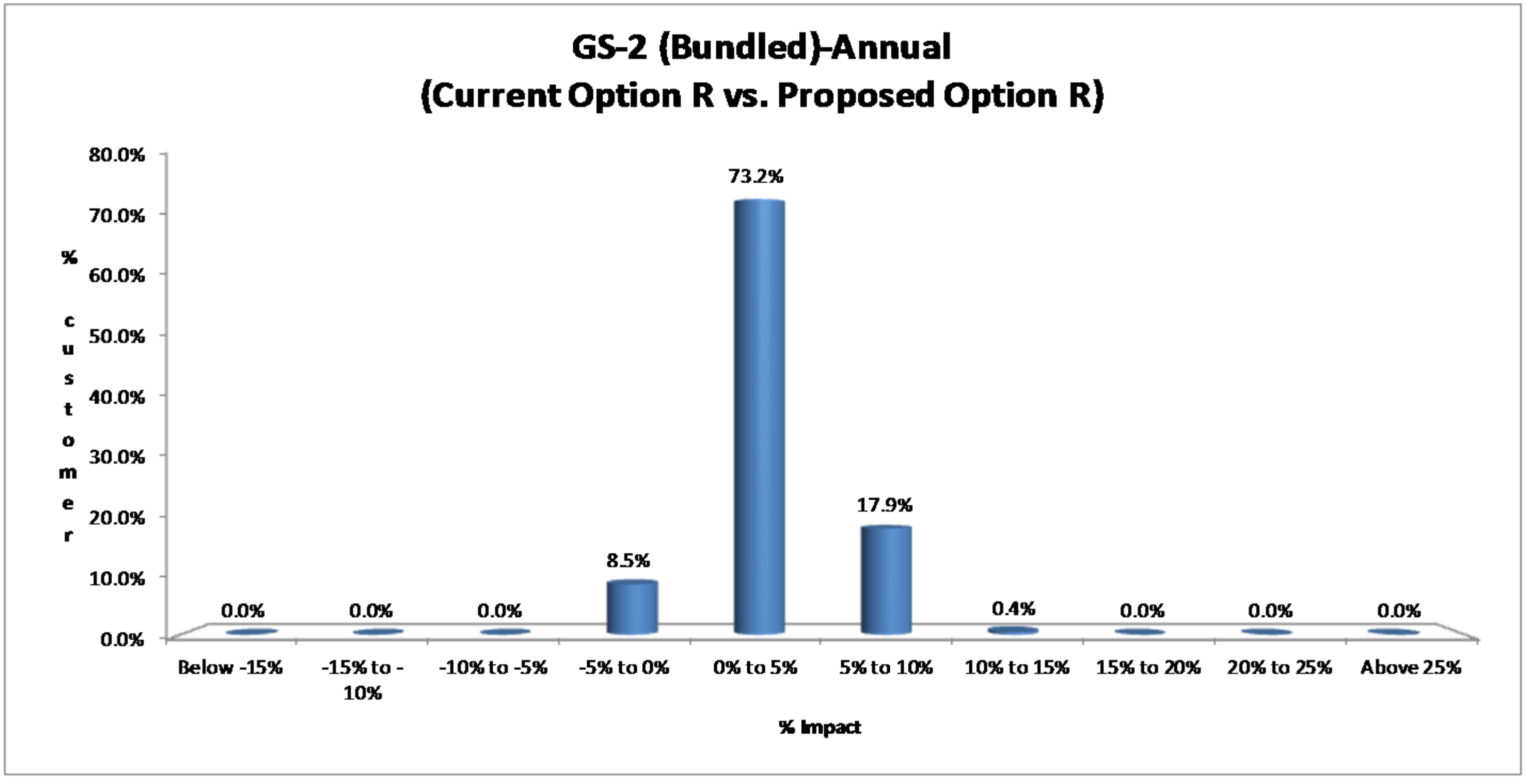


Figure 4

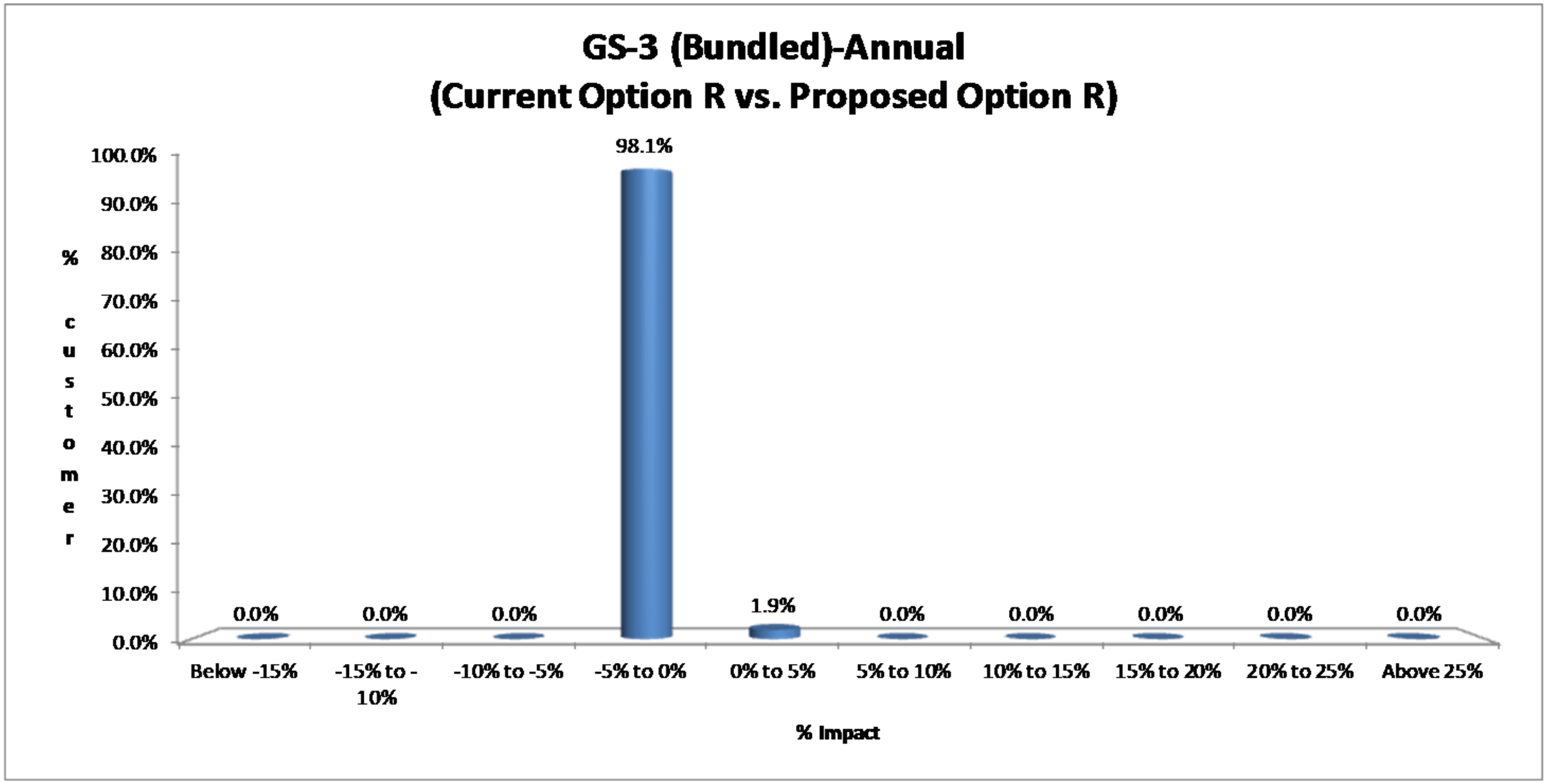


Appendix D

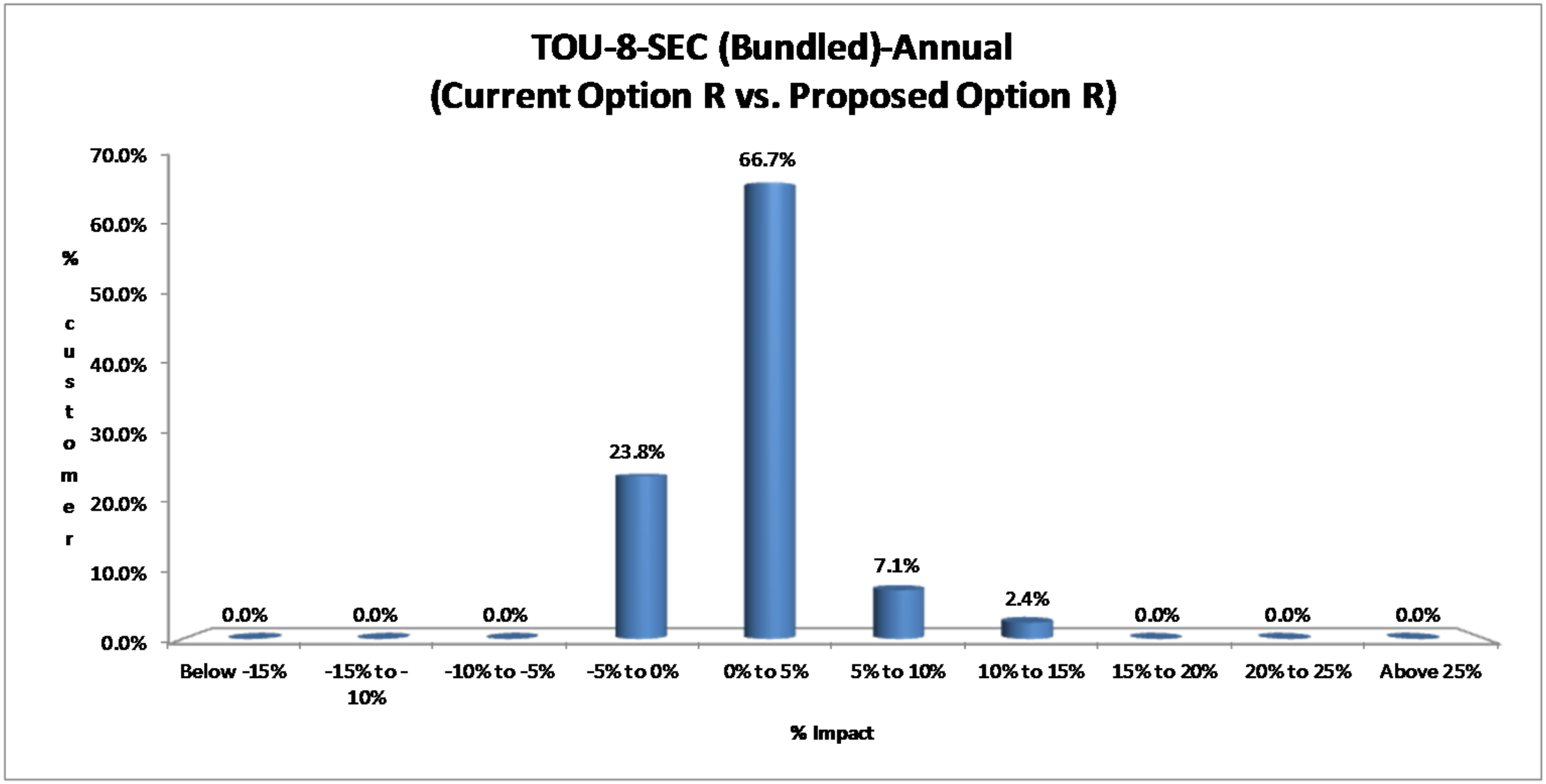
Option R Bill Impacts



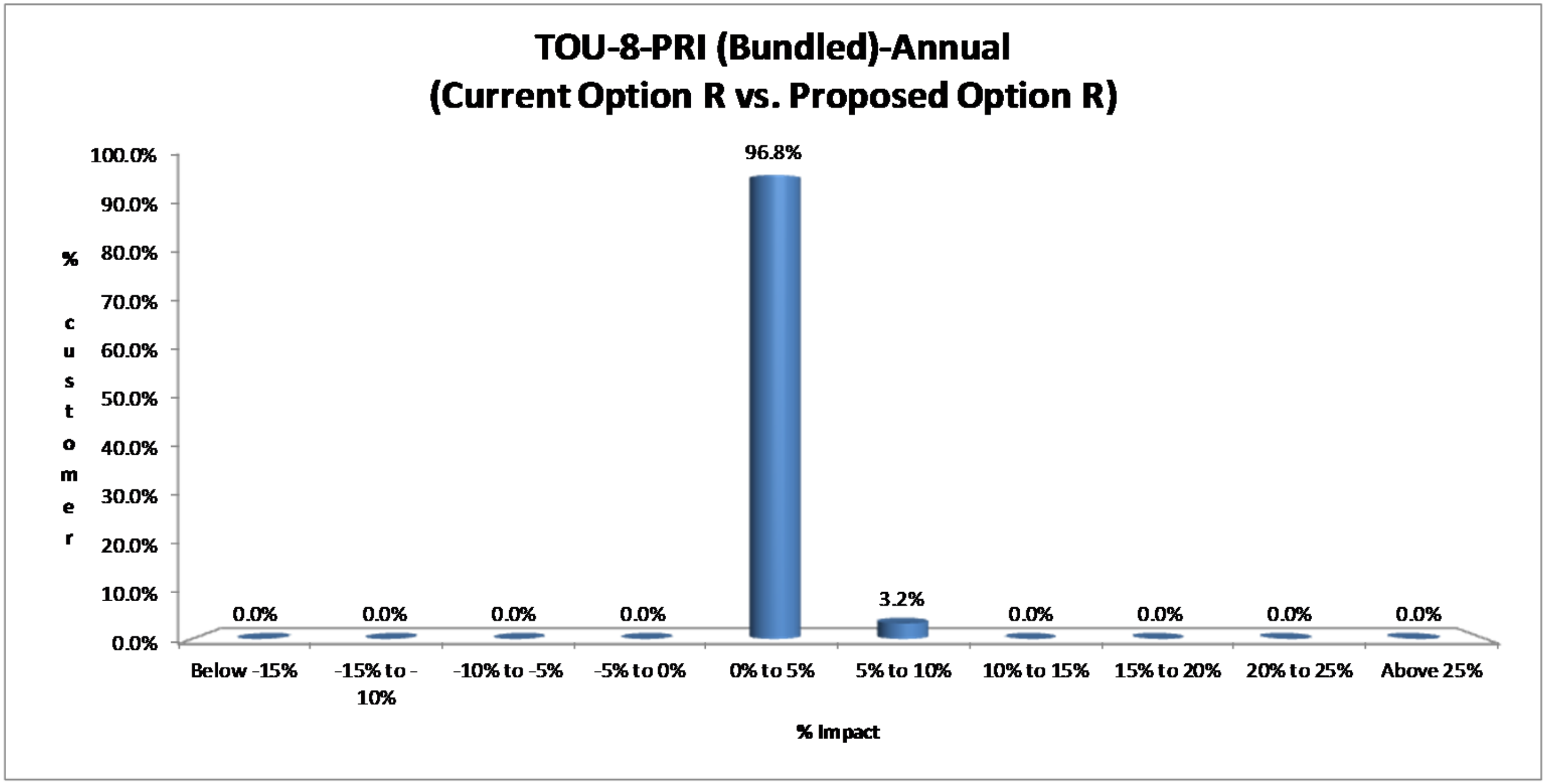
Impact	Customer		Average		Average Rates - ¢/kWh		Percent Impact - %			Average Monthly Bill - $		
%	Number	%	Bill days	Monthly kWh	Current Option R	Proposed Option R	Average	Minimum	Maximum	Current Option R	Proposed Option R	$ Bill Change
Below -15%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-15% to -10%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-10% to -5%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-5% to 0%	20	8.5%	366	20,899	14.0	13.9	-0.6%	-2.3%	0.0%	$2,886.4	$2,870.3	-$16.1
0% to 5%	172	73.2%	354	12,126	17.0	17.5	2.4%	0.0%	5.0%	$2,040.2	$2,089.3	$49.1
5% to 10%	42	17.9%	330	4,263	25.3	26.9	6.7%	5.0%	9.0%	$1,062.2	$1,133.4	$71.1
10% to 15%	1	0.4%	344	2,402	47.6	53.7	13.0%	13.0%	13.0%	$1,127.4	$1,273.4	$146.0
15% to 20%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
20% to 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Above 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Group Total	235	100.0%	351	11,541	17.1	17.5	2.4%	-2.3%	13.0%	$1,946.9	$1,994.3	$47.4



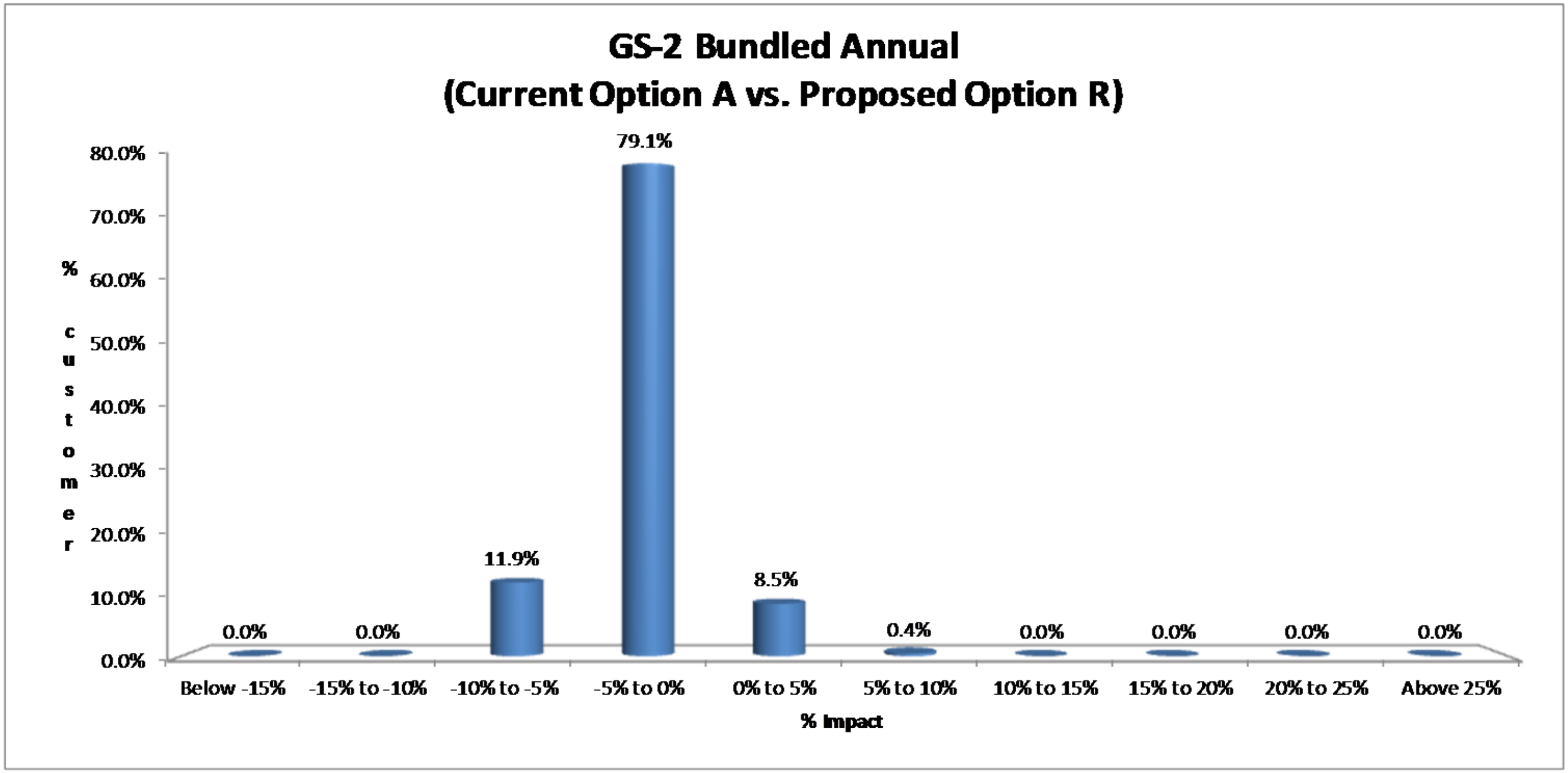
Impact	Customer		Average		Average Rates - ¢/kWh		Percent Impact - %			Average Monthly Bill - $		
%	Number	%	Bill days	Monthly kWh	Current Option R	Proposed Option R	Average	Minimum	Maximum	Current Option R	Proposed Option R	$ Bill Change
Below -15%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-15% to -10%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-10% to -5%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-5% to 0%	153	98.1%	365	47,410	16.8	16.6	-1.1%	-3.8%	0.0%	$7,844.3	$7,761.2	-$83.1
0% to 5%	3	1.9%	366	80,719	14.1	14.2	0.1%	0.1%	0.1%	$11,269.9	$11,277.6	$7.8
5% to 10%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
10% to 15%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
15% to 20%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
20% to 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Above 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Group Total	156	100.0%	365	48,052	16.7	16.5	-1.0%	-3.8%	0.1%	$7,910.3	$7,829.0	-$81.4



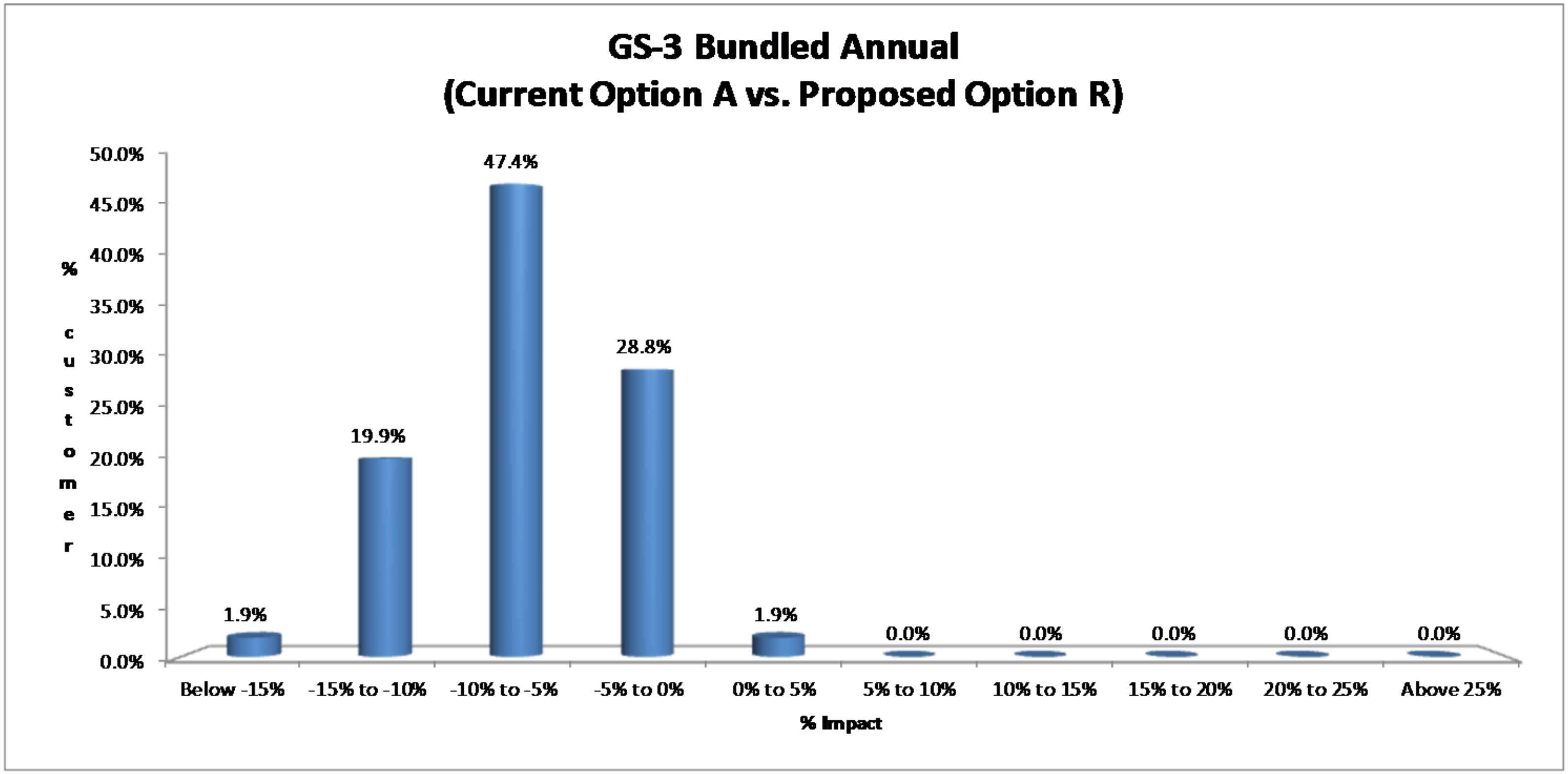
Impact	Customer		Average		Average Rates - ¢/kWh		Percent Impact - %			Average Monthly Bill - $		
%	Number	%	Bill days	Monthly kWh	Current Option R	Proposed Option R	Average	Minimum	Maximum	Current Option R	Proposed Option R	$ Bill Change
Below -15%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-15% to -10%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-10% to -5%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-5% to 0%	10	23.8%	366	282,722	13.0	12.9	-1.1%	-2.0%	-0.2%	$36,380.9	$35,998.2	-$382.6
0% to 5%	28	66.7%	366	143,897	15.5	15.8	2.0%	0.1%	4.2%	$21,984.5	$22,414.1	$429.6
5% to 10%	3	7.1%	366	54,082	21.3	22.9	7.5%	6.9%	8.1%	$11,357.5	$12,204.0	$846.6
10% to 15%	1	2.4%	366	38,602	23.4	25.8	10.2%	10.2%	10.2%	$8,910.4	$9,814.9	$904.6
15% to 20%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
20% to 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Above 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Group Total	42	100.0%	366	168,028	14.7	14.8	1.1%	-2.0%	10.2%	$24,341.9	$24,619.2	$277.3



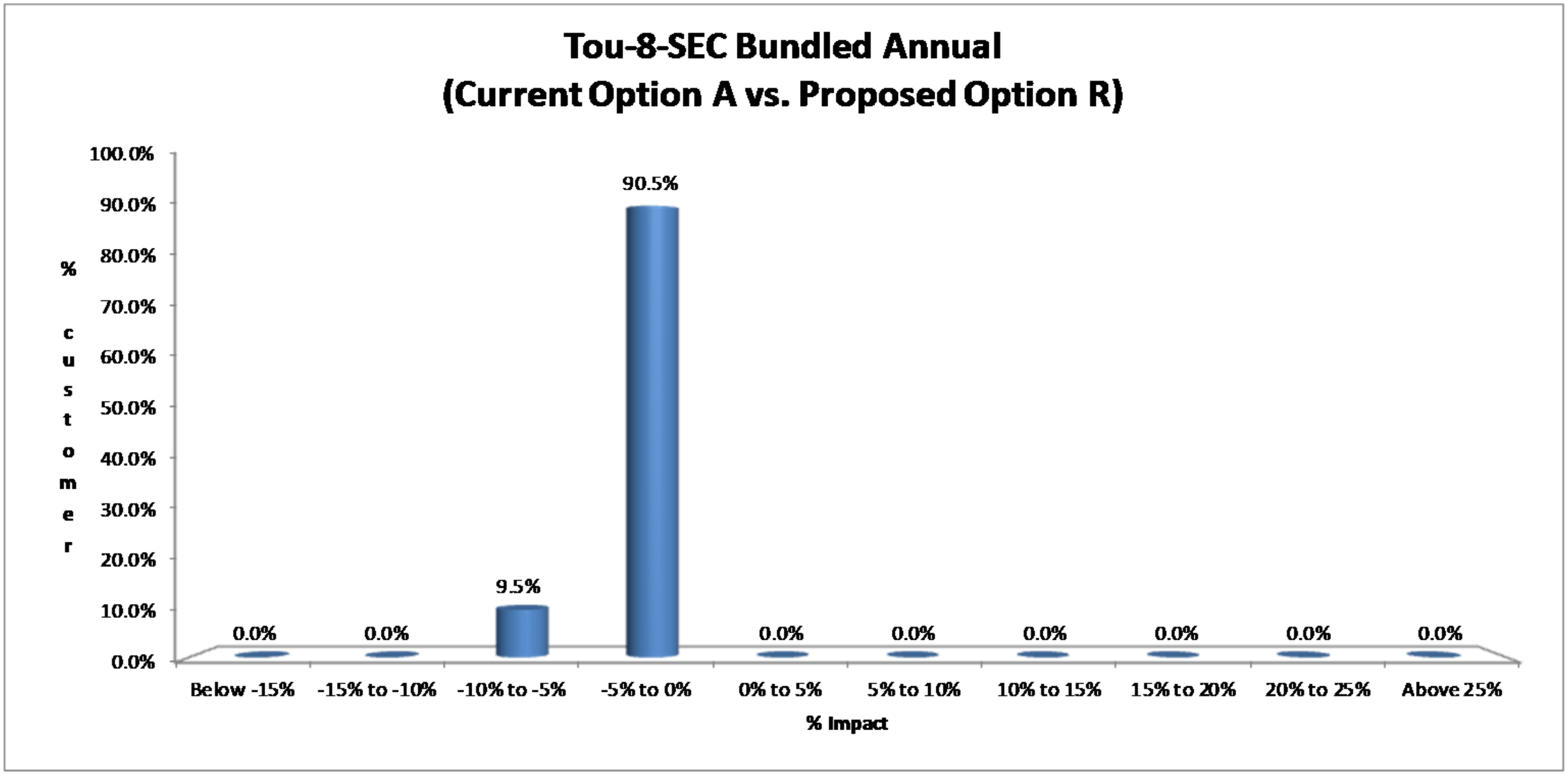
Impact	Customer		Average		Average Rates - ¢/kWh		Percent Impact - %			Average Monthly Bill - $		
%	Number	%	Bill days	Monthly kWh	Current Option R	Proposed Option R	Average	Minimum	Maximum	Current Option R	Proposed Option R	$ Bill Change
Below -15%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-15% to -10%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-10% to -5%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-5% to 0%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
0% to 5%	30	96.8%	366	295,400	12.7	12.9	1.8%	0.7%	4.1%	$36,881.3	$37,536.2	$654.9
5% to 10%	1	3.2%	308	70,192	16.2	17.2	5.7%	5.7%	5.7%	$11,246.8	$11,884.5	$637.7
10% to 15%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
15% to 20%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
20% to 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Above 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Group Total	31	100.0%	364	289,255	12.7	12.9	1.8%	0.0%	5.7%	$36,181.9	$36,836.3	$654.4



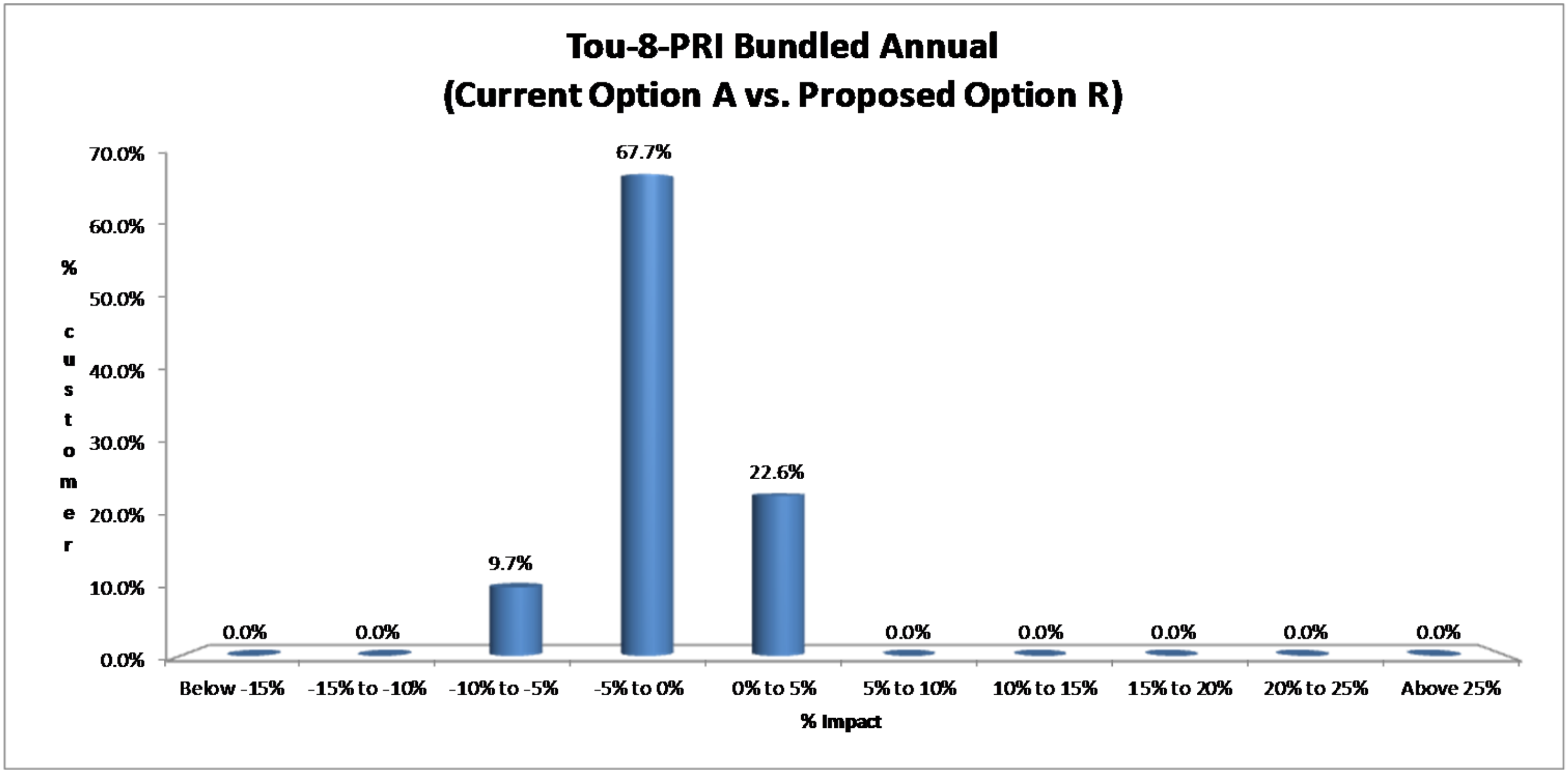
Impact	Customer		Average		Average Rates - ¢/kWh		Percent Impact - %			Average Monthly Bill - $		
%	Number	%	Bill days	Monthly kWh	Current Option A	Proposed Option R	Average	Minimum	Maximum	Current Option A	Proposed Option R	$ Bill Change
Below -15%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-15% to -10%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-10% to -5%	28	11.9%	335	4,228	29.8	28.1	-5.9%	-9.4%	-5.0%	$1,245.3	$1,172.3	-$73.0
-5% to 0%	186	79.1%	352	11,565	18.0	17.7	-2.2%	-5.0%	0.0%	$2,059.0	$2,014.6	-$44.4
0% to 5%	20	8.5%	366	20,899	13.8	13.9	0.5%	0.0%	2.2%	$2,855.6	$2,870.3	$14.7
5% to 10%	1	0.4%	366	7,367	24.1	25.9	7.5%	7.5%	7.5%	$1,753.9	$1,885.5	$131.6
10% to 15%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
15% to 20%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
20% to 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Above 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Group Total	235	100.0%	351	11,541	17.9	17.5	-2.0%	-9.4%	7.5%	$2,035.9	$1,994.3	-$41.6



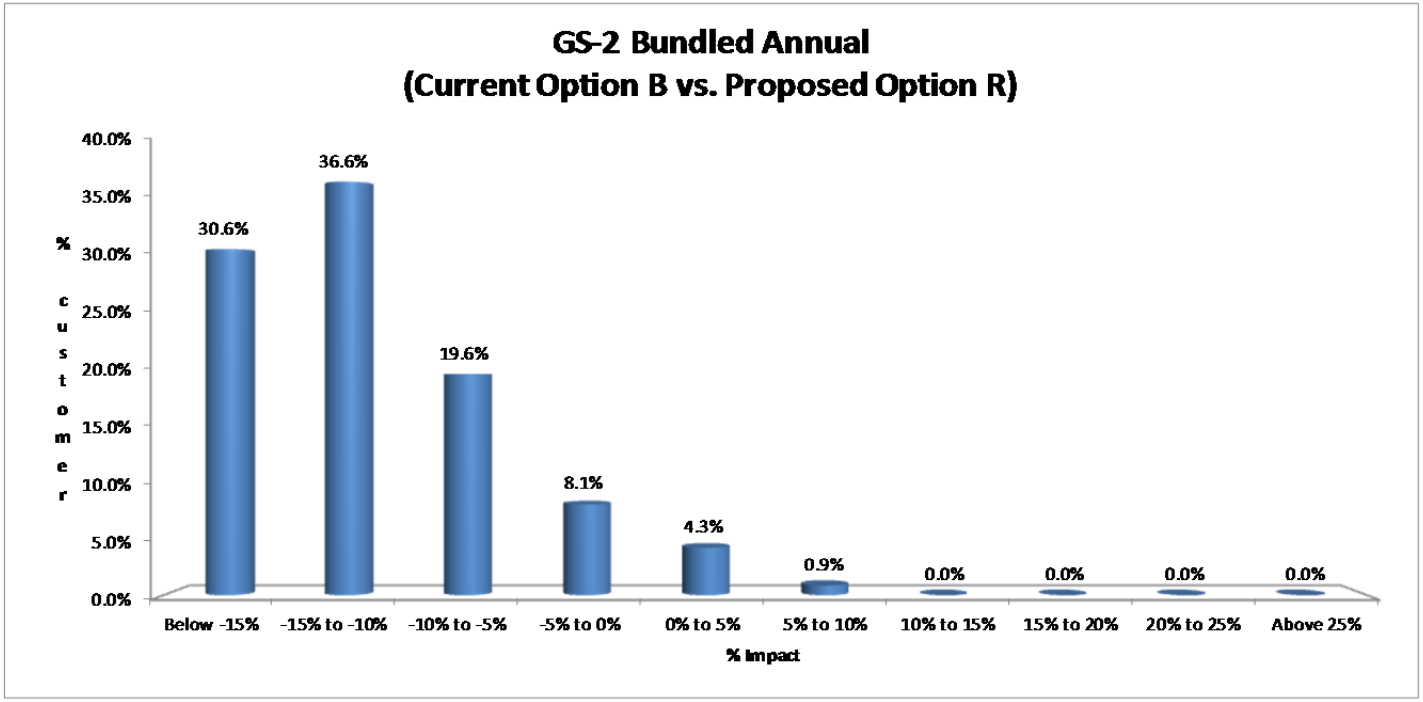
Impact	Customer		Average		Average Rates - ¢/kWh		Percent Impact - %			Average Monthly Bill - $		
%	Number	%	Bill days	Monthly kWh	Current Option A	Proposed Option R	Average	Minimum	Maximum	Current Option A	Proposed Option R	$ Bill Change
Below -15%	3	1.9%	362	17,200	33.9	27.4	-19.2%	-20.3%	-17.5%	$5,755.7	$4,649.6	-$1,106.1
-15% to -10%	31	19.9%	366	25,249	22.3	19.6	-12.3%	-14.5%	-10.1%	$5,563.5	$4,881.6	-$681.8
-10% to -5%	74	47.4%	364	44,191	18.4	17.0	-7.3%	-9.9%	-5.0%	$8,009.3	$7,428.1	-$581.2
-5% to 0%	45	28.8%	366	69,937	15.6	15.2	-2.8%	-5.0%	-0.3%	$10,795.6	$10,495.2	-$300.4
0% to 5%	3	1.9%	366	80,719	14.1	14.2	0.4%	0.4%	0.6%	$11,228.1	$11,277.6	$49.6
5% to 10%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
10% to 15%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
15% to 20%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
20% to 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Above 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Group Total	156	100.0%	365	48,052	17.6	16.5	-6.2%	-20.3%	0.6%	$8,346.9	$7,829.0	-$517.9



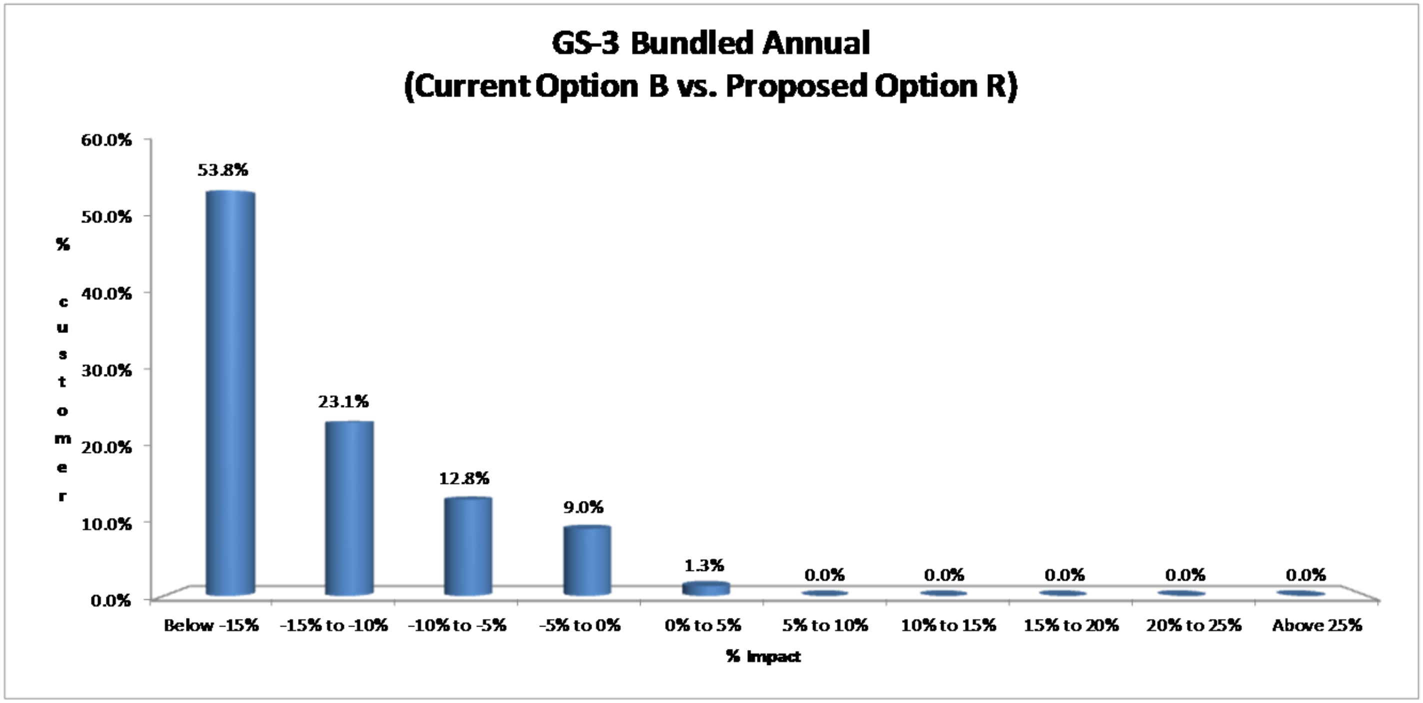
Impact	Customer		Average		Average Rates - ¢/kWh		Percent Impact - %			Average Monthly Bill - $		
%	Number	%	Bill days	Monthly kWh	Current Option A	Proposed Option R	Average	Minimum	Maximum	Current Option A	Proposed Option R	$ Bill Change
Below -15%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-15% to -10%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-10% to -5%	4	9.5%	366	50,212	25.0	23.4	-6.2%	-7.3%	-5.5%	$12,370.4	$11,606.8	-$763.6
-5% to 0%	38	90.5%	366	180,430	14.9	14.6	-2.2%	-4.3%	-0.4%	$26,572.4	$25,988.9	-$583.5
0% to 5%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
5% to 10%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
10% to 15%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
15% to 20%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
20% to 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Above 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Group Total	42	100.0%	366	168,028	15.2	14.8	-2.4%	-7.3%	0.0%	$25,219.9	$24,619.2	-$600.7



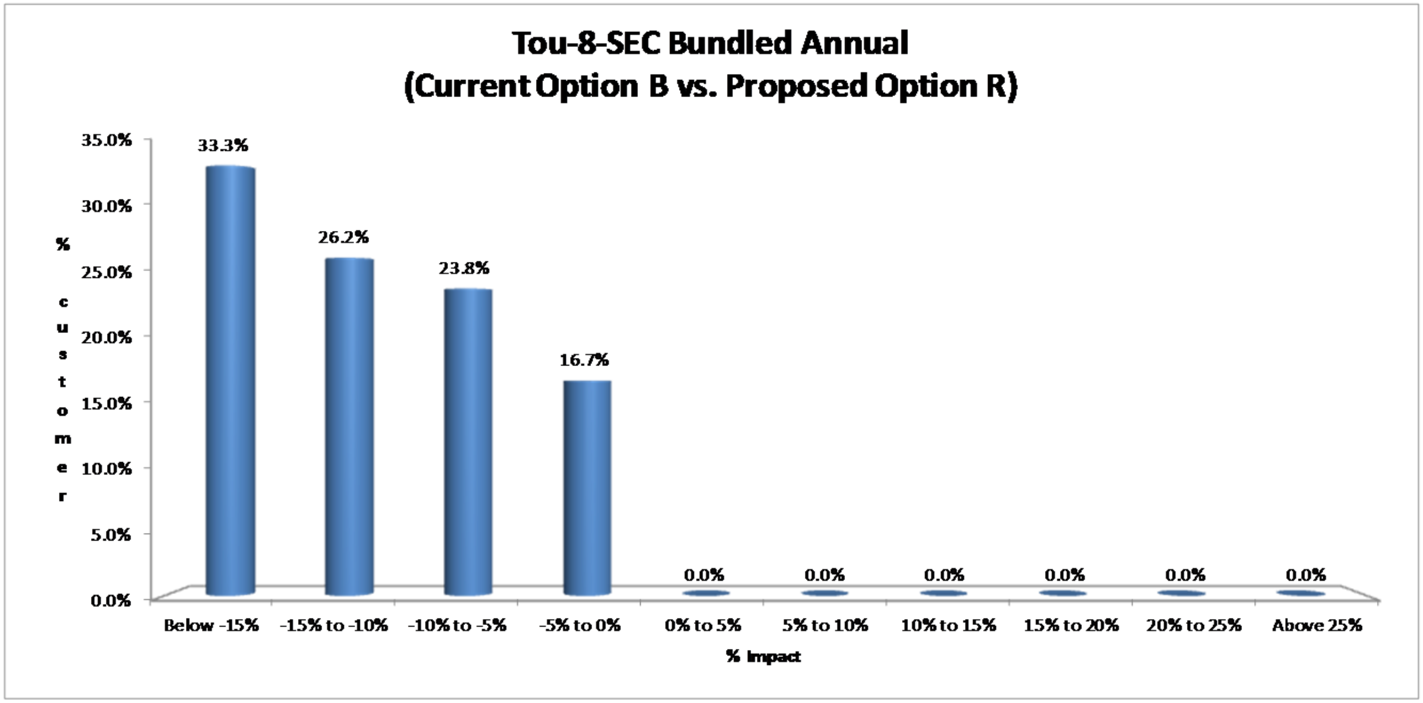
Impact	Customer		Average		Average Rates - ¢/kWh		Percent Impact - %			Average Monthly Bill - $		
%	Number	%	Bill days	Monthly kWh	Current Option A	Proposed Option R	Average	Minimum	Maximum	Current Option A	Proposed Option R	$ Bill Change
Below -15%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-15% to -10%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
-10% to -5%	3	9.7%	347	138,562	16.3	15.3	-5.7%	-8.2%	-5.0%	$22,223.2	$20,960.6	-$1,262.6
-5% to 0%	21	67.7%	366	190,960	14.4	14.1	-1.9%	-4.8%	-0.1%	$27,170.1	$26,650.9	-$519.2
0% to 5%	7	22.6%	366	645,309	11.5	11.6	1.0%	0.2%	2.0%	$73,122.3	$73,837.0	$714.6
5% to 10%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
10% to 15%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
15% to 20%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
20% to 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Above 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Group Total	31	100.0%	364	289,255	13.0	12.9	-0.8%	-8.2%	2.0%	$37,143.9	$36,836.3	-$307.6



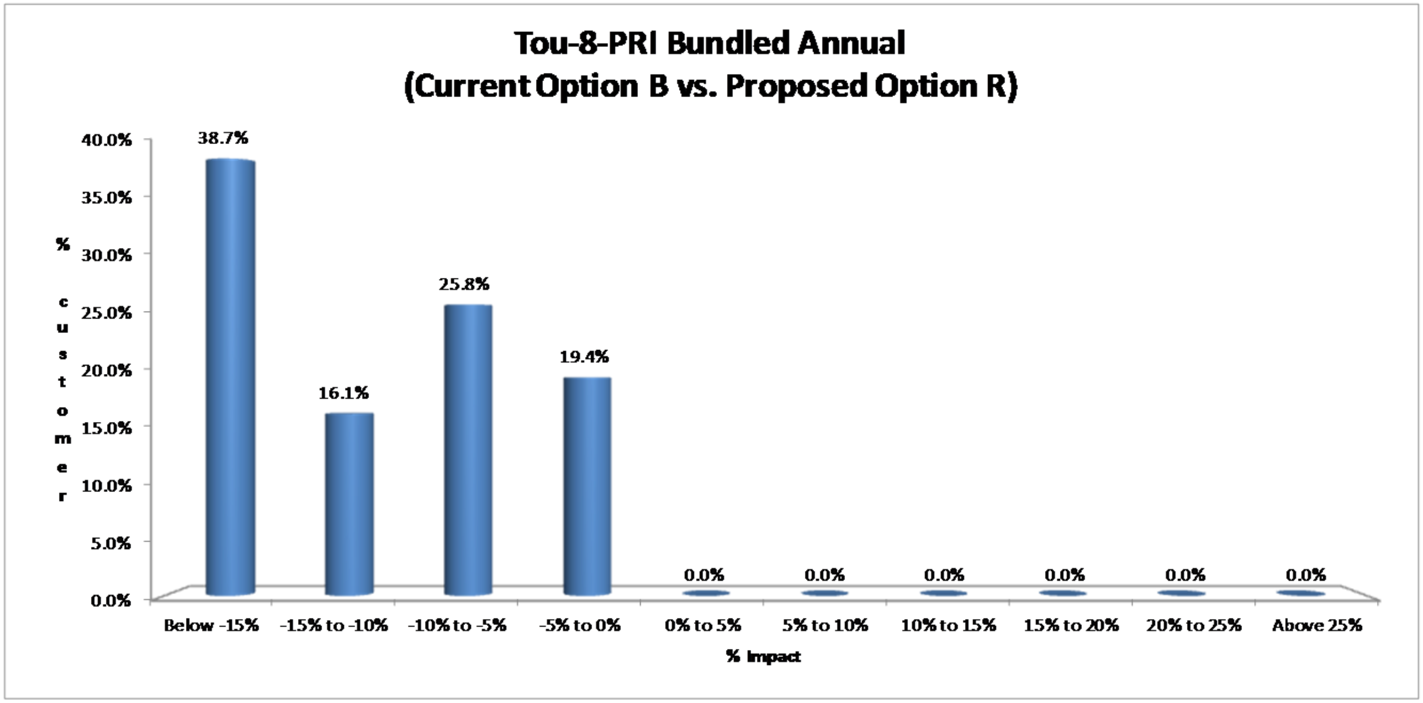
Impact	Customer		Average		Average Rates - ¢/kWh		Percent Impact - %			Average Monthly Bill - $		
%	Number	%	Bill days	Monthly kWh	Current Option B	Proposed Option R	Average	Minimum	Maximum	Current Option B	Proposed Option R	$ Bill Change
Below -15%	72	30.6%	339	7,793	24.8	20.2	-18.7%	-29.7%	-15.1%	$1,909.2	$1,553.1	-$356.1
-15% to -10%	86	36.6%	356	10,911	20.4	17.8	-12.7%	-15.0%	-10.0%	$2,198.1	$1,919.8	-$278.2
-10% to -5%	46	19.6%	359	14,185	17.3	16.0	-7.4%	-10.0%	-5.1%	$2,419.2	$2,240.7	-$178.5
-5% to 0%	19	8.1%	342	11,775	17.5	16.9	-3.5%	-5.0%	0.0%	$2,028.3	$1,958.2	-$70.0
0% to 5%	10	4.3%	366	27,451	15.5	15.8	1.7%	0.3%	2.6%	$4,209.5	$4,281.0	$71.5
5% to 10%	2	0.9%	366	21,539	13.9	14.8	6.4%	5.9%	7.5%	$2,955.3	$3,143.5	$188.2
10% to 15%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
15% to 20%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
20% to 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Above 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Group Total	235	100.0%	351	11,541	19.7	17.5	-10.9%	-29.7%	7.5%	$2,239.5	$1,994.3	-$245.2



Impact	Customer		Average		Average Rates - ¢/kWh		Percent Impact - %			Average Monthly Bill - $		
%	Number	%	Bill days	Monthly kWh	Current Option B	Proposed Option R	Average	Minimum	Maximum	Current Option B	Proposed Option R	$ Bill Change
Below -15%	84	53.8%	364	34,238	22.4	17.9	-20.0%	-34.7%	-15.1%	$7,566.1	$6,049.4	-$1,516.6
-15% to -10%	36	23.1%	366	51,501	18.3	15.9	-12.8%	-14.8%	-10.1%	$9,279.9	$8,093.4	-$1,186.5
-10% to -5%	20	12.8%	366	67,563	17.0	15.8	-7.1%	-10.0%	-5.1%	$11,338.2	$10,532.9	-$805.2
-5% to 0%	14	9.0%	366	87,426	15.5	15.1	-2.8%	-4.9%	-0.1%	$13,390.8	$13,020.8	-$370.0
0% to 5%	2	1.3%	366	92,924	15.3	15.4	0.7%	0.5%	0.9%	$14,012.8	$14,106.2	$93.4
5% to 10%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
10% to 15%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
15% to 20%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
20% to 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Above 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Group Total	156	100.0%	365	48,052	19.1	16.5	-13.5%	-34.7%	0.9%	$9,054.0	$7,829.0	-$1,225.0



Impact	Customer		Average		Average Rates - ¢/kWh		Percent Impact - %			Average Monthly Bill - $		
%	Number	%	Bill days	Monthly kWh	Current Option B	Proposed Option R	Average	Minimum	Maximum	Current Option B	Proposed Option R	$ Bill Change
Below -15%	14	33.3%	366	89,320	21.4	17.4	-18.9%	-22.5%	-17.0%	$18,903.7	$15,328.7	-$3,574.9
-15% to -10%	11	26.2%	366	162,651	17.0	15.0	-12.1%	-14.9%	-10.2%	$27,293.8	$24,004.3	-$3,289.5
-10% to -5%	10	23.8%	366	191,252	16.2	15.0	-7.4%	-9.9%	-5.2%	$30,598.3	$28,346.3	-$2,252.0
-5% to 0%	7	16.7%	366	300,717	13.4	13.1	-2.2%	-4.8%	-0.4%	$39,698.5	$38,841.8	-$856.7
0% to 5%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
5% to 10%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
10% to 15%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
15% to 20%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
20% to 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Above 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Group Total	42	100.0%	366	168,028	16.5	14.8	-10.0%	-22.5%	0.0%	$27,351.3	$24,619.2	-$2,732.1



Impact	Customer		Average		Average Rates - ¢/kWh		Percent Impact - %			Average Monthly Bill - $		
%	Number	%	Bill days	Monthly kWh	Current Option B	Proposed Option R	Average	Minimum	Maximum	Current Option B	Proposed Option R	$ Bill Change
Below -15%	12	38.7%	361	133,430	17.6	14.4	-18.2%	-23.1%	-15.4%	$23,203.6	$18,982.7	-$4,220.9
-15% to -10%	5	16.1%	366	152,348	15.9	13.7	-13.5%	-14.0%	-11.7%	$23,881.1	$20,668.3	-$3,212.8
-10% to -5%	8	25.8%	366	299,856	14.7	13.6	-7.2%	-9.3%	-5.4%	$43,404.8	$40,271.2	-$3,133.6
-5% to 0%	6	19.4%	366	696,741	12.1	11.8	-2.4%	-3.8%	-0.6%	$82,964.0	$80,965.4	-$1,998.6
0% to 5%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
5% to 10%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
10% to 15%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
15% to 20%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
20% to 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Above 25%	0	0.0%	0	0	0.0	0.0	0.0%	0.0%	0.0%	$0.0	$0.0	$0.0
Group Total	31	100.0%	364	289,255	14.1	12.9	-8.3%	-23.1%	0.0%	$40,179.4	$36,836.3	-$3,343.1

Appendix E

Proposed EV Rate Design Structure

	October 2013 Rates			Proposed Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-EV-1							
Energy Charge - $/kWh							
Summer Season - On-Peak	0.14790	0.18252	0.33042	0.13873	0.19908	0.33781	2.2%
Off-Peak	0.06978	0.03608	0.10586	0.06978	0.04664	0.11642	10.0%
Winter Season - On-Peak	0.14790	0.07852	0.22642	0.13873	0.07057	0.20930	-7.6%
Off-Peak	0.06978	0.03950	0.10928	0.06978	0.04157	0.11135	1.9%
Basic Charge - $/month				2.64		2.64	
TOU-D-TEV							
Energy Charge - $/kWh							
Summer Season							
Level I (up to 130% of Baseline) - On-Peak	0.04729	0.23357	0.28086				
Level II (More than 130% of Baseline) - On-Peak	0.23274	0.23357	0.46631				
Level I (up to 130% of Baseline) - Off-Peak	0.04729	0.07639	0.12368				
Level II (More than 130% of Baseline) - Off-Peak	0.23274	0.07639	0.30913				
Level I (up to 130% of Baseline) - Super-Off-Peak	0.06978	0.02290	0.09268				
Level II (More than 130% of Baseline) - Super-Off-Peak	0.06978	0.02290	0.09268				
Winter Season							
Level I (up to 130% of Baseline) - On-Peak	0.04729	0.11357	0.16086				
Level II (More than 130% of Baseline) - On-Peak	0.23274	0.11357	0.34631				
Level I (up to 130% of Baseline) - Off-Peak	0.04729	0.05996	0.10725				
Level II (More than 130% of Baseline) - Off-Peak	0.23274	0.05996	0.29270				
Level I (up to 130% of Baseline) - Super-Off-Peak	0.06978	0.03090	0.10068				
Level II (More than 130% of Baseline) - Super-Off-Peak	0.06978	0.03090	0.10068				
Basic Charge - $/day							
Single-Family Residence	0.030	0.000	0.030				
Multi-Family Residence	0.023	0.000	0.023				
Minimum Charge - $/day							
Single Family Residence	0.059	0.000	0.059				
Multi-Family Residence	0.044	0.000	0.044				
Peak Time Rebate - $kWh							
Peak Time Rebate		(0.75)	(0.75)				
w/enabling technology - $/kWh		(1.25)	(1.25)				
TOU-D (Option A)							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.12963	0.27272	0.40235	
Off-Peak				0.12963	0.11646	0.24609	
Super-Off-Peak				0.06978	0.03911	0.10889	
Summer Season							
On-Peak				0.12963	0.15067	0.28030	
Off-Peak				0.12963	0.08288	0.21251	
Super-Off-Peak				0.06978	0.03930	0.10908	
Baseline Credit - $/kWh					(0.03848)	(0.03848)	
Basic Charge - $/day				0.030	0.000	0.030	
Minimum Charge - $/day				0.059	0.000	0.059	
Peak Time Rebate - $kWh							
Peak Time Rebate					(0.75)	(0.75)	
w/enabling technology - $/kWh					(1.25)	(1.25)	

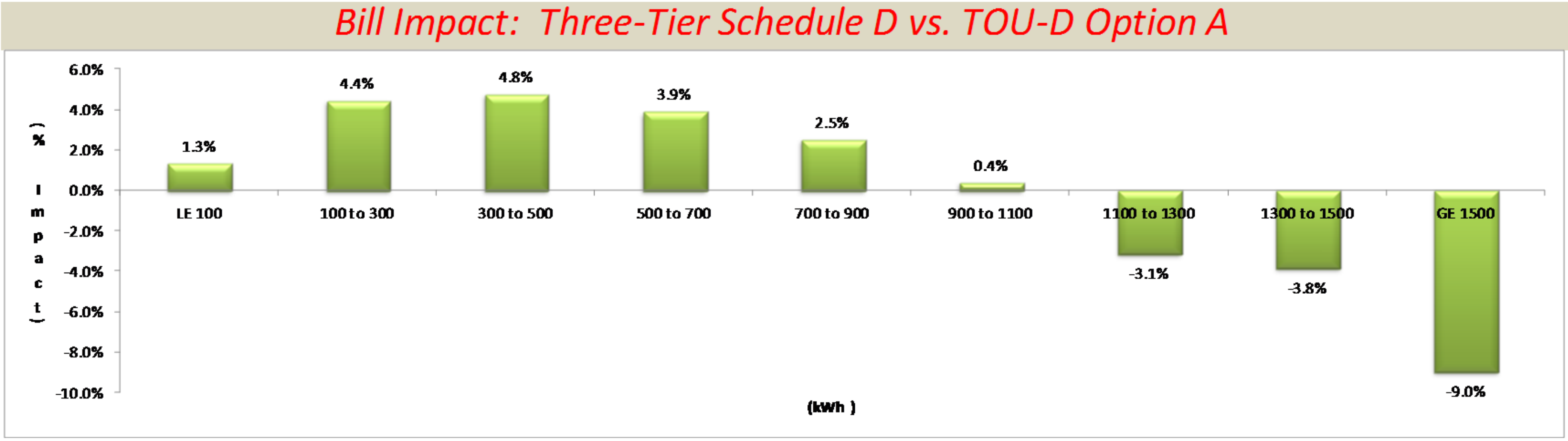
	October 2013 Rates			Proposed Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-D (Option B)							
Energy Charge - $/kWh							
Summer Season							
On-Peak				0.09421	0.24437	0.33858	
Off-Peak				0.09421	0.08812	0.18232	
Super-Off-Peak				0.06978	0.03911	0.10889	
Summer Season							
On-Peak				0.09421	0.12233	0.21653	
Off-Peak				0.09421	0.05453	0.14874	
Super-Off-Peak				0.06978	0.03930	0.10908	
Basic Charge - $/day				0.538	0.000	0.538	
Minimum Charge - $/day				0.059	0.000	0.059	
Peak Time Rebate - $kWh							
Peak Time Rebate					(0.75)	(0.75)	
w/enabling technology - $/kWh					(1.25)	(1.25)	
TOU-EV-3 (Option A)							
Energy Charge - $/kWh							
Summer Season On-Peak	0.06032	0.25206	0.31238	0.06032	0.25206	0.31238	0.0%
Mid-Peak	0.06032	0.09067	0.15099	0.06032	0.09067	0.15099	0.0%
Off-Peak	0.06032	0.02483	0.08515	0.06032	0.02483	0.08515	0.0%
Winter Season On-Peak	0.06032	0.07565	0.13597	0.06032	0.07565	0.13597	0.0%
Mid-Peak	0.06032	0.06314	0.12346	0.06032	0.06314	0.12346	0.0%
Off-Peak	0.06032	0.03372	0.09404	0.06032	0.03372	0.09404	0.0%
Customer Charge - $/day	0.836		0.836	0.836		0.836	0.0%
TOU-EV-3 (Option B)							
Energy Charge - $/kWh							
Summer Season On-Peak				0.02390	0.25206	0.27596	
Mid-Peak				0.02390	0.09067	0.11457	
Off-Peak				0.02390	0.02483	0.04873	
Winter Season On-Peak				0.02390	0.07565	0.09955	
Mid-Peak				0.02390	0.06314	0.08704	
Off-Peak				0.02390	0.03372	0.05762	
Customer Charge - $/day				0.836		0.836	
Facilities Related							
Demand Charge - $/kW				6.71		6.71	
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV				(0.10)		(0.10)	
Above 50 kV but below 220 kV				(3.28)		(3.28)	
At 220 kV				(4.74)		(4.74)	

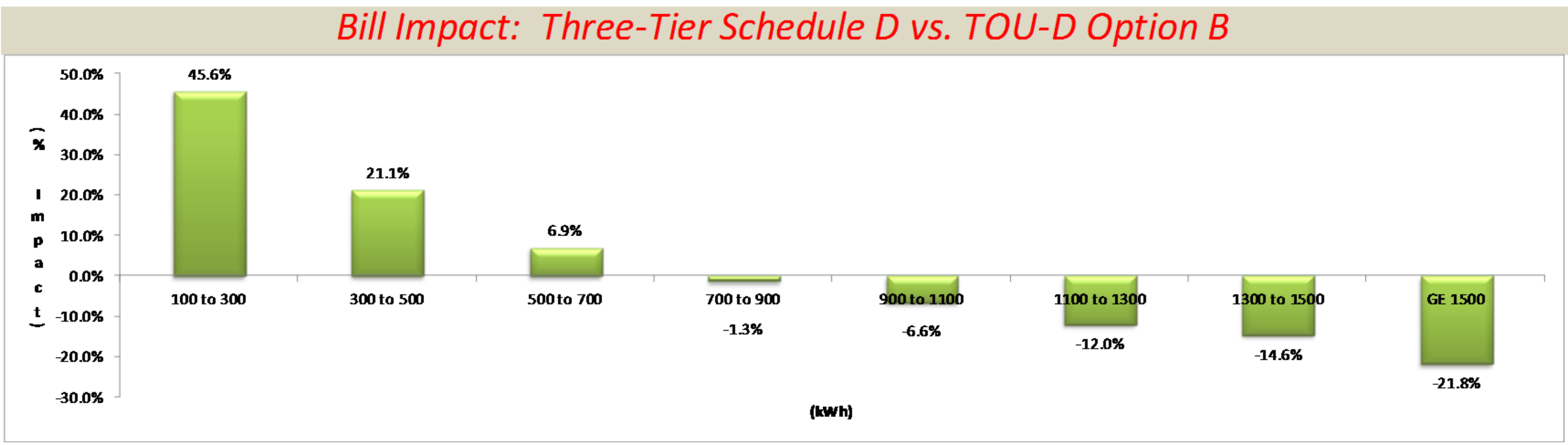
	October 2013 Rates			Proposed Rates			
	Delivery	Generation	Total Rate	Delivery	Generation	Total Rate	Total Rate Change
TOU-EV-4							
Energy Charge - $/kWh							
Summer Season On-Peak	0.02255	0.24060	0.26315	0.02255	0.24060	0.26315	0.0%
Mid-Peak	0.02255	0.08675	0.10930	0.02255	0.08675	0.10930	0.0%
Off-Peak	0.02255	0.02483	0.04738	0.02255	0.02483	0.04738	0.0%
Winter Season On-Peak	0.02255	0.07075	0.09330	0.02255	0.07075	0.09330	0.0%
Mid-Peak	0.02255	0.06041	0.08296	0.02255	0.06041	0.08296	0.0%
Off-Peak	0.02255	0.03371	0.05626	0.02255	0.03371	0.05626	0.0%
Customer Charge - $/meter/month	189.25		189.25	189.25		189.25	0.0%
Facilities Related							
Demand Charge - $/kW	12.32		12.32	12.32		12.32	0.0%
Time Related							
Demand Charge - $/kW	0.00	0.00	0.00	0.00	0.00	0.00	
Voltage Discount, Facilities Related Demand - $/kW							
From 2 kV to 50 kV	(0.18)	0.00	(0.18)	(0.18)	0.00	(0.18)	0.0%
From 51 kV to 219 kV	(5.64)	0.00	(5.64)	(5.64)	0.00	(5.64)	0.0%
220 kV and above	(9.49)	0.00	(9.49)	(9.49)	0.00	(9.49)	0.0%
Voltage Discount, Time-Related Demand - $/kW							
From 2 kV to 50 kV	0.00	0.00	0.00	0.00	0.00	0.00	
From 51 kV to 219 kV	0.00	0.00	0.00	0.00	0.00	0.00	
220 kV and above	0.00	0.00	0.00	0.00	0.00	0.00	
Voltage Discount, Energy - $/kWh							
From 2 kV to 50 kV	0.00000	(0.00103)	(0.00103)	0.00000	(0.00103)	(0.00103)	0.0%
From 51 kV to 219 kV	0.00000	(0.00229)	(0.00229)	0.00000	(0.00229)	(0.00229)	0.0%
220 kV and above	0.00000	(0.00231)	(0.00231)	0.00000	(0.00231)	(0.00231)	0.0%
Power Factor Adjustment - $/kVA							
Greater than 50 kV	0.34	0.00	0.34	0.34	0.00	0.34	0.0%
50 kV or less	0.51	0.00	0.51	0.51	0.00	0.51	0.0%

Appendix F

Bill Impacts of EV Rate Proposals

The histograms on this page correspond to the bill impacts in Tables III-9 and III-10 in the body of the testimony.





Appendix G

Analysis of Load Profiles for EV Charging

1. Description of Schedules On Which EV Customers Take Service

Residential EV owners in SCE's territory currently have the choice of charging their cars on schedules TOU-EV-1, TOU-D-TEV, or D.

The TOU-EV-1 rate is designed specifically for electric vehicle charging load metered with a separate meter. The second meter is installed at no additional cost, but the home's electrical infrastructure must be able to support the incremental load (however small or large), often at significant customer expense. For this rate plan, lower rates apply during the "off-peak" hours of 9:00 p.m. to 12:00 noon, and rates change seasonally. Rates are highest during the summer noon to 9:00 p.m. on-peak period.

Table G-I
TOU-EV-1 Time-of-Use Periods

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

The TOU-D-TEV rate is designed for residential customers who have their typical household load with electric vehicle charging on the same meter. This rate plan uses baseline allocations and a tiered structure similar to the standard residential rate. Currently, this rate plan has only two tiers, while the standard residential rate has four tiers. As with the standard rate plan, the cost per kilowatt hour rises as more electricity is used in a billing period. With this rate plan, rates change seasonally, with higher rates in summer to reflect the higher cost of generation capacity, and lower rates in winter when costs are lower. This rate offers energy prices for different TOU periods, and includes a super off-peak period where generation and distribution charges have been set to their marginal cost floor levels.

Table G-2
TOU-D-TEV Time Periods

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

The Domestic (D) rate is the standard residential rate. As of the filing of this application, this rate included four usage tiers with inclining block rates and baseline allocations that vary with climate zone.

2. Load Profiles and Analyses

A study of daily EV load profiles was performed by SCE's Load Research group using interval data for the twelve months preceding October 2013. Specifically, SCE has identified 6,395[45] service accounts belonging to EV owners. SCE then analyzed 1,341 accounts from this subpopulation after it excluded Net Energy Metering (NEM) accounts on a whole-house rate for which the date of acquisition of the vehicle was unknown, and accounts that participate in some incentive or discount program.

a) Separately metered plug-in electric vehicles (TOU-EV-1 rate)

EVs that are charged on a separate meter provide an unobscured view of usage and are readily identified. As such, the entire population of Schedule TOU-EV-1 accounts is analyzed. As shown in Table G-3 below, customers on this rate charge their vehicles primarily during the off-peak period.

Table G-3
TOU-EV-1 Customers On/Off-Peak Usage %

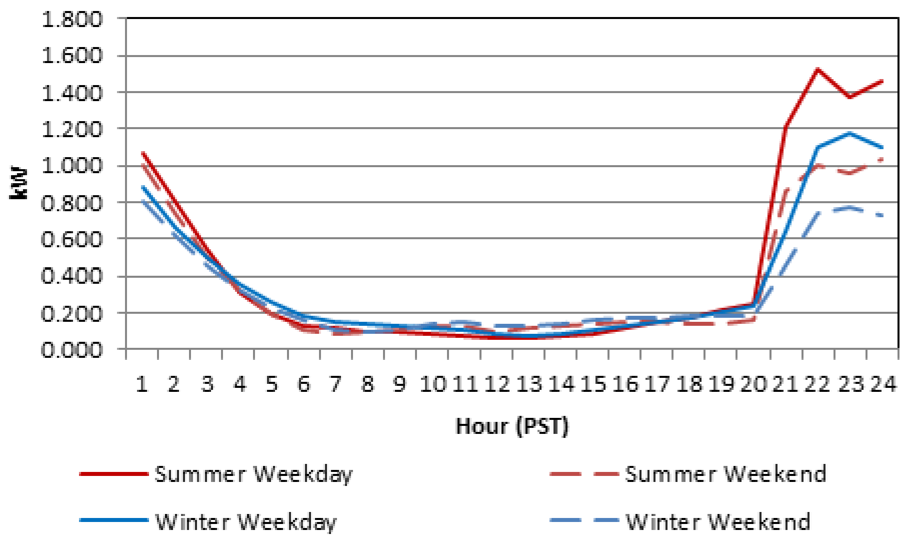
Off Peak (10:00 PM – 11:00 AM)	84%
On Peak (12:00 PM – 9:00 PM)	16%

Figure G-1 below shows that charging occurs almost exclusively between 10 p.m. and 6 a.m. There is a spike in EV load around 10 p.m. for TOU-EV-1 customers, suggesting that they are well aware that off-peak charging times begin at 9:00 p.m. Charging continues during the off-peak period, but tapers until it has leveled off at around 0.1 kWh at 6:00 a.m. This load shape appears consistent from season to season. Thus, customers on the TOU-EV-1 rate are prudent in their charging behaviors and the rate structure appears to be incentivizing charging during the defined off-peak hours. As

[45] This data was obtained through customer self-identification, Original Equipment Manufacturer (OEM)-shared data (with customer consent), and city/county electrical permits.

customers respond appropriately to the price incentive and start charging after 9:00 p.m., their peak occurs well after the residential class peak, which usually occurs between 4 p.m.-8 p.m.

Figure G-1
Average Daily Load Profile (TOU-EV-1)



There is lower demand between 10:00 p.m. and midnight during the weekend. In summer (June—September), average daily electric vehicle charging is 19% lower on the weekend than during the week, and 17% lower during the winter (October–May). This may be due to fewer customers charging during the weekends, fewer miles being driven on the weekends, or a wider variety of charging times among customers. These vehicles seem to be used mostly for the commute to work. The load profile metrics (*e.g.*, average daily usage, peak demand, etc.) for these customers are summarized in Table G-4.

Table G-4
Load Profile Metrics for Customers on Schedule TOU-EV-1[46]

	Summer		**Winter**	
	Weekday	Weekend	Weekday	Weekend
Daily Usage (kWh)	10.275	8.493	8.732	7.351
Peak demand (kW)	1.529	1.033	1.173	0.802
Time of Peak	10:00 PM	12:00 AM	11:00 PM	1:00 AM
Daily Load factor	0.280	0.342	0.310	0.382

b) Single metered house, plug-in electric vehicles inclusive (D, TOU-D-TEV)

SCE also reviewed usage data for customers who elected to charge their EV on their house meter under rate schedules D and TOU-D-TEV. The load profiles and metrics for these customers are summarized in Figure G-2 and Table G-5 below.

Figure G-2 shows that customers on the D rate have somewhat higher average usage compared to customers taking service on TOU-D-TEV. Customers on the D rate also tend to have more usage during the on-peak hours. The bump in the profiles occurring 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 TOU-D-TEV load profile also shows an increase in load around 12:00 a.m., which is most likely due to charging of the EV, and a high percentage of usage occurring during the super-off peak period. Furthermore, it appears that customers begin charging toward the end of the off-peak period and the majority of charging occurs during the super-off peak times (12:00 a.m. – 6:00 a.m.).

[46] There were 319 TOU-EV-1 accounts as of September 30, 2013.

Figure G-2
Average Daily Load Profiles
(single-metered rates post EV acquisition)

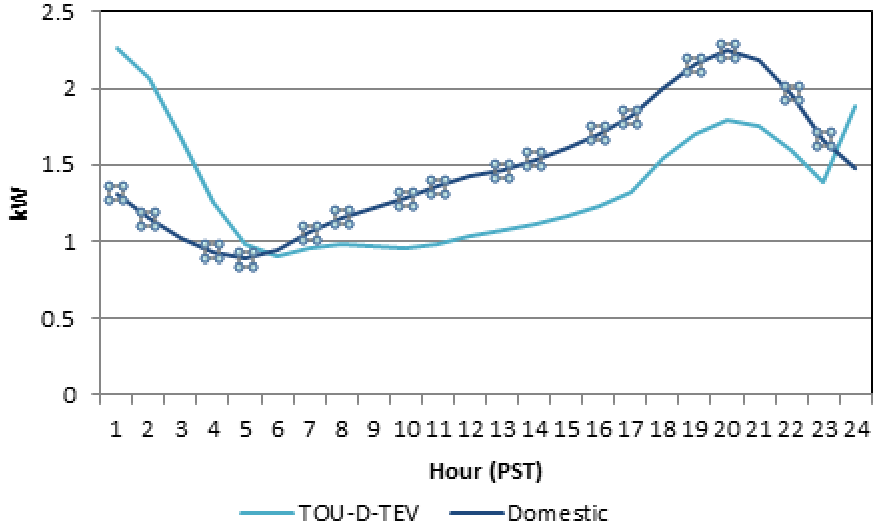


Table G-5
Load Profile Metrics for Customers on Schedules D and TOU-D-TEV

	D (n = 632)[47]	**TOU-D-TEV (n = 390[8])**
Daily Usage (kWh)	35.030	32.384
Peak demand (kW)	2.206	2.181
Time of Peak	8:00 PM	1:00 AM
Daily Load factor	0.662	0.619

[47] Non Net Energy Metering accounts with load data between October 1, 2012 and September 30, 2013 and a known delivery date of the electric vehicle.

Appendix H

Costs and Benefits of EV Integration and Charging

1. Marginal Cost of Electric Vehicle Load

While SCE does not know the actual charging levels for EVs to the extent they are charged behind the meter, the impact of an EV charging at level 1 (1.4kW) is not discernibly different from other basic household appliances. At higher charging levels, the EV can have the same demand as an electric oven, HVAC or electric dryer, but some EVs' charging levels are even higher.

Since the launch of the EV market at the end of 2010, SCE has been monitoring the impact of EV charging on the local distribution system. SCE has performed approximately 5,900 infrastructure checks at the addresses of known EV owners as of October 31, 2013. From these infrastructure checks, SCE identified and completed a total of eighteen Rule 15 and Rule 16 upgrades to transformers, secondaries and service drops. This represents 0.3% of the infrastructure checks performed. The average cost of these upgrades was $3,750 per project and ranged from $274 to $10,384 per project. Based on the number of infrastructure checks completed, the average cost per EV was $11 assuming 5,900 infrastructure checks. As of October 2013, SCE estimates that there are approximately 16,300 EVs in SCE's territory. Thus, based on this number of vehicles, the average cost of upgrades was $4 per EV. SCE completed 15 upgrades under Rule 16, which averaged $3,685 per project and ranged from $274 to $10,384 per upgrade.

In D.11-07-029, the Commission ordered the utilities to deviate from their normal practice and not bill EV customers for costs in excess of the Rule 15 and 16 allowances, a policy which has been extended through June of 2016 by D.13-06-014. However, to date, none of the upgrades completed by SCE has exceeded the standard Rule 16 allowances already authorized by the Commission. SCE will continue to monitor infrastructure upgrade projects associated with EVs and any excess billings to help inform future policies regarding the allocation of any significant upgrade costs.

As a point of reference, in 2010, Dr. Robert Levin, Public Utilities Regulatory Analyst of the Office of Ratepayer Advocates for the California Public Utilities Commission, predicted that EVs would cause an upgrade to be completed for 10% of all EVs with an average cost of $500.[48] At the time D.11-07-029 was issued in 2011, there was a general expectation that the increased load from EVs would require significant infrastructure upgrades. To date, that has not happened.

Although SCE believes there may be incremental marginal costs associated with EV adoption in the future as some customers might adopt higher charging levels, at this point the cost data does not indicate a need for special rate treatment, including the addition of demand charges, for owners of EVs to distinguish the costs of serving EV loads from those of other equipment.

2 <u>Benefits of Electric Vehicle Loads</u>

There are several significant societal benefits to electrifying transportation, especially passenger vehicles in California.[49] Although the market for EV adoption is still considered nascent, there are efforts underway to quantify the benefits of EV load on the grid, assuming appropriate charging behavior, which assumes that vehicles charge during generally off-peak periods when the marginal cost of generation is low. This further assumes that most of the vehicles receive appropriate cost-based price signals to incentivize charging during cheaper super off-peak time periods. In the new AFV OIR (R.13-11-007), the Commission has identified vehicle-to-grid benefits as an area of study over the next few years, which will provide further insight into the benefits of EVs to the grid assuming the necessary technologies mature.

SCE recognizes these potential benefits and, based on generally accepted ratemaking principles, proposes to update the designs of the residential EV rates to help capture these external benefits. SCE's rate proposals, discussed in Section III.D above, accomplishes this by simplifying the TOU rates, eliminating tiers, providing TOU options for lower usage customers, expanding super off-

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[48] Levin, Robert D, *Electric Vehicles: A Ratepayer Perspective.* May 2010. http://www.dra.ca.gov/uploadedFiles/Content/Energy/Climate/Electric_Vehicles_2010July3.pdf

[49] "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." D 11-07-029. p. 3.

peak charging periods, and pricing the Generation charge in these periods at marginal cost while recovering some Distribution-related costs through fixed charges.

Appendix I

Analysis of Consumer Responses to EV Rates' TOU Price Differentials

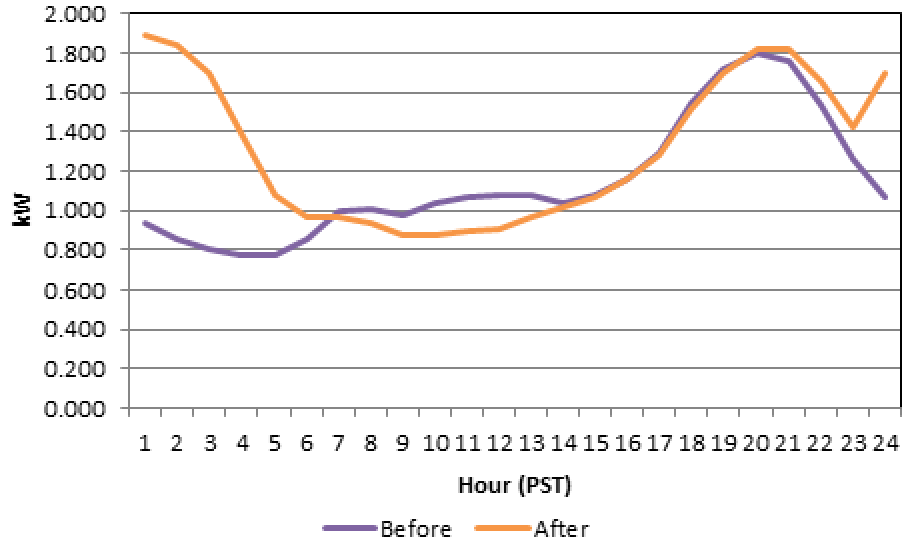
A rigorous analysis of customer behavior and responsiveness to TOU price differentials would require controlling for confounding factors (*e.g.*, variables affecting the determination of why customers charge during which times, for reasons other than price) which would be most reliably achieved through a designed study. However, two ad-hoc methods with which the responsiveness to TOU price differentials may be evaluated are: 1) through observing how customers modify their behavior once they switch to a rate with a different TOU structure and 2) by comparing the behavior of customers using different rate structures.

a) <u>Method 1: Comparison of profiles before and after EV acquisition for the same customers</u>

For identified EV owners, where the approximate date they acquired the electric vehicle was also available, load profiles were constructed for both before and after the acquisition. These load profiles show the impact of EVs and the owners' charging behaviors assuming that electricity demands other than those of EVs remain the same. The charging behaviors can then be compared between those owners who remain on the Schedule D rate and those owners who choose to switch from the Schedule D rate to the TOU-D-TEV rate.

Customers who move to a TOU rate from the regular residential tiered rate have an early evening peak which is very similar to the peak before they acquired the EV. However, they show a second, greater peak in the early morning which can be attributed to their EV. As shown in Figure I-1, this second peak occurs after midnight when the super-off- peak charging period begins. Additionally, there is some evidence of a shift in usage away from the on-peak hours, *i.e.*, 12:00 p.m. to 8:00 p.m. If such a shift does occur, a plausible explanation would be that once customers are on a TOU rate, they respond to the price differentials between the periods even for their non-EV load.

Figure I-1
Load Profiles Before and After EV Acquisition
(Switching from Domestic to TOU-D-TEV)



For customers who remained on Schedule D, which has no TOU price differential, an additional load also occurs in the evening to early morning as shown in Figure I-2. This additional load is assumed to be for EV charging and would suggest that cars are primarily used for the commute to work since there is a smaller degree of change in usage during the middle of the day.

Table I-1 provides summary statistics (average daily usage, peak demand, time of peak, etc.) for EV customers who remain on the domestic rate, before and after EV acquisition.

Figure I-2
Load Profiles Before and After EV Acquisition
(D rate, not switching)

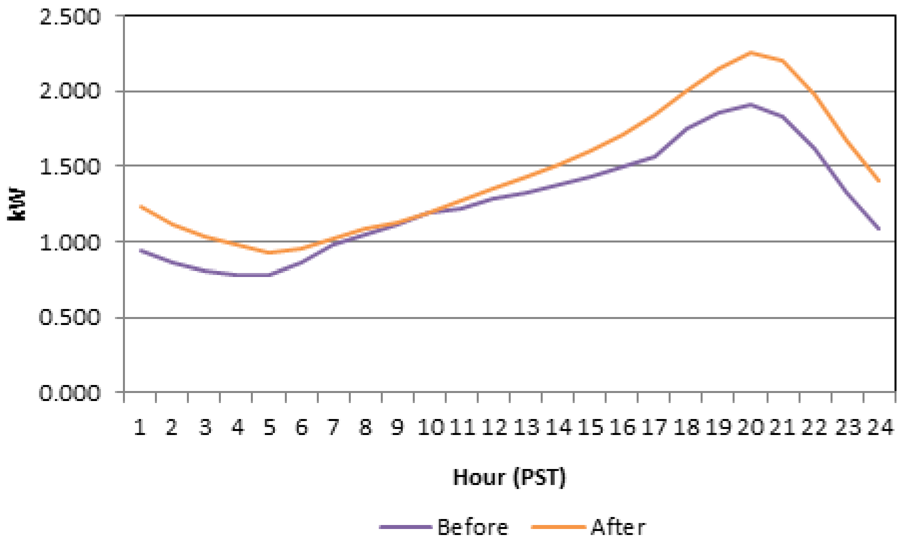


Table I-1
Usage Characteristics for
EV Customer Remaining on Schedule D

	TOU-D_TEV (n = 104[50])		**DOMESTIC (n = 394[51])**	
	before	after	before	after
Daily Usage (kWh)	27.486	31.437	30.449	35.066
Peak demand (kW)	1.803	1.890	1.913	2.251
Time of Peak	8:00 PM	1:00 AM	8:00 PM	8:00 PM
Daily Load factor	0.635	0.693	0.663	0.649

50 Non-Net Energy Metering accounts with load data between Oct. 1, 2012 and Sep. 30, 2013. Account must have switched to the TOU rate within thirty days of the delivery date (prior or post) of the vehicle. For each account observations were limited to an equal number of days before and after delivery.

51 Non-Net Energy Metering accounts with load data between Oct. 1, 2012 and Sep. 30, 2013 and a known delivery date of the electric vehicle. For each account observations were limited to an equal number of days before and after delivery.

San Diego Gas and Electric Company's (SDG&E's) Electric Vehicle pilot more rigorously studies the charging behavior of Nissan Leaf owners on a TOU rate under three different price ratios. First-year findings from this experiment can be found in the 2012 'Joint Report' appendix that describes the pilot:

> 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 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. 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." [52]

a) Method 2: Comparison of profiles across customers on different rates

This approach compares the charging behaviors of EV customers that are receiving service on different rate structures. For this analysis, SCE compared EV customers' charging behavior under the three different rates available to these customers: D, TOU-D-TEV, and TOU-EV-1. The daily electric vehicle usage for the single meter rate groups was estimated as the difference in usage of the cohort before and after acquisition of the plug-in electric vehicle whereas that usage was directly measured for the TOU-EV-1 group.

The estimated electric vehicle profiles suggest that customers adhere to the most economical charging times of their chosen rate structure. As residential charging occurs almost exclusively in the evening and early morning, it is useful to consider their load profiles centered during that time. This allows the full, aggregated charging cycles to be observed. To illustrate this, Figure I-3 shows load profiles for EV customers with the hours of the day beginning at 1 p.m. and ending at 1 p.m. the next

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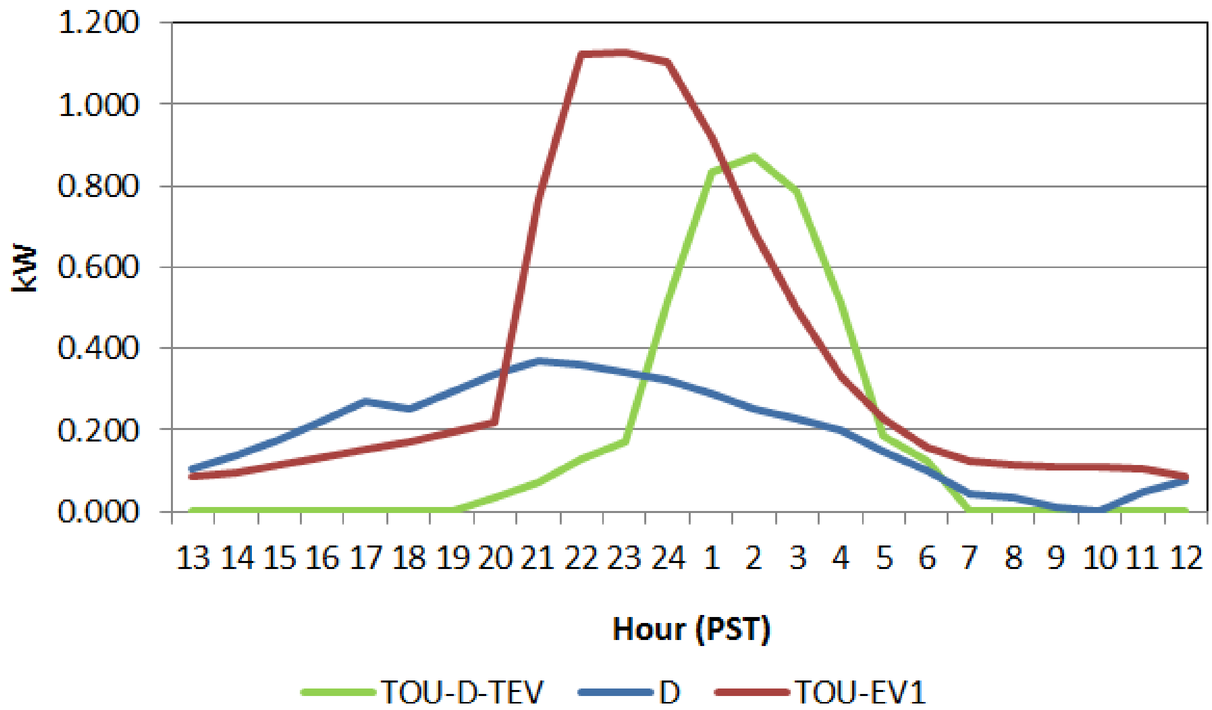
[52] Joint IOU Electric Vehicle Load Research Final Report, Filed on December 28, 2012 Appendix A.

day. This view is a shift from the usual daily profiles in which the day starts at midnight and ends the following midnight.

Figure I-3
EV Charging Profiles by Rate Schedule
(estimated for D and TOU-D-TEV[53]



Two conclusions can be drawn from the data illustrated in Figure I-3: First, demand increases markedly beginning on the hour when the cheapest price begins which is 9 p.m. for the EV-only TOU-EV-1 rate and 12 a.m. for the single meter, TOU-D-TEV rate. Lacking any price signal, the EV charging on the whole house D rate ramps up in the early evening, likely when the customers arrive home after work. Second, the duration of the high load varies, which also appears to be the result of the

[53] For the TOU-D-TEV rate, where the assumed usage shift produces negative electric vehicle usage (between the hours of 7 a.m. and 1 p.m.) the electric vehicle demand is set to zero. This assumed non-electric vehicle load is then subtracted uniformly from the super off-peak hours of the estimated electric vehicle profile. This assumes a demand shift rather than conservation and accounts for the minimum amount of household demand would have shifted.

respective rate structures. A longer charging time is observed for customers on the Schedule D rate. Customers charging electric vehicles at Level 1 would require longer charging times and possibly find the super off-peak charging window for the whole house TOU rate too narrow to achieve full charging. Those using the whole house TOU rate nearly completely curtail demand as the super off-peak period ends while those charging on a dedicated meter show a more gradual decline in load, likely because the vehicles reach their capacity and cycle off well within their lowest cost period.

It is important to consider that the TOU rates are optional and customers are likely to select a rate which meets their charging requirements and preferences. For example, most customers on a single-household meter with high non-electric vehicle daytime usage that is not easily shifted would likely find a TOU rate unattractive. Also, some EV owners may drive fewer miles over the course of a week and thus require less charging and consequently derive less benefit from lower off-peak pricing. Additionally, customers who require a longer charging period or have a regular need to charge outside of the early morning hours may not find certain TOU rate structures advantageous. For some customers, the costs associated with installing a separate meter may preclude them from taking service on the TOU-EV-1 rate.

The EV Project, designed and managed by ECOtality North America, studies, in part, the behavior of Nissan Leaf and Chevrolet Volt owners using Level 2 electric vehicle supply equipment (EVSE) charging stations.[54] A report for the first quarter of 2013 compared the behavior of EV owners served by various utilities under different rate structures.

The study draws examples from three service territories in the U.S.; Nashville Electric Service (NES), Pacific Gas & Electric (PG&E), and Portland General Electric (PGE) and observes similar results to the previous analysis. EV owners in NES service territory, where a TOU rate is not offered, predominantly began charging in the early afternoon and tapered off by 3 a.m. In PG&E's service area where a high percentage of EV owners are on a TOU rate the peak demand occurs after midnight,

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[54] 'How do PEV owners respond to time-of-use rates while charging EV Project vehicles?', July, 2013 http://www.theevproject.com/cms-assets/documents/125348-714937.pev-driver.pdf

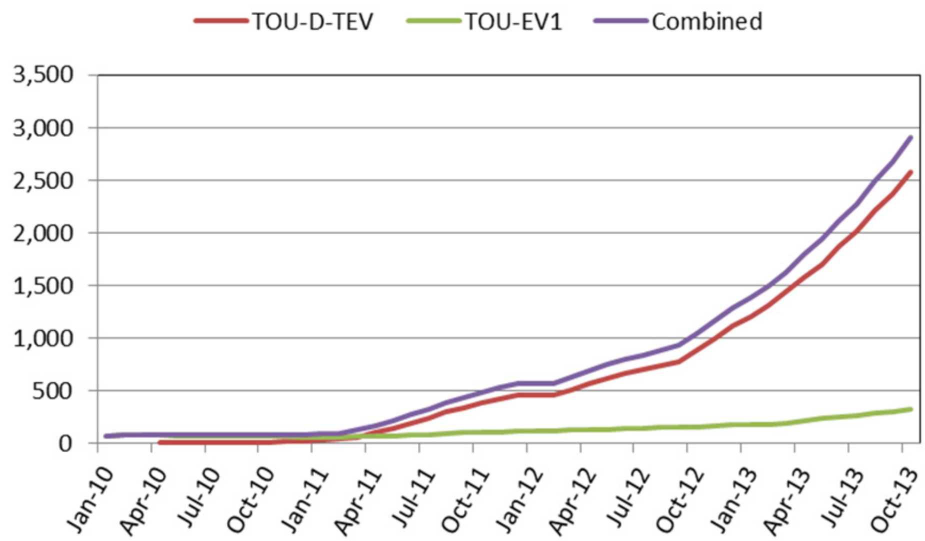
corresponding to the off-peak rates, while the early evening demand remains muted. In PGE's service area TOU rates are also offered, however there is a low adoption of the TOU rates and the data shows that only some of the evening load is shifted to later in the off-peak times.

They find that "the financial incentives appear to successfully shift EV charging demand to off-peak hours. However, it also appears that TOU incentive was more effective in the PG&E service territory than in the PGE territory".

1. Trends

Monthly numbers of accounts with EVs are only available for the TOU rates explicitly designed with the EV in mind. Figure I-4 illustrates how the number of accounts on these rates has been increasing exponentially. Most of the growth is occurring in the single-meter TOU rate, TOU-D-TEV, presumably due to the cost and inconvenience of adding the second meter (and possible panel upgrades) required for service on Schedule TOU-EV-1. Also, the separate meter may not be attractive to customers who lease their vehicle and may perceive the possession of the EV as temporary.

Figure I-4
Number of Plug-in Electric Vehicle Accounts 2010 - 2013



The growth in the number of accounts taking service on the separately-metered TOU-EV-1 rate has been more stable, and the average daily load profile is strikingly similar in shape from 2010 through nine months of 2013 as shown in Figure I-5 and Table I-2.

Figure I-5
Average Daily Load Profiles by Year (TOU-EV-1)

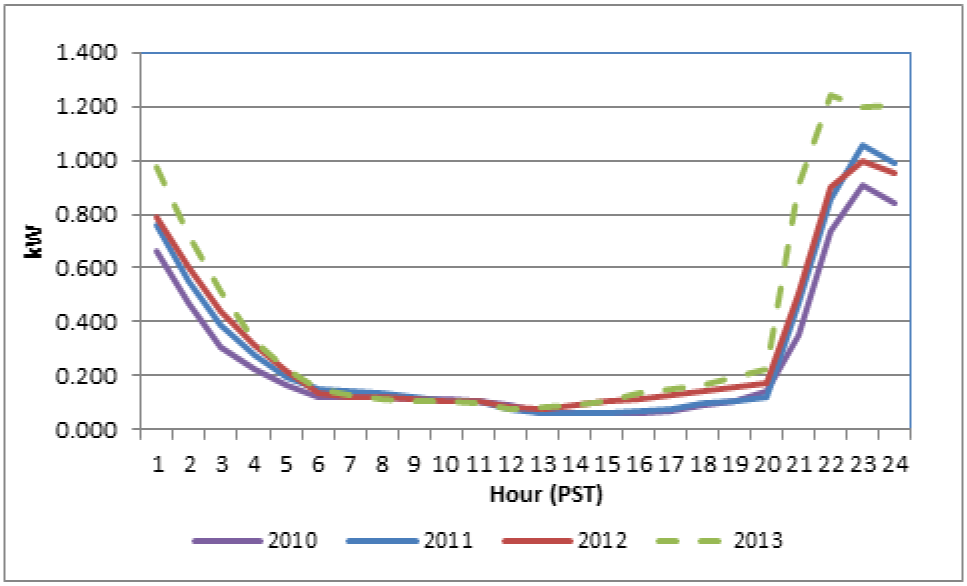


Table I-2
Load Profile Metrics for TOU-EV-1 Customers

	2010 (n = 46)	2011 (n = 106)	2012 (n = 169)	2013[55] (n = 319)
Daily Usage (kWh)	6.121	7.056	7.506	9.270
Peak demand (kW)	0.905	1.060	0.997	1.243
Time of Peak	11:00 PM	11:00 PM	11:00 PM	10:00 PM
Daily Load factor	0.282	0.277	0.314	0.311

The above table shows that even though the number of accounts quadrupled between 2010 and 2012, the peak demand remained nearly constant and the time of peak has stayed the same. The load data year-to-date for 2013 indicates a profile very similar to the prior years. We observe a mild increase in usage over the timeframe. However, caution should be used when drawing conclusion on the exact measurements in 2013 as the data excludes three winter months. Figure I-5 indicates that usage is lower

[55] Data for 2013 is for the partial year through September 30, 2013.

in the winter and the fact that these winter months are predominantly on Pacific Standard Time could cause the peak demand which now appears at 10 p.m. to shift to 11 p.m. as seen with the previous full years of data. It appears that over time the daily charging pattern of TOU-EV-1 customers has remained constant, but the frequency of charging has increased, an indication that EV use becoming more regular.

2. <u>Load Research Conclusions</u>

The number of EV owners has been increasing steadily, but these owners are still considered early adopters. The statistics and trends presented here are informative and applicable to early adopters but caution should be exercised when extrapolating to the behavior of future EV owners as technology, policies and customer demographics can change.

Estimated EV load profiles show that charging occurs after work hours and not necessarily daily, suggesting that the vehicle is still used mostly for commuting, a hypothesis bolstered by the observation that there is more charging diversity on weekends.

Load research estimates indicate that on average plug-in electric vehicle owners with higher usage, presumably resulting from more frequent use of the electric vehicle, opt for rates which yield more value and are more accommodating to charging. Customers who elect a TOU rate respond to the price signals and charge their vehicles during the period with the lowest price. As the number of EV owners grows, the usage of the vehicles also seems to grow, an indication that the EV is becoming more of a utilitarian transportation tool. The result is an observed growth in the adoption of the TOU rates.

It is also worth noting that the average daily usage for customers who remain on the standard domestic rate after acquiring an EV is slightly greater than that of customers who switch to a time-of-use rate, and this difference holds true both before and after acquisition.

It is possible that customers with regular air conditioning load and higher daily usage could be reluctant to adopt TOU rates that have higher on-peak prices. Lower TOU price differentials and better communication of bill impacts may encourage those customers to make the switch to a TOU plan.

EV customers who adopt a TOU rate are demonstrating consistent and rational usage behavior. These customers are responding well to TOU price signals and charge their EVs primarily during the off-peak hours. EV customers who remain on the standard D rate do not receive TOU price signals and are less likely to restrict vehicle charging to the off-peak period.

Appendix J

Demand Charges

Based on the results of SCE's examination of EV load additions in the residential sector, including infrastructure upgrade frequency and cost data, SCE does not find the need to implement demand charges on optional residential rates at this time. As stated in Appendix H above, SCE believes there may be incremental marginal costs associated with EV adoption in the future as some customers might adopt higher charging levels, but at this point the cost data does not indicate a need for adding demand charges for owners of EVs to distinguish the costs of serving EV loads from those of other equipment.

With respect to the commercial EV rates, however, SCE explains in Section III.E above how it proposes to continue assessing demand charges in Schedule TOU-EV-4, and how it proposes to revise Schedule TOU-EV-3 to mirror the same structure to prevent customers from paying two demand charges for the same premises on which a commercial EV is being charged. Customers on commercial non-EV rates are already sensitized to demand charges, so proposing to keep them in Schedule TOU-EV-4—and making those charges consistent with TOU-EV-3—is reasonable from a customer service and cost-causation perspective.

SCE anticipates further study and discussion of demand charges will be conducted in R.13-11-007.