REPORT

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2019 Load Impact Evaluation of Southern California Edison's Default Time-of-Use Pilot

Prepared for:

Southern California Edison Co.

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1 Executive Summary

This report documents the 2019 load impact evaluation of Southern California Edison's Residential Default Time-of-Use (TOU) pricing pilot. This pilot was implemented in response to California Public Utilities Commission (CPUC) Decision 15-07-001. A key objective of the pilot is to develop insights that will help guide SCE's approach to implementation of default TOU pricing for the majority of residential electricity customers and the CPUC's policy decisions regarding default pricing.

Findings from the first summer of the pilot—June through September 2018—are documented in the "Default Time-Of-Use Pricing Pilot Interim Evaluation" dated April 1, 2019 (hereafter referred to as the Interim Report). The Interim Report contains detailed background information on the pilot, describes the pilot design and the load impact evaluation methodology, discusses SCE's pilot implementation and treatments, and presents load impacts for the first summer period. It also presents structural bill impacts and summarizes pre-enrollment opt-out rates. Findings from the first winter and the full first year of the pilot are documented in the "Default Time-Of-Use Pricing Pilot Final Evaluation" dated November 1, 2019 (hereafter referred to as the Final Report). The Final Report focuses primarily on load impacts from the winter period in 2018 and 2019 as well as bill impacts for the first year of the pilot. The winter results provide load impacts for the entire winter rate period of October 2018 through May 2019. Behavioral bill impacts and total bill impacts are provided for the full first year of the pilot, from June 2018 through May 2019. Customer attrition throughout the first year is also included in the Final Report.

The primary objective of this report is to document the findings of an ex post (after the fact) study that estimates hourly load impacts for the summer of 2019 (June through September 2019). An additional objective is to provide an ex ante (forward looking) forecast for the next eleven years (2020 to 2030) of program operations. The ex ante study provides estimated hourly load impacts given SCE's default TOU enrollment forecast and given weather conditions that reflect SCE and California Independent System Operator (CAISO) electric system peaks.

1.1 Pilot Background and Design

The default TOU pilot tested two different TOU rate options: Rate 4 and Rate 5. Approximately 400,000 households were assigned to one of the TOU rates (200,000 to each rate), and an additional 200,000 were retained in the study on the standard tiered rate to act as a control group for those who were placed on the new tariffs. After receiving multiple notifications regarding the fact that their rate will change if they did not take action by a certain date, customers had the option of opting out prior to the rate change and staying either on their otherwise applicable tariff or choosing an alternative rate plan other than the one they were to be defaulted on. If a customer took no action, they were placed on the default rate associated with their assigned group.

Figure 1-1 and Figure 1-2 summarize the rate periods and prices for Rates 4 and 5. Importantly, the prices shown in the figures and discussed below do not reflect the baseline credit of 8¢/kWh that applies to each rate.

Figure 1-1 Default Pilot Rate 4[1]

Day Type	Season	Hour Ending																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Weekday	Summer	Off-Peak (23¢)																Peak (42¢)							
	Winter	Off-Peak (29¢)								Super Off-Peak (18¢)								Mid-Peak (30¢)							
Weekend	Summer	Off-Peak (23¢)																Mid-Peak (27¢)							
	Winter	Off-Peak (29¢)								Super Off-Peak (18¢)								Mid-Peak (30¢)							

Figure 1-2: Default Pilot Rate 5

Day Type	Season	Hour Ending																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Weekday	Summer	Off-Peak (24¢)																	Peak (51¢)						
	Winter	Off-Peak (30¢)								Super Off-Peak (18¢)									Mid-Peak (32¢)						
Weekend	Summer	Off-Peak (24¢)																	Mid-Peak (30¢)						
	Winter	Off-Peak (30¢)								Super Off-Peak (18¢)									Mid-Peak (32¢)						

The pilot was structured as a randomized encouragement design (RED) experiment. With a RED, different randomly selected samples of customers are offered different experimental treatments (in this case, a TOU rate or different content or messaging in the recruitment materials) and another random group of customers is not offered anything (e.g., the control group). Some who are offered the treatment take it and some do not. Because each sample is a statistical clone of the other due to the random selection (especially in this case where sample sizes are quite large), comparing the behavior of the encouraged group with that of the control group allows for an unbiased assessment of the impact of the treatment. This analysis requires a two-step process in order to isolate the impact of the encouragement (e.g., the offer of a treatment) from the treatment itself, as explained more fully in Section 3.1.

Load impacts were estimated for four different climate regions in SCE's service territory (hot, moderate, cool, and Climate Zone 10). For the moderate and cool climate regions, estimates were also made for two customer segments, CARE/FERA customers and non-CARE/FERA customers. CARE/FERA customers in the hot climate region and Climate Zone 10 were not allowed to be enrolled on TOU tariffs using default recruitment. As such, comparisons across the two hot and two more moderate regions not only reflect differences in climate but also differences in the mix of customers. Also, differences in load impacts across customer segments at the service territory level reflect not just differences across segments, but also differences in the mix of customers across climate regions for each segment. These differences must be kept in mind when making comparisons across segments and climate regions. Load impacts were also estimated for each Local Capacity Area (LCA) in SCE's service territory and for net metered and non-net metered customers.

[1] Rates effective June 1, 2019

1.2 Overall Findings

1.2.1 Ex Post Load Impacts

Table 1-1: Peak Period Load Reductions on Average Weekday

Utility	Metric	Rate 4	Rate 5
SCE	Peak Period Hours	4-9 PM	5-8 PM
	% Impact	1.3%	1.7%
	Absolute Impact (kW)	0.02 kW	0.02 kW

Key findings pertaining to the ex post analysis include:

- On average, default customers on both Rates 4 and 5 produced statistically significant, peak-period load reductions. Peak period load reductions averaged roughly 1.3% for Rate 4 and 1.7% for Rate 5.
- Load reductions for the common hours shared by the two rates (5 to 8 PM) were greater for Rate 5 than for Rate 4, likely because of the higher peak period price per kWh. It's also possible the shorter peak period of Rate 5 allowed for greater flexibility in customer response to the price signal. The difference was statistically significant for the territory as a whole, the moderate climate region, and the cool climate region.
- Statistically significant but small reductions in daily electricity use were found for both rates and in all climate regions except for customers on Rate 4 in the moderate climate region. It appears that the average customer in SCE's service territory was more likely to reduce overall usage during the peak period rather than shift usage to off-peak hours.
- The pattern of load reductions across climate regions in absolute terms was consistent between the two rates but was slightly different in percentage terms. Absolute peak period load reductions were largest in Climate Zone 10 and the hot climate region regions, but these segments did not include CARE/FERA customers. Absolute impacts were smallest in the cool climate region, which included CARE/FERA and non-CARE/FERA customers.
- In the cool climate region, non-CARE/FERA customers typically had statistically significantly greater peak period impacts compared to CARE/FERA customers. In the moderate climate region on Rate 4 and Rate 5, the difference between CARE/FERA and non-CARE/FERA customers was not statistically significant.
- For the first time, load impacts were estimated by LCA region. The LA Basin region is the largest region, yet it had the smallest load reductions compared to the Outside LA Basin region and Ventura/Big Creek region for both rates.

1.2.2 Persistence of Load Impacts

Key findings pertaining to the persistence analysis include:

- On average, customers on Rate 4 and Rate 5 produced statistically significant load reductions in summer 2018 and summer 2019. At the service territory level, load impacts were smaller in the second summer, and the difference was statistically significant. Customers on Rate 4 had load reductions equal to 1.5% in the first summer and 1.2% in the second summer. Rate 5 peak period impacts were 1.9% in 2018 and 1.5% in 2019. While the weather was slightly cooler on average in 2019 compared to 2018, the load impacts were lower in 2019 at comparable temperatures indicating second summer impacts were slightly lower when accounting for differences in weather.
- The load impacts for the different climate regions on the two rates were generally smaller in the second summer compared to the first summer. Exceptions include customers on Rate 4 in the hot climate region and Climate Zone 10 who load impact increases from year to year, but the differences are not statistically significant.
- CARE/FERA customers in the cool climate region on Rate 4 had the most notable reduction in peak period load impacts. Load impacts in the first summer were equal to 0.9% and were statistically significant. In the second summer, load impacts for this customer segment were equal to 0.2% and were not statistically significant.

1.2.3 Ex Ante Load Impacts

Key findings pertaining to the ex ante analysis include:

- Enrollment on Rate 4 is expected to grow from approximately 130,000 in 2020 to over 2.1 million in 2030 as new waves of default customers are added to the rate. Enrollment on Rate 5 is expected to gradually decline through customer turnover from about 130,000 to 40,000 in 2030.
- Generally speaking, ex post and ex ante load impacts are larger under higher temperatures. As such, the largest ex ante impacts (over 0.02 kW per customer) are forecasted for 1-in-10 weather conditions during the hottest summer months (July, August, and September) for both Rate 4 and Rate 5. Winter ex ante load impact estimates are expected to be similar under 1-in-2 and 1-in-10 weather conditions.
- The ex ante load impacts under SCE 1-in-2 weather conditions are similar to the ex post load impact estimates. This finding is expected as the average monthly temperatures are similar between October 2018 through September 2019 and the ex ante weather conditions. The temperatures under 1-in-10 weather condition are warmer than the ex post weather conditions; therefore, the load impacts under the 1-in-10 conditions are expected to be greater than the ex post load impacts.
- In 2022 after the default is completed, Rate 4 impacts are forecasted to reach nearly 50 MW on the average August weekday under SCE 1-in-10 weather conditions and over 40 MW under SCE 1-in-2 weather conditions. Rate 5 impacts during the RA window under SCE 1-in-10 weather conditions decline from a peak of 2.6 MW in August 2020 to 0.9 MW in August 2030 as the population grows smaller.

2 Introduction

The SCE Residential Default TOU pilot tested two different TOU rate options beginning in the spring of 2018. Approximately 400,000 households were assigned to one of the TOU rates (200,000 to each rate), and an additional 200,000 were retained in the study on the standard tiered rate to act as a control group for those who were placed on the new tariffs. After receiving multiple notifications regarding the fact that their rate will change if they did not take action by a certain date, customers had the option of opting out prior to the rate change and staying either on their otherwise applicable tariff or choosing an alternative rate plan other than the one they were to be defaulted on. If a customer took no action, they were placed on the default rate associated with their assigned group. The initial default notifications are described in detail in Section 2.2 of the Interim Report. These notifications included a rate analysis comparing each customer's bill based on the new TOU rate with their bill under the otherwise applicable tariff using historical customer data along with additional education and outreach (E&O) material.

Findings from the first summer of the pilot—June through September 2018—are documented in the "Default Time-Of-Use Pricing Pilot Interim Evaluation" dated April 1, 2019 (hereafter referred to as the Interim Report). The Interim Report contains detailed background information on the pilot, describes the pilot design and the load impact evaluation methodology, discusses SCE's pilot implementation and treatments, and presents load impacts for the first summer period. It also presents structural bill impacts and summarizes pre-enrollment opt-out rates. Findings from the first winter and the full first year of the pilot are documented in the "Default Time-Of-Use Pricing Pilot Final Evaluation" dated November 1, 2019 (hereafter referred to as the Final Report). The Final Report focuses primarily on load impacts from the winter period in 2018 and 2019 as well as bill impacts for the first year of the pilot. The winter results provide load impacts for the entire winter rate period of September 2018 through May 2019. Behavioral bill impacts and total bill impacts are provided for the full first year of the pilot, from June 2018 through May 2019. Customer attrition throughout the first year of the pilot is also included in the Final Report.

Figure 2-1 and Figure 2-2 summarize the rate periods and prices for Rates 4 and 5. Importantly, the prices shown in the figures and discussed below do not reflect the baseline credit of 8¢/kWh that applies to each rate.

Figure 2-1 Default Pilot Rate 4[2]

Day Type	Season	Hour Ending																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Weekday	Summer	Off-Peak (23¢)																Peak (42¢)							
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	Winter	Off-Peak (29¢)								Super Off-Peak (18¢)								Mid-Peak (30¢)							

Figure 2-2: Default Pilot Rate 5

Day Type	Season	Hour Ending																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Weekday	Summer	Off-Peak (24¢)																	Peak (51¢)						
	Winter	Off-Peak (30¢)								Super Off-Peak (18¢)									Mid-Peak (32¢)						
Weekend	Summer	Off-Peak (24¢)																	Mid-Peak (30¢)						
	Winter	Off-Peak (30¢)								Super Off-Peak (18¢)									Mid-Peak (32¢)						

Rate 4 has two rate periods on summer weekdays and three on winter weekdays. The peak and mid-peak period on Rate 4 is the same all year long and runs from 4 PM to 9 PM. The peak to off-peak price ratio (ignoring the baseline credit) is 1.8 to 1 in summer and mid-peak to super off-peak ratio is 1.7 to 1 in winter. Customers on SCE's Rate 4 pay super off-peak prices on weekdays and weekends in the winter. In summer, off-peak prices are in effect on weekends from 9 PM to 4 PM, which is the time-period covered by the combination of off-peak and super off-peak prices during winter.

SCE's Rate 5 has two rate periods on summer weekdays and three on winter weekdays, the same structure as Rate 4. Compared with Rate 4, Rate 5 has a much shorter peak period but a slightly higher peak price in summer months (51¢/kWh for Rate 5 versus 42¢/kWh for Rate 4) and slightly high mid-peak price in winter months (32¢/kWh for Rate 5 versus 30¢/kWh for Rate 4). The peak period runs from 5 PM to 8 PM. Rate 5 also features a super off-peak price of roughly 18¢/kWh between 8 AM and 5 PM on weekdays and weekends during winter. The ratio of peak to off-peak prices in the summer is roughly 2.1 to 1. In winter, the mid-peak to super off-peak price ratio is roughly 1.8 to 1. On weekends, customers pay the off-peak price between 8 PM and 8 AM and the super off-peak price during the same overnight hours as on weekdays, from 8 AM to 5 PM. For the two rates, the summer season covers the months of June through September. The winter season is October through May.

Load impacts were estimated for four different climate regions in SCE's service territory (hot, moderate, cool, and Climate Zone 10). For the moderate and cool climate regions, estimates were also made for two customer segments, CARE/FERA customers and non-CARE/FERA customers. CARE/FERA customers in the hot climate region and Climate Zone 10 were not allowed to be enrolled on TOU tariffs using default recruitment. As such, comparisons across the two hot and two more moderate regions not only reflect differences in climate but also differences in the mix of customers. Also, differences in load impacts across customer segments at the service territory level reflect not just differences across segments, but also differences in the mix of customers across climate regions for each segment. These differences must be kept in mind when making comparisons across segments and climate regions. Load

[2] Rates effective June 1, 2019

impacts were also estimated for each Local Capacity Area (LCA) in SCE's service territory and for net metered and non-net metered customers.

2.1 Evaluation Objectives

The primary objectives of the 2019 D-TOU load impact evaluation are to:

- Estimate hourly ex post load impacts for the summer period from June to September 2019;
- Forecast 2020-2030 D-TOU hourly ex ante load impacts for 1-in-2 and 1-in-10 year weather conditions by month – in the aggregate and per customer – for utility-specific and CAISO peak conditions;
- Estimate ex post and ex ante load reductions for each climate region (hot, moderate, cool, and Climate Zone 10), pilot segment (non-CARE/FERA and CARE/FERA), and SCE local capacity area (LCA)
- Transparently document the process through which ex post estimate are used to develop ex ante forecasts; and
- Conduct the evaluation and produce all evaluation reporting in compliance with the California Public Utilities Commission (CPUC) Load Impact Protocols (Protocols)[3] and under guidance provided by the Demand Response Measurement and Evaluation Committee (DRMEC).

2.2 Overview of Methods

The pilot was structured as a randomized encouragement design (RED) experiment. With a RED, different randomly selected samples of customers are offered different experimental treatments (in this case, a TOU rate or different content or messaging in the recruitment materials) and another random group of customers is not offered anything (e.g., the control group). Some who are offered the treatment take it and some do not. Because each sample is a statistical clone of the other due to the random selection (especially in this case where sample sizes are quite large), comparing the behavior of the encouraged group with that of the control group allows for an unbiased assessment of the impact of the treatment. This analysis requires a two-step process in order to isolate the impact of the encouragement from the treatment itself. The first stage ITT impact was estimated using a difference-in-differences (DiD) regression model. In the second analysis step, the ITT estimate is divided by the percent of the encouraged group who take up the treatment offer. This value represents the impact for those who took the treatment (referred to as the impact of the treatment on the treated).[4]

The persistence analysis, which examines how load impacts change from year to year, uses the same approach but is limited to a specific group of customers who were active SCE customers from the launch of the pilot through the end of September 2019.

[3] California Public Utilities Commission Decision 08-04-050 issued on April 28, 2008 with Attachment A.

[4] This second stage calculation relies on an assumption that decliners are not influenced by the fact that they received an offer. If, for example, decliners shifted load simply because they received an offer to go on a new rate, load impact estimates for non-decliners would be biased upward.

The ex ante evaluation incorporates information from the first winter (October 2018 through May 2019) and second summer (June through September 2019) of the pilot. Nexant developed a simple impact model that estimates how default TOU ex post load impacts vary as a function of temperature. To produce the ex ante load impact forecasts, Nexant applied this temperature-load impact relationship to profiles representing normal (1-in-2) and extreme (1-in-10) weather conditions. Two sets of ex ante weather conditions are used: one based on utility-specific system peak conditions, and one based on California Independent System Operator (CAISO) system peak conditions. In total, there are four estimates of ex ante load impacts: two representing normal weather with temperatures selected based on utility-specific and CAISO peak conditions, and two representing extreme weather with temperatures again based on SCE and CAISO conditions.

2.3 Report Organization

The remainder of this report is organized as follows:

- Section 3 describes the methodology used to estimate ex post impacts;
- Section 4 presents post-enrollment opt-out rates;
- Sections 5 and 6 present ex post impacts and the persistence of load impacts; and
- Section 7 presents ex ante estimates.

3 Methodology

This report provides ex post load impacts for the Summer 2019 period (June 1, 2019 through September 30, 2019), and ex ante impacts for 1-in-2 and 1-in-10 year weather conditions for 2020 through 2030. The persistence of load impacts for customers who remained active accounts from the launch of the pilot through the end of September 2019 is also reported. Post-enrollment opt-out rates for each climate region and customer segment are also reported in Section 4. This section summarizes the methodological approaches used to estimate the metrics of interest for each customer segment. The discussion is organized into three broad sections summarizing the approach for estimating ex post load impacts, the persistence of load impacts, and ex ante load impacts.

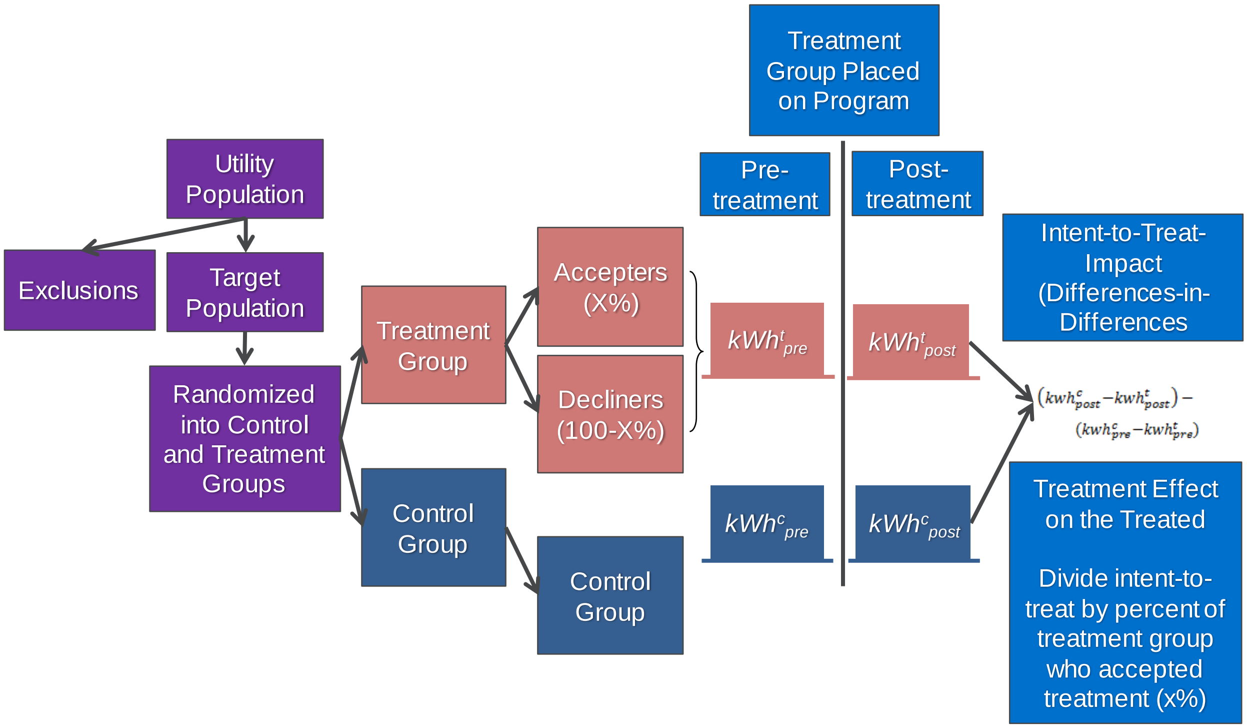
3.1 Ex Post Load Impacts Methodology

The estimation of ex post load impacts by rate period and changes in daily energy use for each pilot rate are key pilot objectives. Also of interest is how load impacts vary across climate regions and customer segments (e.g., non-CARE/FERA customers and CARE/FERA customers) for two of the four climate regions, since CARE/FERA customers could not be defaulted in the two hot climate regions. Ex post load impacts are also reported for each LCA in SCE's service territory and for net metered (NEM) and non-net metered (non-NEM) customers. The approach used to estimate load impacts is summarized below.

As discussed in the previous section, the pilot involves a randomized encouragement experimental design. With a RED structure involving a single rate treatment of interest (for simplicity), the study sample is randomly divided into two groups. One group is offered the treatment and the other is not. The group offered the treatment is referred to as the encouraged group and the group not offered the treatment is referred to as the control group. Some people in the encouraged group will accept the treatment and others will not. With a RED, impacts for those who accept the treatment offer are estimated through a two-step process. In the first step, loads by time period for the encouraged group are subtracted from loads for the control group. As stated above, the encouraged group includes both those who accept the encouragement (that is, those who enroll on the new rate) and those who do not. The estimated load impact based on these two groups of customers is referred to as the intention-to-treat (ITT) effect. In the second analysis step, the ITT estimate is divided by the percent of the encouraged group who take up the treatment offer. This value represents the impact for those who took the treatment (referred to as the impact of the treatment on the treated).[1] A conceptual overview of the RED design and analysis for estimating load impacts is shown in Figure 3-1.

[1] This second stage calculation relies on an assumption that decliners are not influenced by the fact that they received an offer. If, for example, decliners shifted load simply because they received an offer to go on a new rate, load impact estimates for non-decliners would be biased upward.

Figure 3-1: Design and Analysis Schematic for a RED Experiment



For the pilot, the first stage ITT impact was estimated using what is called a difference-in-differences (DiD) analysis. This method estimates impacts by subtracting treatment customers' loads (or in this first stage, the encouraged customers' loads) from control customers' loads in each hour or time period after the treatments are in place and subtracts from this value the difference in loads between treatment and control customers for the same time period in the pretreatment period. Subtracting any difference between treatment and control customers prior to the treatment going into effect adjusts for any difference between the two groups that might occur due to random chance.

The DiD calculation can be done arithmetically using simple averages or can be done using regression analysis. Customer fixed effects regression analysis allows each customer's mean usage to be modeled separately, which reduces the standard error of the impact estimates without changing their magnitude. Additionally, regression software allows for the calculation of standard errors, confidence intervals, and significance tests for load impact estimates that correctly account for the correlation in customer loads over time.[2] Implementing a DiD through simple arithmetic would yield the same point estimate but it would not generate confidence intervals.

[2] More accurately, they account for the correlation in regression errors within customers over time.

A typical regression specification for estimating impacts is shown in Equation 3-1.

Equation 3-1: Ex Post Load Impact Model Specification

$$kW_{i,t} = \alpha_i + \delta \mathrm{treat}_i + \gamma \mathrm{post}_t + \beta (\mathrm{treatpost})_{i,t} + \ v_i + \ \varepsilon_{i,t}$$

In the above equation, the variable $\mathrm{kW}_{\mathrm{i,t}}$ equals electricity usage during the time period of interest, which might be each hour of the day, peak or off-peak periods, daily usage or some other period. The index i refers to customers and the index t refers to the time period of interest. The estimating database would contain electricity usage data during both the pretreatment and post-treatment periods for both treatment (encouraged) and control group customers. The variable treat is equal to 1 for treatment customers and 0 for control customers, while the variable post is equal to 1 for days after the TOU rate has been implemented and a value of 0 for days during the pretreatment period. The treat post term is the interaction of treat and post and its coefficient β is a difference-in-differences estimator of the treatment effect that makes use of the pretreatment data. The primary parameter of interest is β, which provides the estimated demand impact during the relevant period. The parameter a_{i} is equal to mean usage for each customer for the relevant time period (e.g., hourly, peak period, etc.). The v_{i} term is the customer fixed effects variable that controls for unobserved factors that are time-invariant and unique to each customer.

Customer attrition is an important factor to address in the load impact analysis. Customer attrition stems from four factors; customers who move (referred to as churn); customers who become ineligible after enrolling in the pilot; customers who opted out before the pilot began, and customers who dropped off the rate after enrollment because they were unhappy being on the TOU rate. Customer churn and changes in eligibility should be the same for both treatment and control customers. As such, dropping customers from both treatment and control groups due to churn and changes in eligibility does not introduce selection effects.

The majority of load impact estimates reported in Section 5 are based on a comparison of loads between each treatment group and the control group. Estimates for customer segments and climate regions are developed by first partitioning the treatment and control groups into samples for each climate region and/or customer segment of interest and then applying the analysis method outlined above to the partitioned data.

The load impact estimates reported here conform to the requirements for ex post evaluation of non-event based demand response resources as indicated in California's Demand Response Load Impact Protocols.[3] These protocols require that load impacts in each hour be developed for the average weekday and monthly system peak days for each month of the year. Although not explicitly required by the protocols, load impacts for the average weekend day are also developed for each month of the year given that the TOU rates are also effective on the weekends. As this is an ex post analysis, average weekday impacts are based on the observed customer load pooled across the weekdays in each month, and similarly for weekend days. Monthly system peak day impacts are estimated based on loads that occur on the historical

[3] http://www.calmac.org/events/FinalDecision_AttachementA.pdf

monthly system peak days. Load impacts are presented in both nominal (kW) and proportional (%) terms.

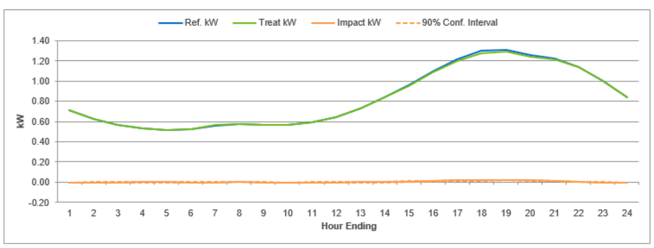
Figure 3-2 displays an image from an Excel spreadsheet containing the output that is produced for each rate treatment, customer segment, climate region, day type, and month covered by this interim analysis. These Excel spreadsheets are available upon request through the CPUC. Pull down menus in the upper left hand corner of the spreadsheet allow users to select different customer segments, climate regions, day types (e.g., weekdays, weekends, monthly peak day) and time period (individual months or the average of June, July, August and September). In this written report, tables and graphs are presented that report estimated load impacts by treatment, rate period, customer segment, and day type for the summer period.

The experimental design and sampling were constructed so that load impacts and other metrics can be reported for selected customer segments and climate regions. For the segments around which the pilots were designed, load impacts are estimated using the model represented in the equation above for the data partitioned by segment (for both treatment and control customers). These estimates are internally valid by virtue of the RED design and DiD analysis.

Figure 3-2: Average Hourly Load Impact Estimates for Rate 4

Select Options Below	
Rate:	Rate 4
Segment:	All
Time Period:	Summer
Day Type:	Average Weekday

Period	Control Customers	Treatment Customers	Ref. kW	Treat kW	Impact kW	90% Conf. Interval		% Impact
Peak	168,091	130,239	1.26	1.24	0.02	0.02	0.02	1.3%
Mid-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Off-Peak	168,091	130,239	0.71	0.71	0.00	0.00	0.00	0.0%
Super Off-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Day (kWh)	**168,091**	**130,239**	**19.87**	**19.79**	**0.08**	**0.06**	**0.10**	**0.4%**



Hour	Period	Ref. kW	Treat kW	Impact kW	% Impact	Weighted Temp. (°F)	Uncertainty-adjusted Impact - Percentiles				
							10th	30th	50th	70th	90th
1	Off-Peak	0.71	0.71	0.00	-0.4%	67.9	0.00	0.00	0.00	0.00	0.00
2	Off-Peak	0.62	0.63	0.00	-0.4%	67.2	0.00	0.00	0.00	0.00	0.00
3	Off-Peak	0.57	0.57	0.00	-0.2%	66.6	0.00	0.00	0.00	0.00	0.00
4	Off-Peak	0.53	0.53	0.00	-0.1%	66.1	0.00	0.00	0.00	0.00	0.00
5	Off-Peak	0.52	0.52	0.00	-0.1%	65.6	0.00	0.00	0.00	0.00	0.00
6	Off-Peak	0.53	0.53	0.00	-0.2%	65.2	0.00	0.00	0.00	0.00	0.00
7	Off-Peak	0.56	0.56	0.00	-0.3%	65.0	0.00	0.00	0.00	0.00	0.00
8	Off-Peak	0.58	0.58	0.00	0.1%	65.2	0.00	0.00	0.00	0.00	0.00
9	Off-Peak	0.57	0.57	0.00	-0.4%	66.8	0.00	0.00	0.00	0.00	0.00
10	Off-Peak	0.57	0.57	0.00	-0.7%	69.5	-0.01	-0.01	0.00	0.00	0.00
11	Off-Peak	0.59	0.59	0.00	-0.5%	72.5	-0.01	0.00	0.00	0.00	0.00
12	Off-Peak	0.64	0.65	0.00	-0.2%	75.5	-0.01	0.00	0.00	0.00	0.00
13	Off-Peak	0.73	0.73	0.00	0.1%	77.8	0.00	0.00	0.00	0.00	0.01
14	Off-Peak	0.84	0.84	0.00	0.2%	79.5	0.00	0.00	0.00	0.00	0.01
15	Off-Peak	0.96	0.95	0.01	0.6%	80.7	0.00	0.00	0.01	0.01	0.01
16	Off-Peak	1.09	1.08	0.01	0.8%	81.5	0.00	0.01	0.01	0.01	0.01
17	Peak	1.21	1.20	0.02	1.4%	81.5	0.01	0.02	0.02	0.02	0.02
18	Peak	1.30	1.28	0.02	1.4%	80.7	0.02	0.02	0.02	0.02	0.02
19	Peak	1.31	1.29	0.02	1.5%	79.2	0.02	0.02	0.02	0.02	0.02
20	Peak	1.26	1.24	0.02	1.3%	76.8	0.01	0.02	0.02	0.02	0.02
21	Peak	1.22	1.21	0.01	1.0%	73.8	0.01	0.01	0.01	0.01	0.01
22	Off-Peak	1.14	1.14	0.00	0.3%	71.3	0.00	0.00	0.00	0.00	0.01
23	Off-Peak	1.00	1.00	0.00	-0.2%	69.8	0.00	0.00	0.00	0.00	0.00
24	Off-Peak	0.84	0.84	0.00	-0.4%	68.8	-0.01	0.00	0.00	0.00	0.00

3.2 Persistence of Load Impacts Methodology

An important focus of investigation for the default pilot is whether impacts persist from year to year. When analyzing persistence, it is important to compare load impacts for the same group of customers over time. A comparison of load impacts for customers enrolled in 2018 with those enrolled in 2019 is not a valid estimate of persistence since any observed difference might be due in large part to changes in the participant population rather than changes in behavior of customers that participated in both summer periods.

As such, load impacts for the persistence analysis pertain to the population of customers that remained active SCE accounts over the entire period starting in April 2018 through the end of September 2019. The same methodology used to estimate ex post load impacts was used to estimate load impacts for this specific group of customers. As such, customers who opted out are retained in the analysis dataset to maintain the RED. While there is not a second winter for persistence comparison, the winter impacts for the subset of customers who were active for the full duration of the pilot are included with the two summer impacts to illustrate the relative differences in impacts between the summer and winter seasons for a common set of customers.

3.3 Ex Ante Load Impacts Methodology

Ex ante load impacts represent what the default TOU rates can deliver under a standardized set of weather conditions given changes in enrollment over the forecast horizon. The weather used for ex ante load impact estimation is meant to reflect conditions on average weekdays and monthly system peak days under both normal (1-in-2 years) and extreme (1-in-10 years) weather. Ex ante load impacts reflect the current Resource Adequacy (RA) window that runs from 4:00 PM to 9:00 PM and is in effect during all months of the year.[4] This is the same as the peak period for Rate 4, but includes two hours outside the Rate 5 peak period (5:00 to 8:00 PM)

At a high level, ex ante impact estimates for default TOU were developed using the following multi-step process:

- First, weekly ex post load impacts from October 2018 through September 2019 were developed using the fixed effects regression methodology described in Section 3.1;
- Next, the relationship between ex post load impacts and temperature is estimated for each hour of the day, each season (summer/winter) and each customer segment and rate;
- Then, ex ante weather conditions are used as input to the regression models to predict impacts for each hour for the average weekday and monthly system peak days from January through December.

3.3.1 Estimating Ex Ante Weather Conditions

The CPUC Load Impact Protocols[5] (Protocols) require that ex ante load impacts be estimated assuming weather conditions associated with both normal and extreme utility operating conditions. Normal conditions are defined as those that would be expected to occur once every 2 years (1-in-2 conditions) and extreme conditions are those that would be expected to occur once every 10 years (1-in-10 conditions).

Starting in 2008, the IOUs have based the ex ante weather conditions on system operating conditions specific to each individual utility. However, ex ante weather conditions could alternatively reflect 1-in-2 and 1-in-10 year operating conditions for the California Independent System Operator (CAISO) rather than the operating conditions for each IOU. While the Protocols are silent on this issue, a letter from the CPUC Energy Division to the IOUs dated October 21, 2014, directed the utilities to provide impact estimates under two sets of operating conditions starting with the April 1, 2015 filings: one reflecting operating conditions for each IOU and one reflecting operating conditions for the CAISO system.

In order to meet this new requirement, California's IOUs contracted with Nexant to develop ex ante weather conditions based on the peaking conditions for each utility and for the CAISO system. The previous ex ante weather conditions for each utility were developed in 2015 and were updated in 2019 along with the development of the new CAISO based conditions. Both

[4] The RA window was changed to the current window in June 2018 by order of the CPUC in D.18-06-030. The prior RA window was 1:00 to 6:00 PM in the summer and 4:00 to 9:00 PM in the winter.

[5] See CPUC Rulemaking (R.) 07-01-041 Decision (D.) 08-04-050, "Adopting Protocols for Estimating Demand Response Load Impacts" and Attachment A, "Protocols."

sets of estimates use a common methodology, which is documented in a report delivered to the IOUs.[6]

The extent to which utility-specific ex ante weather conditions differ from CAISO ex ante weather conditions largely depends on the correlation between individual utility and CAISO peak loads, which varies across the IOUs. SCE's peaking conditions are strongly correlated with CAISO's.

3.3.2 Estimate Ex Ante Load Impacts

Ex ante impact estimates were calculated by making predictions for ex ante weather conditions using a regression model of ex post impacts from 2018 and 2019. As noted in Section 3.3.1, the ex ante weather conditions were updated in 2019 and were chosen to be representative of 1-in-2 and 1-in-10 year for the SCE and CAISO specific operating conditions using the most recent load and weather data available at the time.

The ex ante model specification takes as its dependent variable the average hourly ex post impact for each week from October 2018 through September 2019. The independent variables for each hour were the average temperature for the hour of interest and a binary indicator for the calendar month. There is a positive relationship between temperature and load impacts; as temperatures rise, so do load impacts. The model specification is presented in Equation 3-2:[7]

Equation 3-2: Hourly Ex Ante Load Impact Model Specification

$$Impact_h = a + b \cdot temperature_h + \sum_{i=1}^{12} c_i \cdot month_{hi} + \boldsymbol{\varepsilon}$$

Table 3-1: Description of Ex Ante Load Impact Regression Variables

Variable	Description
$Impact_h$	Per customer ex post load impact for each week, for the hour h
a	Estimated constant
b	Estimated parameter coefficient
c	Estimated parameter coefficient
$temperature_h$	Average during the hour *h* for the average weekday in each week
$month_{hi}$	A binary indicator for each month *i* of the year, January through December, for the hour *h* of interest
$\boldsymbol{\varepsilon}$	The error term, assumed to be a mean zero and uncorrelated with any of the independent variables

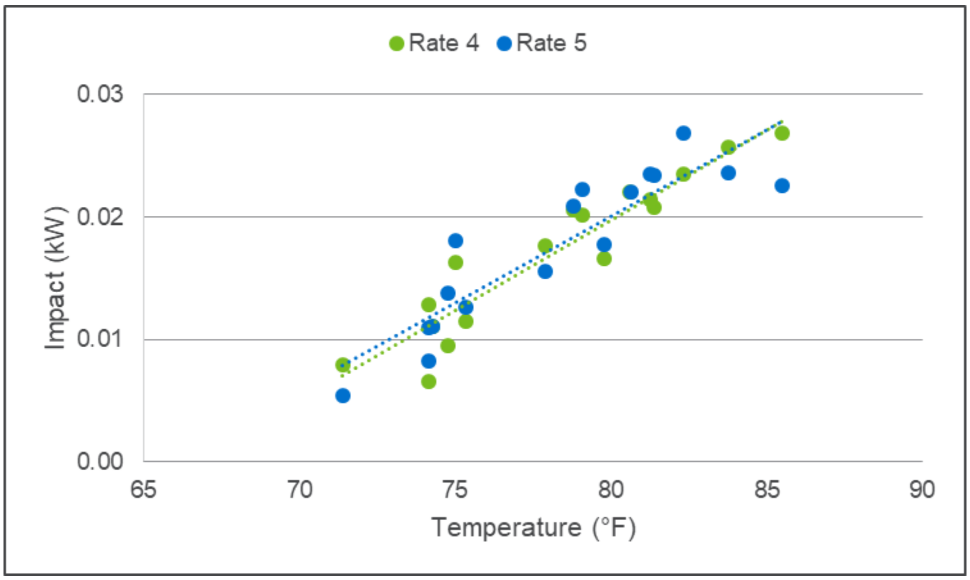
[6] See *Statewide Demand Response Ex Ante Weather Conditions*. Nexant, Inc. January 30, 2015.

[7] Nexant has used similar model specifications in a number of load impact evaluations. It was originally chosen based on extensive validation analysis of many different model specifications conducted in conjunction with these prior evaluations.

While the ex post impacts presented in this report are estimated at the seasonal and monthly level, the impacts use to build the ex ante model were estimated at the weekly level. The purpose of more granular impact estimates is to maximize the number of data points available for estimation. The ex ante model is estimated separately for each LCA and rate, and predictions from the model are then made separately for each LCA and rate's individual ex ante weather conditions.

Figure 3-3 illustrates the relationships between summer peak period temperatures and per customer load impacts for Rate 4 and Rate 5 customers. Similar relationships of ex post load impacts are estimated for each the winter season and for each LCA.

Figure 3-3: Peak Period Ex Post Impact versus Temperature – Rate 4 and Rate 5



4 Customer Attrition

This section summarizes customer post-enrollment opt-out rates for each rate tested by SCE. As discussed in Section 3.3 of the Interim Report, an analysis of customer opt-out rates can provide useful insights concerning relative customer preferences among the rates.

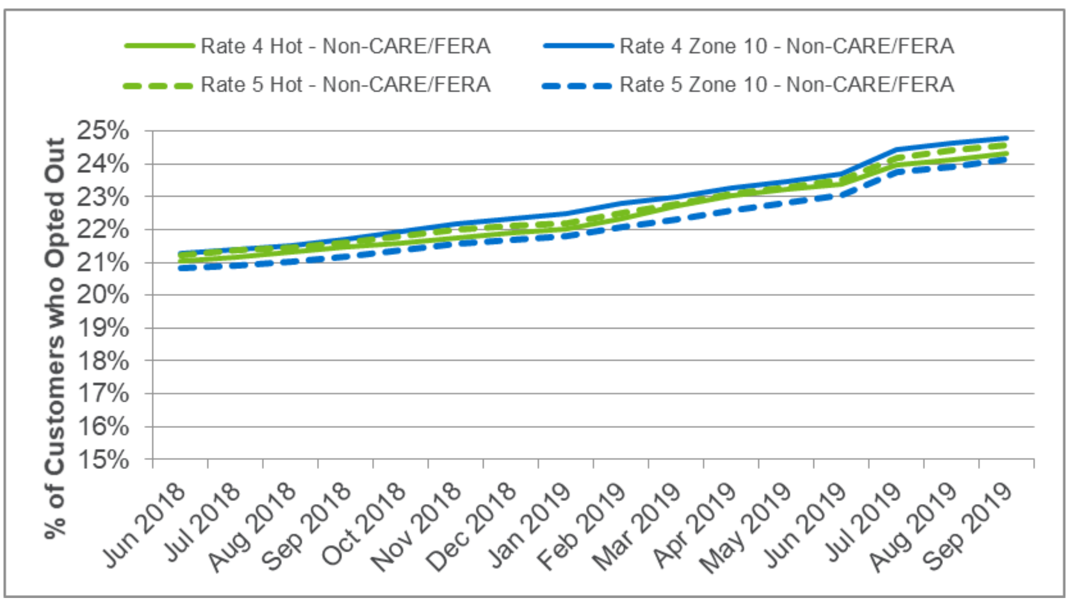
4.1 Post-enrollment Opt-Outs

Post-enrollment opt-out rates were very small during the period following enrollment through the end of the second summer of the pilot (September 2019). Cumulative opt-out rates are presented for the post-enrollment period for each climate region and CARE/FERA status in Figure 4-1, Figure 4-2, and

Figure 4-3. Generally any difference in cumulative opt-out rates between segments occurred during the pre-treatment period. Post-enrollment opt-out rates for all customer segments were between 2.2% and 3.5%. Post enrollment opt-out rates are lowest in the cool climate region and highest in Climate Zone 10. Within the moderate climate region, Rate 4 and Rate 5 customers have nearly identical post-enrollment opt-out rates.

Bill protection for customers ended in March or April of 2019, depending on the individual customer's billing cycle. The end of bill protection did not result in any not noticeable increase in customer opt-outs from the pilot rates. SCE should continue to monitor customer opt-outs in order to better understand customer participation trends for the eventual full default TOU rollout.

Figure 4-1: Cumulative Opt-Out Rates for Hot and Zone 10 Climate Regions[1]



[1] Opt-out rates here present customers who opted out to the OAT, not those who opted out into the alternate rate.

Figure 4-2: Cumulative Opt-Out Rates for Moderate Climate Region

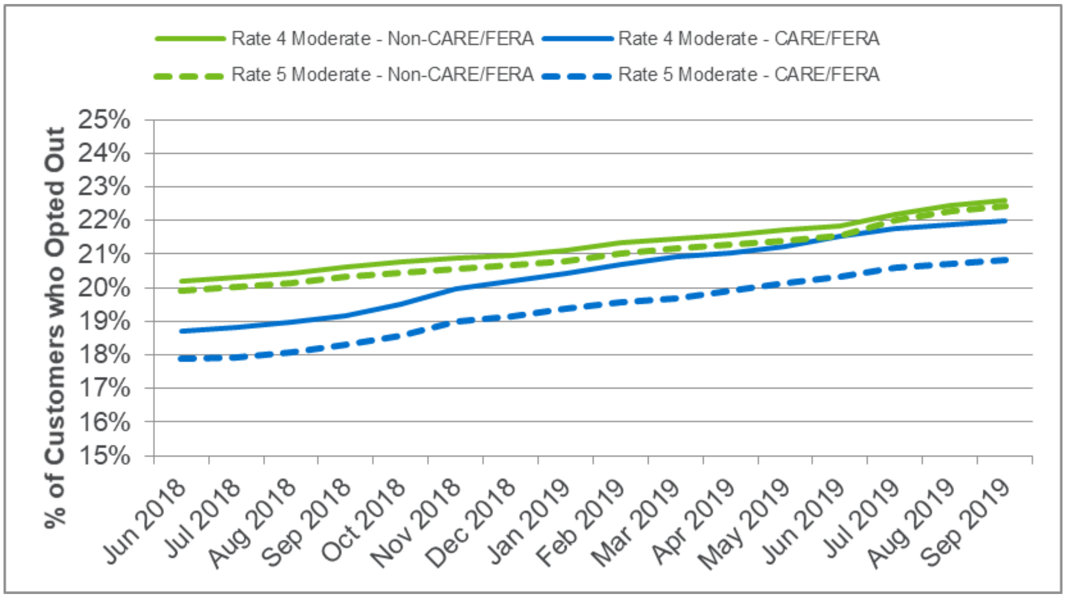
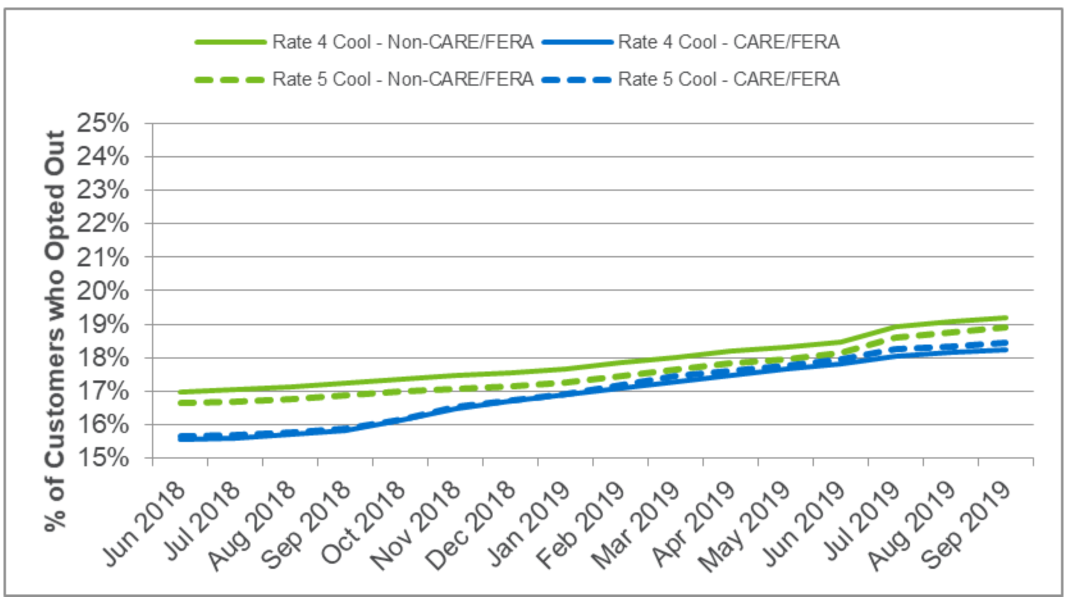


Figure 4-3: Cumulative Opt-Out Rates for Cool Climate Region



5 Ex Post Load Impacts

This report section summarizes the load impacts for the two rate treatments tested by SCE. Load impacts were estimated for the peak and off-peak periods and for average hourly and daily energy use for the following rates, customer segments, and climate regions:

- For all customers on each rate for the pilot population as a whole and for all customers in each climate region (hot, moderate, cool, and Climate Zone 10);
- Non-CARE/FERA customers on each rate for the pilot population as a whole and across climate regions (hot, moderate, cool, and Climate Zone 10) and CARE/FERA customers in the moderate and cool climate regions;
- For all customers on each rate in each LCA (LA Basin, Outside LA Basin, and Ventura/Big Creek); and
- Non-net metered and net metered customers.

As discussed above, it's imperative that comparisons across regions and climate zones are cognizant of the differences in the mix of customers across regions. That is, because CARE/FERA customers are not included in the two hot climate regions, comparisons of load impacts across the two hot and two cooler regions reflect not only differences due to climate but also differences in the mix of customers, with both CARE/FERA and non-CARE/FERA customers in the moderate and cool regions and only non-CARE/FERA customers in the two hot regions. Similarly, comparisons across customer segments for the service territory as a whole do not just reflect differences in behavior between CARE/FERA and non-CARE/FERA customers but also differences in the mix of customers across climate regions. The all utility impacts are representative of what SCE can expect at the service territory level for full roll out of the rates, because CARE/FERA customers will not be defaulted in the hot climate regions for full roll out. But, it is not appropriate to claim that a difference of, say, 50% between CARE/FERA and non-CARE/FERA customers at the service territory level accurately reflects a difference in behavior between the two groups of customers, all other factors held constant.

Ex post load impacts are reported here for each rate period for the average weekday, average weekend, and average monthly peak day for the summer months of June through September 2019. Impacts are reported for each rate, climate region, customer segment and LCA summarized above.

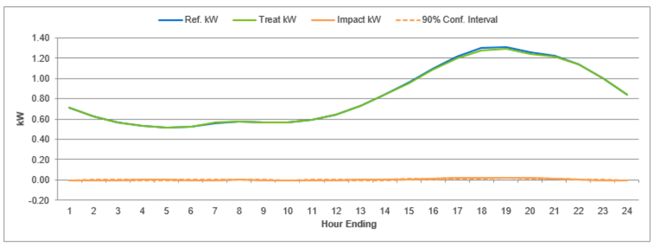
Underlying the values presented in the report are electronic tables that contain estimates for each hour of the day for each day type, segment, and climate region for the summer; and for each month separately. These values are contained in Excel spreadsheets that are available upon request through the CPUC. Figure 5-1 shows an example of the content of these electronic tables for SCE Rate 4 for all eligible customers in the service territory. Pull down menus in the upper left hand corner allow users to select different customer segments, climate regions, day types (e.g., weekdays, weekends, monthly peak day) and time periods (individual months or seasons).

The remainder of this section is organized by rate treatment—load impacts are presented for each relevant customer segment and climate region for each of the two rates. Load impacts are also presented for each LCA and for net metered and non-net metered customers. Finally, comparisons of load impacts across the two TOU rates are made for the common hours (5 PM to 8 PM) that are shared across rates.

Figure 5-1: Example of Content of Electronic Tables Underlying Load Impacts Summarized in this Report (SCE Rate 4, Average Summer 2019 Weekday, All Customers)

Select Options Below	
Rate:	Rate 4
Segment:	All
Time Period:	Summer
Day Type:	Average Weekday

Period	Control Customers	Treatment Customers	Ref. kW	Treat kW	Impact kW	90% Conf. Interval		% Impact
Peak	168,091	130,239	1.26	1.24	0.02	0.02	0.02	1.3%
Mid-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Off-Peak	168,091	130,239	0.71	0.71	0.00	0.00	0.00	0.0%
Super Off-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Day (kWh)	**168,091**	**130,239**	**19.87**	**19.79**	**0.08**	**0.06**	**0.10**	**0.4%**



Hour	Period	Ref. kW	Treat kW	Impact kW	% Impact	Weighted Temp. (°F)	Uncertainty-adjusted Impact - Percentiles 10th	30th	50th	70th	90th
1	Off-Peak	0.71	0.71	0.00	-0.4%	67.9	0.00	0.00	0.00	0.00	0.00
2	Off-Peak	0.62	0.63	0.00	-0.4%	67.2	0.00	0.00	0.00	0.00	0.00
3	Off-Peak	0.57	0.57	0.00	-0.2%	66.6	0.00	0.00	0.00	0.00	0.00
4	Off-Peak	0.53	0.53	0.00	-0.1%	66.1	0.00	0.00	0.00	0.00	0.00
5	Off-Peak	0.52	0.52	0.00	-0.1%	65.6	0.00	0.00	0.00	0.00	0.00
6	Off-Peak	0.53	0.53	0.00	-0.2%	65.2	0.00	0.00	0.00	0.00	0.00
7	Off-Peak	0.56	0.56	0.00	-0.3%	65.0	0.00	0.00	0.00	0.00	0.00
8	Off-Peak	0.58	0.58	0.00	0.1%	65.2	0.00	0.00	0.00	0.00	0.00
9	Off-Peak	0.57	0.57	0.00	-0.4%	66.8	0.00	0.00	0.00	0.00	0.00
10	Off-Peak	0.57	0.57	0.00	-0.7%	69.5	-0.01	-0.01	0.00	0.00	0.00
11	Off-Peak	0.59	0.59	0.00	-0.5%	72.5	-0.01	0.00	0.00	0.00	0.00
12	Off-Peak	0.64	0.65	0.00	-0.2%	75.5	-0.01	0.00	0.00	0.00	0.00
13	Off-Peak	0.73	0.73	0.00	0.1%	77.8	0.00	0.00	0.00	0.00	0.01
14	Off-Peak	0.84	0.84	0.00	0.2%	79.5	0.00	0.00	0.00	0.00	0.01
15	Off-Peak	0.96	0.95	0.01	0.6%	80.7	0.00	0.00	0.01	0.01	0.01
16	Off-Peak	1.09	1.08	0.01	0.8%	81.5	0.00	0.01	0.01	0.01	0.01
17	Peak	1.21	1.20	0.02	1.4%	81.5	0.01	0.02	0.02	0.02	0.02
18	Peak	1.30	1.28	0.02	1.4%	80.7	0.02	0.02	0.02	0.02	0.02
19	Peak	1.31	1.29	0.02	1.5%	79.2	0.02	0.02	0.02	0.02	0.02
20	Peak	1.26	1.24	0.02	1.3%	76.8	0.01	0.02	0.02	0.02	0.02
21	Peak	1.22	1.21	0.01	1.0%	73.8	0.01	0.01	0.01	0.01	0.01
22	Off-Peak	1.14	1.14	0.00	0.3%	71.3	0.00	0.00	0.00	0.00	0.01
23	Off-Peak	1.00	1.00	0.00	-0.2%	69.8	0.00	0.00	0.00	0.00	0.00
24	Off-Peak	0.84	0.84	0.00	-0.4%	68.8	-0.01	0.00	0.00	0.00	0.00

5.1 Summary of Pilot Rates

Figures 2-1 and 2-2 in Section 2 summarized the rate periods and prices for Rates 4 and 5. Importantly, the prices shown in those figures and discussed below do not reflect the baseline credit of 8¢/kWh that applies to each rate.

Rate 4 has two rate periods on summer weekdays and three on winter weekdays. The peak and mid-peak period on Rate 4 is the same all year long and runs from 4 PM to 9 PM. The peak to off-peak price ratio (ignoring the baseline credit) is 1.8 to 1 in summer and mid-peak to super off-peak ratio is 1.7 to 1 in winter. Customers on SCE's Rate 4 pay super off-peak prices on weekdays and weekends in the winter. In summer, off-peak prices are in effect on weekends from 9 PM to 4 PM, which is the time-period covered by the combination of off-peak and super off-peak prices during winter.

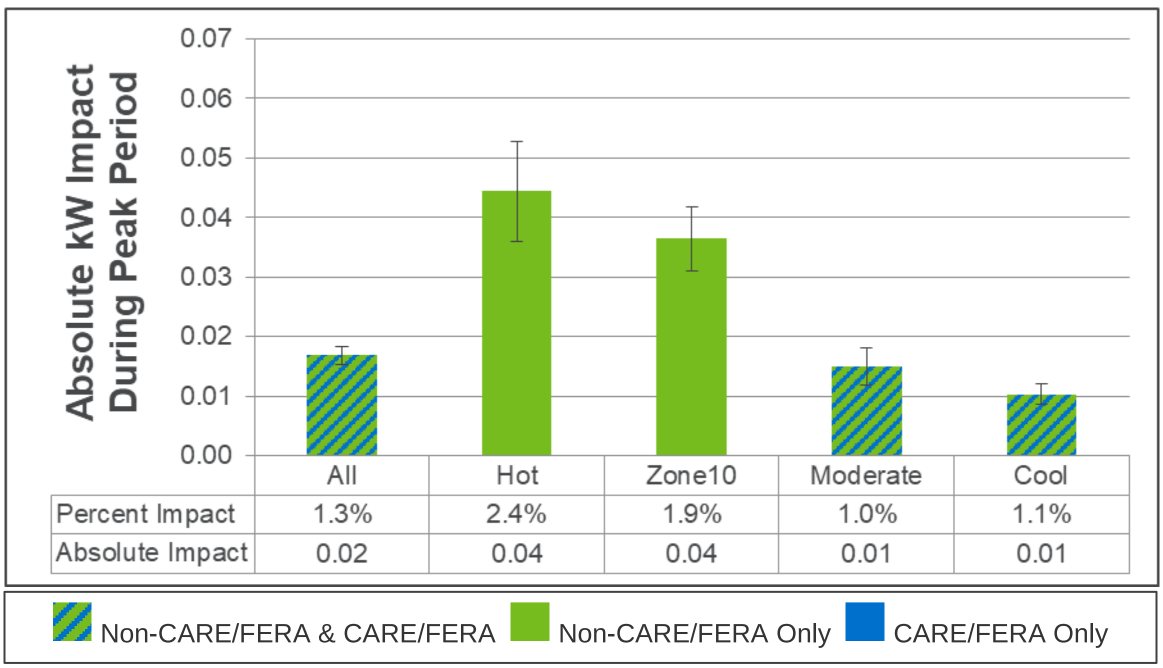
SCE's Rate 5 has two rate periods on summer weekdays and three on winter weekdays, the same structure as Rate 4. Compared with Rate 4, Rate 5 has a much shorter peak period but a slightly higher peak price in summer months (51¢/kWh for Rate 5 versus 42¢/kWh for Rate 4) and slightly high mid-peak price in winter months (32¢/kWh for Rate 5 versus 30¢/kWh for Rate 4). The peak period runs from 5 PM to 8 PM. Rate 5 also features a super off-peak price of roughly 18¢/kWh between 8 AM and 5 PM on weekdays and weekends during winter. The ratio of peak to off-peak prices in the summer is roughly 2.1 to 1. In winter, the mid-peak to super off-peak price ratio is roughly 1.8 to 1. On weekends, customers pay the off-peak price between 8 PM and 8 AM and the super off-peak price during the same overnight hours as on weekdays, from 8 AM to 5 PM. For the two rates, the summer season covers the months of June through September. The winter season is October through May.

5.2 Rate 4

5.2.1 Load Impacts by Pilot Segment

Figure 5-2 shows the average peak period load reduction in absolute terms for Rate 4 for SCE's service territory as a whole and for each climate region. The lines bisecting the top of each bar in the figure show the 90% confidence band for each estimate. If the confidence band includes 0, it means that the estimated load impact is not statistically different from 0 at the 90% level of confidence. If the confidence bands for two bars do not overlap, it means that the observed difference in the load impacts is statistically significant. If they do overlap, it does not necessarily mean that the difference is not statistically significant.[1] In these cases, t-tests were calculated to determine whether the difference is statistically significant.[2] Bars with blue and green stripes indicate that the segment includes a combination of CARE/FERA customers and non-CARE/FERA customers, while solid green bars represent segments that are non-CARE/FERA only. Solid blue bars represent segments that are CARE/FERA customers only. However, it is important to note that the "All" category includes non-CARE/FERA customers from all climate regions but CARE/FERA customers only from the moderate and cool climate regions. As a result, the "All" estimates cannot be directly compared to the "Moderate" and "Cool" estimates.

Figure 5-2: Average Peak Period Load Impacts for SCE Rate 4 by Climate Region (Positive values represent load reductions)



	All	Hot	Zone10	Moderate	Cool
Percent Impact	1.3%	2.4%	1.9%	1.0%	1.1%
Absolute Impact	0.02	0.04	0.04	0.01	0.01

As seen in Figure 5-2, the average peak-period load impact for the service territory as a whole and for each climate region is statistically significant at the 90% level of confidence. On average, default pilot participants across SCE's service territory on Rate 4 reduced peak-period electricity use by 1.3%, or 0.02 kW, across the five-hour peak period from 4 PM to 9 PM.

[1] For further discussion of this topic, see https://www.cscu.cornell.edu/news/statnews/stnews73.pdf.

[2] The test was applied at the 90% confidence level which means that a t-value exceeding 1.65 indicates statistical significance.

Keeping in mind that differences across regions reflect both differences in climate and the presence or absence of CARE/FERA customers, the average peak-period load reduction ranges from a high of 2.4% and 0.04 kW in the hot climate region to a low of about 1.0% and 0.01 kW in the moderate climate region. The difference in load impacts between the moderate and cool climate regions is small but statistically significant in absolute terms (but not in percentage terms) while the difference in impacts in Climate Zone 10 and the hot region are not statistically significant.

Table 5-1 shows the average percent and absolute hourly load impacts for each period for weekdays, weekends, and for the average monthly system peak day for the SCE service territory as a whole and for the participant population in each climate region. The percent reduction equals the load impact in absolute terms (kW) divided by the reference load. Shaded cells in the table contain load impact estimates that are not statistically significant at the 90% confidence level. The percentage and absolute values in the first row of Table 5-1, which represent the load impacts in the peak period on the average weekday, equal the values shown in Figure 5-2, discussed above.

The reference loads shown in Table 5-1 represent estimates of what customers on the TOU rate would have used if they had not responded to the price signals contained in the TOU tariff. As seen in the table, average hourly usage during the peak period is roughly 1.26 kW for the service territory as a whole, and around 0.83 kW over the 24 hour average weekday. In the hot climate region and Climate Zone 10, average usage in the peak period is greater at 1.88 kW. Average usage in the moderate climate region is 1.45 kW and in the cool region it is 0.96 kW, which is roughly half what it is in the hot region. However, the cool climate region includes CARE/FERA customers while the hot climate region does not.

The monthly system peak day estimates represent the average across the four weekdays, one in each summer month, when SCE's system peaked in 2019. Peak period reference loads are higher on these days than on the average weekday. For the service territory as a whole, the percent reduction in monthly system peak day peak period loads (1.0%) is slightly lower than the load reduction on the average weekday (1.3%); however, the absolute load reduction is the same as on the average weekday (0.02 kW). Customers had small but statistically significant daily usage decreases on the average weekend even though off-peak prices were in effect for the majority of weekend hours and mid-peak prices were in effect for the remaining hours.

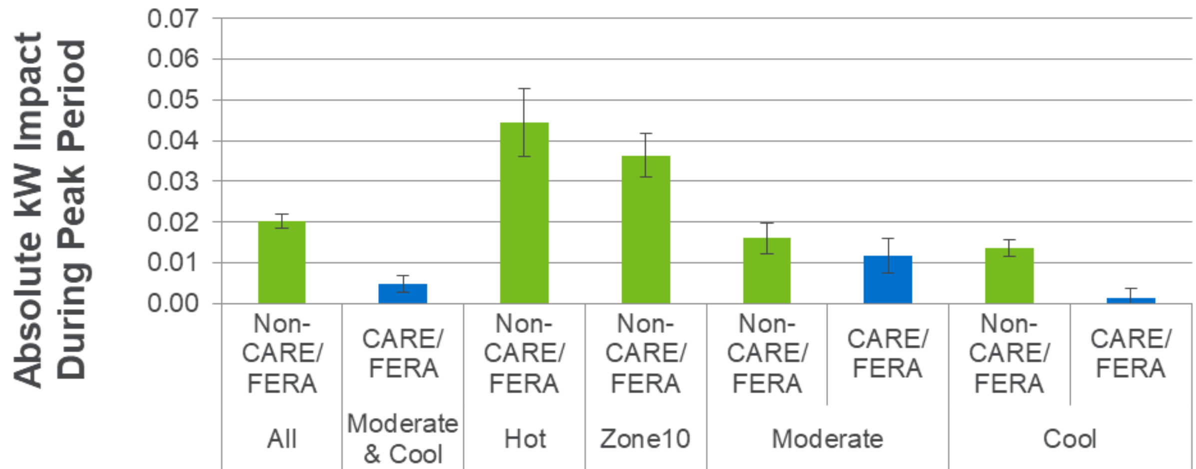
Table 5-1: Average Hourly Load Impacts by Climate Region Rate Period and Day Type for SCE Rate 4 (Positive values represent load reductions, negative values represent load increases)

Rate 4																		
Day Type	Period	Hours	All			Hot			Zone10			Moderate			Cool			
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	
Average Weekday	Peak	4 PM to 9 PM	1.26	0.02	1.3%	1.88	0.04	2.4%	1.88	0.04	1.9%	1.45	0.01	1.0%	0.96	0.01	1.1%	
	Off-Peak	9 PM to 4 PM	0.71	0.00	0.0%	0.98	0.02	1.7%	0.94	0.00	0.1%	0.78	0.00	-0.5%	0.61	0.00	-0.2%	
	Day	All Hours	0.83	0.00	0.4%	1.17	0.02	1.9%	1.13	0.01	0.8%	0.92	0.00	0.0%	0.68	0.00	0.2%	
Average Weekend	Mid-Peak	4 PM to 9 PM	1.27	0.02	1.3%	1.86	0.04	1.9%	1.90	0.04	1.9%	1.46	0.01	1.0%	0.97	0.01	1.1%	
	Off-Peak	9 PM to 4 PM	0.74	0.00	0.1%	1.00	0.02	1.7%	0.99	0.00	0.4%	0.81	0.00	-0.4%	0.63	0.00	-0.1%	
	Day	All Hours	0.85	0.00	0.4%	1.18	0.02	1.7%	1.18	0.01	0.9%	0.94	0.00	0.1%	0.70	0.00	0.2%	
Monthly System Peak	Peak	4 PM to 9 PM	1.76	0.02	1.0%	2.28	0.04	1.8%	2.71	0.04	1.5%	2.15	0.02	0.9%	1.29	0.01	0.8%	
	Off-Peak	9 PM to 4 PM	0.97	0.00	0.0%	1.21	0.03	2.1%	1.41	0.00	0.0%	1.12	0.00	-0.3%	0.77	0.00	-0.2%	
	Day	All Hours	1.13	0.00	0.4%	1.44	0.03	2.0%	1.68	0.01	0.5%	1.33	0.00	0.1%	0.88	0.00	0.1%	

* A shaded cell indicates estimate is not statistically significant

Figure 5-3 shows the absolute peak period load impacts for Rate 4 for CARE/FERA and non-CARE/FERA customers for the service territory as a whole and for each climate region. Non-CARE/FERA segments are shaded with green while CARE/FERA segments are shaded in blue. In the cool climate region, both the percent and absolute load impacts in the peak period differ by a statistically significant amount and impacts are smaller for CARE/FERA customers than for non-CARE/FERA customers. In the moderate climate region, non-CARE/FERA customers produced larger absolute load reductions compared to CARE/FERA customers, but there is no statistically significant difference in the percentage or absolute impacts between the two customer segments. There is a statistically significant difference in load impacts between CARE/FERA and non-CARE/FERA customers at the service territory level but this comparison reflects both potential differences in behavior across the two segments as well as the fact that the non-CARE/FERA estimate includes customers in the hotter climate regions where absolute load impacts are typically larger. As such, this is not a valid comparison if the objective is to reflect only behavioral differences between the two customer segments.

Figure 5-3: Average Peak Period Impacts for SCE Rate 4 by Climate Region & CARE/FERA Status (Positive values represent load reductions)



	All	Moderate & Cool	Hot	Zone10	Moderate		Cool	
	Non-CARE/FERA	CARE/FERA	Non-CARE/FERA	Non-CARE/FERA	Non-CARE/FERA	CARE/FERA	Non-CARE/FERA	CARE/FERA
Percent Impact	1.5%	0.5%	2.4%	1.9%	1.0%	1.1%	1.3%	0.2%
Absolute Impact	0.02	0.00	0.04	0.04	0.02	0.01	0.01	0.00

Non-CARE/FERA & CARE/FERA   Non-CARE/FERA Only   CARE/FERA Only

Table 5-2 shows the estimated load impacts for each day type for the different rate period for the service territory as a whole and by climate region for non-CARE/FERA customers, and Table 5-3 shows the same segment values for CARE/FERA customers. For the service territory as a whole, non-CARE/FERA customers have average peak-period reference loads that are larger than CARE/FERA customers (1.36 kW for non-CARE/FERA and 0.88 kW for CARE/FERA), however the CARE/FERA segment only includes customers in the moderate and cool climate regions. Non-CARE/FERA customers have larger average usage rates across all climate regions and for daily electricity usage on average summer weekdays, weekends, and on monthly system peak days.

For the majority of customer segments and climate regions, there was a small but statistically significant reduction in daily electricity consumption. Put differently, the observed reduction in peak-period energy use was not completely offset by load shifting to non-peak time periods. In fact, non-CARE/FERA customers in the hot climate region showed a small reduction in usage in the off-peak period rather than an increase which would be observed if the amount of load shifting was significant. CARE/FERA customers in the moderate climate region decreased average daily usage on weekdays by 0.7%, whereas non-CARE/FERA customers in the same region did not have statistically significant daily kWh impacts. On monthly system peak days, non-CARE/FERA customers reduced daily electricity use by 0.5% and CARE/FERA did not decrease their overall usage by a statistically significant amount.

Table 5-2: Average Hourly Load Impacts by Rate Period and Day Type for SCE Rate 4 by Climate Region -- Non-CARE/FERA Customers (Positive values represent load reductions, negative values represent load increases)

Rate 4																	
Day Type	Period	Hours	All - Non-CARE/FERA			Hot - Non-CARE/FERA			Zone10 - Non-CARE/FERA			Moderate - Non-CARE/FERA			Cool - Non-CARE/FERA		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	1.36	0.02	1.5%	1.88	0.04	2.4%	1.88	0.04	1.9%	1.57	0.02	1.0%	1.03	0.01	1.3%
	Off-Peak	9 PM to 4 PM	0.76	0.00	0.0%	0.98	0.02	1.7%	0.94	0.00	0.1%	0.83	-0.01	-0.8%	0.64	0.00	-0.2%
	Day	All Hours	0.88	0.00	0.5%	1.17	0.02	1.9%	1.13	0.01	0.8%	0.98	0.00	-0.2%	0.72	0.00	0.3%
Average Weekend	Mid-Peak	4 PM to 9 PM	1.37	0.02	1.4%	1.86	0.04	1.9%	1.90	0.04	1.9%	1.59	0.01	0.9%	1.04	0.01	1.3%
	Off-Peak	9 PM to 4 PM	0.79	0.00	0.1%	1.00	0.02	1.7%	0.99	0.00	0.4%	0.86	-0.01	-0.6%	0.67	0.00	-0.1%
	Day	All Hours	0.91	0.00	0.5%	1.18	0.02	1.7%	1.18	0.01	0.9%	1.01	0.00	-0.2%	0.74	0.00	0.3%
Monthly System Peak	Peak	4 PM to 9 PM	1.90	0.02	1.2%	2.28	0.04	1.8%	2.71	0.04	1.5%	2.36	0.02	1.0%	1.39	0.01	1.0%
	Off-Peak	9 PM to 4 PM	1.04	0.00	0.1%	1.21	0.03	2.1%	1.41	0.00	0.0%	1.20	0.00	-0.3%	0.82	0.00	-0.2%
	Day	All Hours	1.22	0.01	0.5%	1.44	0.03	2.0%	1.68	0.01	0.5%	1.44	0.00	0.1%	0.94	0.00	0.2%

* A shaded cell indicates estimate is not statistically significant

Table 5-3: Average Hourly Load Impacts by Rate Period and Day Type for SCE Rate 4 by Climate Region -- CARE/FERA Customers (Positive values represent load reductions, negative values represent load increases)

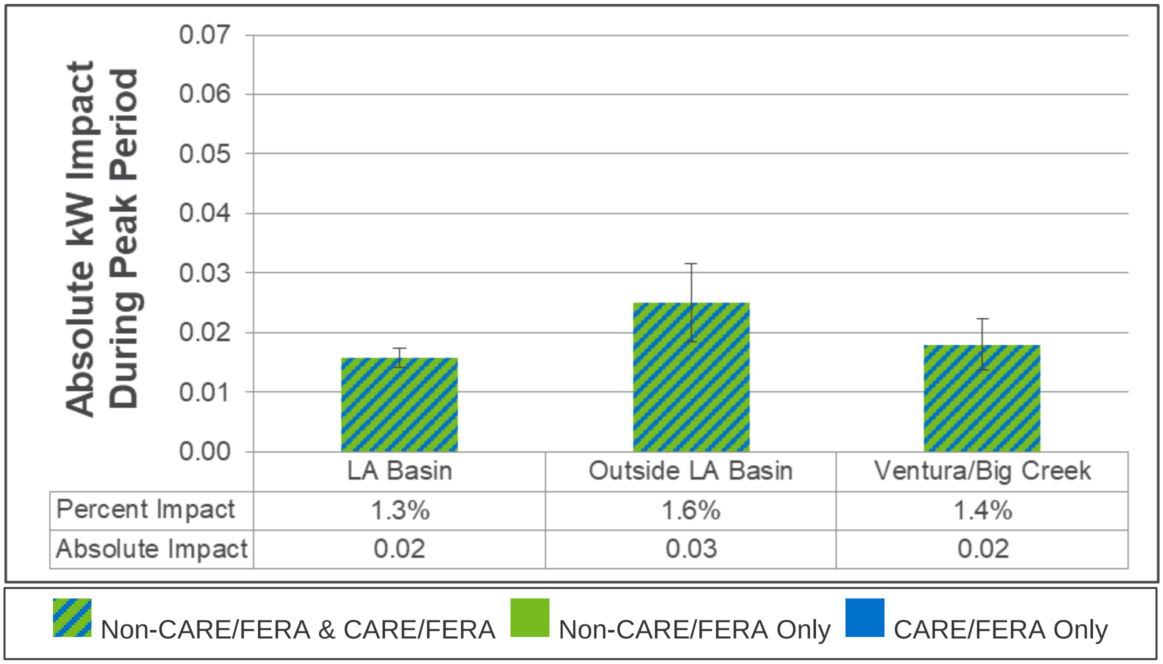
Rate 4																	
Day Type	Period	Hours	Moderate & Cool - CARE/FERA			Hot - CARE/FERA			Zone10 - CARE/FERA			Moderate - CARE/FERA			Cool - CARE/FERA		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	0.88	0.00	0.5%	N/A	N/A	N/A	N/A	N/A	N/A	1.11	0.01	1.1%	0.76	0.00	0.2%
	Off-Peak	9 PM to 4 PM	0.55	0.00	0.1%	N/A	N/A	N/A	N/A	N/A	N/A	0.64	0.00	0.5%	0.51	0.00	-0.2%
	Day	All Hours	0.62	0.00	0.2%	N/A	N/A	N/A	N/A	N/A	N/A	0.74	0.01	0.7%	0.56	0.00	-0.1%
Average Weekend	Mid-Peak	4 PM to 9 PM	0.87	0.01	0.8%	N/A	N/A	N/A	N/A	N/A	N/A	1.11	0.02	1.4%	0.75	0.00	0.3%
	Off-Peak	9 PM to 4 PM	0.58	0.00	0.2%	N/A	N/A	N/A	N/A	N/A	N/A	0.66	0.00	0.6%	0.53	0.00	-0.1%
	Day	All Hours	0.64	0.00	0.3%	N/A	N/A	N/A	N/A	N/A	N/A	0.76	0.01	0.9%	0.58	0.00	0.0%
Monthly System Peak	Peak	4 PM to 9 PM	1.19	0.00	0.4%	N/A	N/A	N/A	N/A	N/A	N/A	1.60	0.01	0.5%	0.97	0.00	0.3%
	Off-Peak	9 PM to 4 PM	0.72	0.00	-0.2%	N/A	N/A	N/A	N/A	N/A	N/A	0.89	0.00	-0.3%	0.63	0.00	-0.1%
	Day	All Hours	0.82	0.00	0.0%	N/A	N/A	N/A	N/A	N/A	N/A	1.04	0.00	0.0%	0.70	0.00	0.0%

* A shaded cell indicates estimate is not statistically significant

5.2.2 Load Impacts by LCA

Load impacts across SCE's three LCAs have not been reported previously. Approximately 80% of the D-TOU population resides in the LA Basin LCA, followed by 6% and 14% in Outside LA Basin and Ventura/Big Creek, respectively. Figure 5-4 shows the absolute peak period load impacts for Rate 4 for each LCA. Peak period load impacts were largest in the Outside LA Basin LCA with impacts equal to 1.6% or 0.03 kW. However, the difference between Outside LA Basin and the Ventura/Big Creek LCA is not statistically significant. The LA Basin LCA had the smallest load impacts of 1.3% or 0.02 kW (but this the difference between LA Basin and Ventura/Big Creek is not statistically significant in absolute or percentage terms).

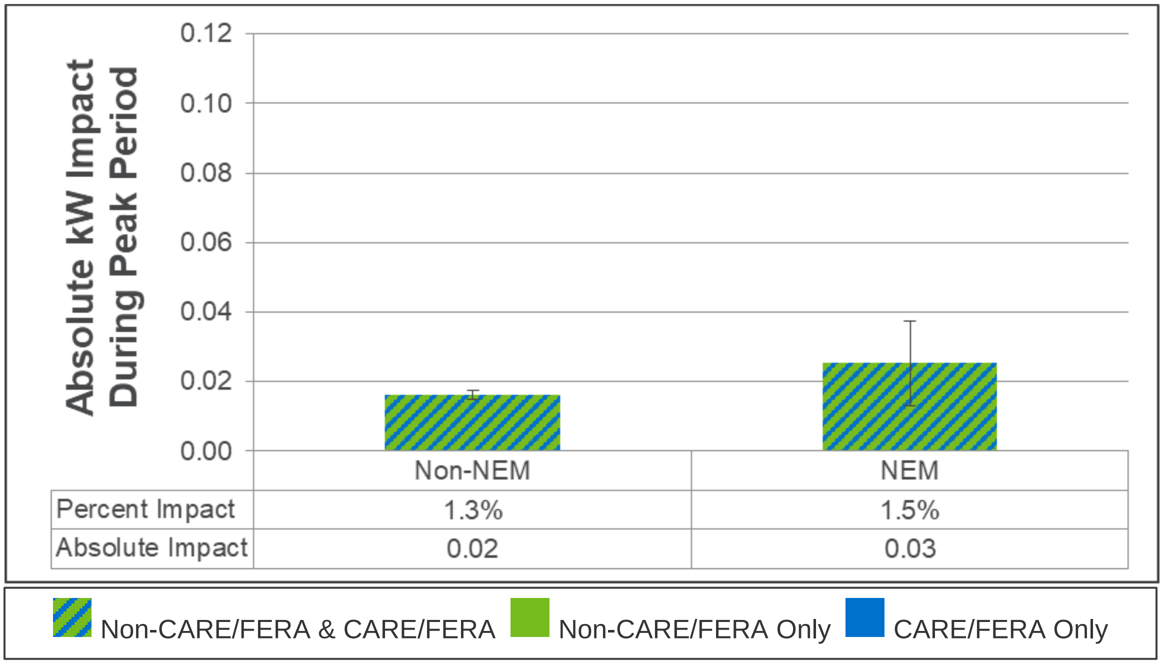
Figure 5-4: Average Peak Period Load Impacts for SCE Rate 4 by LCA (Positive values represent load reductions)



5.2.3 Load Impacts by NEM and Non-NEM

Figure 5-5 presents average summer weekday peak period load reductions for net metered (NEM) and non-net metered (non-NEM) customers. In this analysis, Non-NEM customers are defined to be customers who never became net metered throughout the course of the pilot (from launch through September 2019). NEM customers are those who were net metered at least one year prior to the launch of the pilot. Customers who became net metered during the pilot are excluded from the analysis presented here, but were included in the other ex post load impact estimates. Load impacts between non-NEM and NEM customers on Rate 4 were similar in percentage terms (1.3% and 1.5%, respectively). The difference between the two groups is not statistically significant in percentage or absolute terms.

Figure 5-5: Average Peak Period Load Impacts for SCE Rate 4 by NEM Status (Positive values represent load reductions)



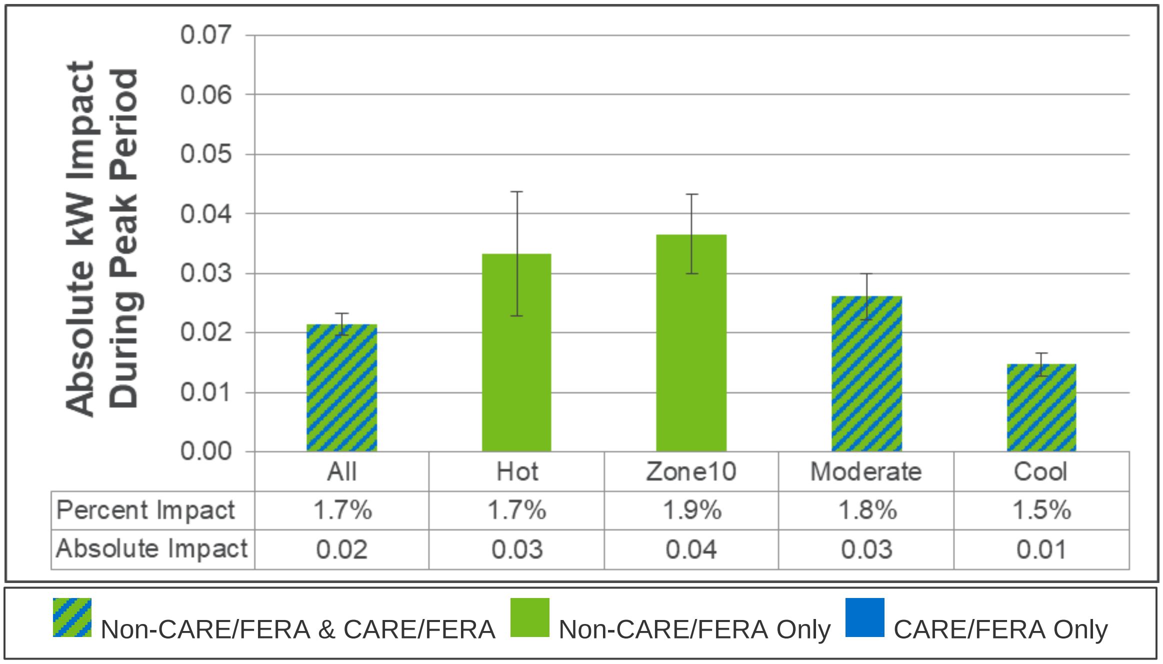
5.3 Rate 5

5.3.1 Load Impacts by Pilot Segment

SCE's Rate 5 has two rate periods on summer weekdays, and two rate periods on summer weekends, the same structure as Rate 4. Rate 5 peak period prices are higher than for Rate 4 but the peak period is only three hours, from 5 PM to 8 PM, whereas the Rate 4 peak period is five hours, from 4 PM to 9 PM. The Rate 5 peak price is 51¢/kWh for non-CARE/FERA customers and the off-peak price of 24¢/kWh on summer weekdays from hours 8 PM to 5 PM, which is one cent greater than the off-peak price for Rate 4.

Figure 5-6 shows the peak period load reductions on average weekdays for Rate 5. All load reductions are statistically significant at the 90% confidence level. The load reductions for the SCE territory as a whole, 1.7% or 0.02 kW are larger than those for Rate 4 (1.3% or 0.02 kW). Load impacts were greatest in the Climate Zone 10 region (1.9% or 0.04 kW) although there is no statistically significant difference in absolute load impacts between the hot region and Climate Zone 10. On the other hand, the difference in the absolute load impacts for all customers in the moderate and cool regions is statistically significant in absolute terms (but not in percentage terms). Indeed, the absolute load reduction in the moderate region is three times as large as in the cool region, although the difference in the percentage impacts is not as great.

Figure 5-6: Average Peak Period Load Impacts for SCE Rate 5 by Climate Region (Positive values represent load reductions)



	All	Hot	Zone10	Moderate	Cool
Percent Impact	1.7%	1.7%	1.9%	1.8%	1.5%
Absolute Impact	0.02	0.03	0.04	0.03	0.01

Table 5-4 presents estimates of load impacts for all relevant rate periods and day types for Rate 5 at the aggregate and climate region level. Average reference load usage was 1.29 kW at the full pilot level during the peak time on an average weekday. The highest demand estimates were observed in Climate Zone 10 on monthly system peak days during the peak period with a reference load of 2.74 kW.

The Climate Zone 10 and moderate climate regions had largest percentage reductions for average weekday (1.9% and 1.8%) respectively (but the Climate Zone 10 segment does not include CARE/FERA customers). The cool climate region had the lowest load impacts and average usage during the peak for average weekdays, average weekends, and monthly system peak days. The average reduction in daily electricity use was statistically significant overall and in each climate region for every day type.

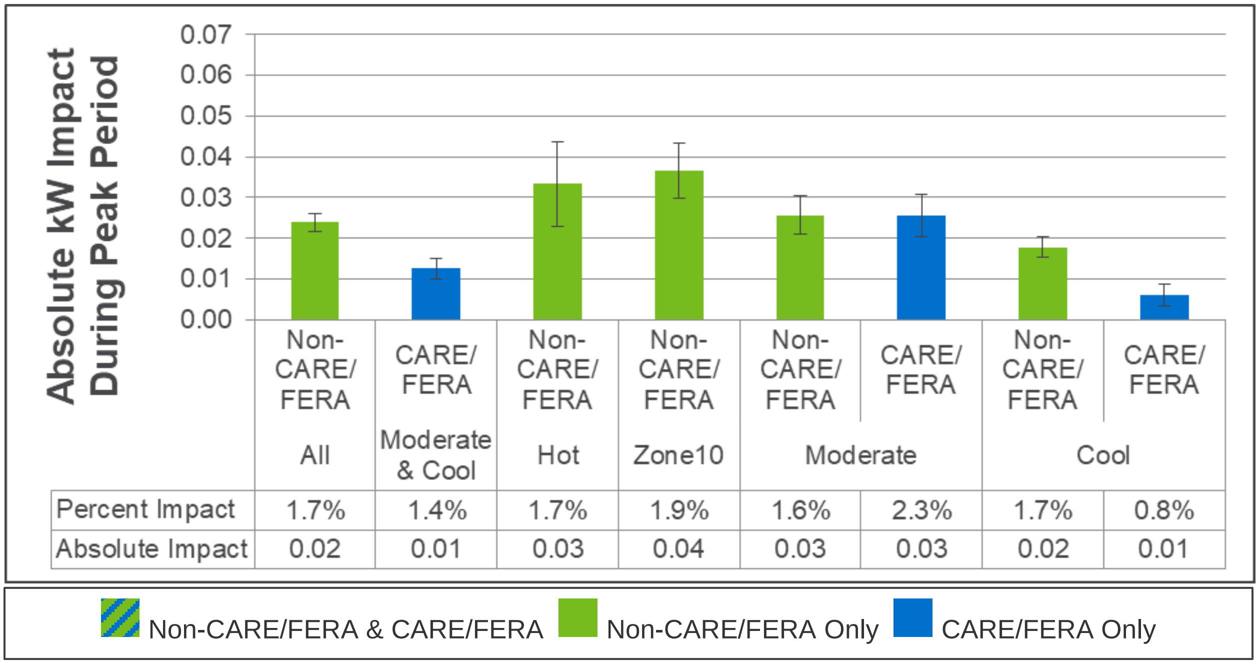
Table 5-4: Average Hourly Load Impacts by Climate Region, Rate Period and Day Type for SCE Rate 5
(Positive values represent load reductions, negative values represent load increases)

Rate 5																		
Day Type	Period	Hours	All			Hot			Zone10			Moderate			Cool			
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	5 PM to 8 PM	1.29	0.02	1.7%	1.95	0.03	1.7%	1.94	0.04	1.9%	1.49	0.03	1.8%	0.98	0.01	1.5%
	Off-Peak	8 PM to 5 PM	0.76	0.00	0.2%	1.05	0.01	1.3%	1.02	0.01	0.6%	0.84	0.00	0.2%	0.64	0.00	0.0%
	Day	All Hours	0.83	0.00	0.5%	1.17	0.02	1.4%	1.13	0.01	0.9%	0.92	0.00	0.5%	0.68	0.00	0.2%
Average Weekend	Mid-Peak	5 PM to 8 PM	1.29	0.02	1.3%	1.92	0.03	1.5%	1.95	0.04	1.9%	1.49	0.02	1.3%	0.97	0.01	1.1%
	Off-Peak	8 PM to 5 PM	0.79	0.00	0.3%	1.07	0.01	0.7%	1.06	0.01	0.6%	0.87	0.00	0.2%	0.66	0.00	0.0%
	Day	All Hours	0.85	0.00	0.5%	1.18	0.01	0.9%	1.18	0.01	0.9%	0.94	0.00	0.5%	0.70	0.00	0.2%
Monthly System Peak Day	Peak	5 PM to 8 PM	1.78	0.03	1.7%	2.34	0.03	1.1%	2.74	0.05	1.6%	2.19	0.04	1.9%	1.30	0.02	1.6%
	Off-Peak	8 PM to 5 PM	1.04	0.00	0.3%	1.31	0.01	1.1%	1.53	0.01	0.8%	1.21	0.00	0.1%	0.82	0.00	0.0%
	Day	All Hours	1.13	0.01	0.5%	1.44	0.02	1.1%	1.68	0.02	0.9%	1.33	0.01	0.5%	0.88	0.00	0.3%

* A shaded cell indicates estimate is not statistically significant

Figure 5-7 shows the peak period load reductions on weekdays for non-CARE/FERA and CARE/FERA customers. As noted with Rate 4, there are no CARE/FERA customers in the hot or Climate Zone 10 regions. In the cool climate region, non-CARE/FERA load reductions are larger than CARE/FERA load reductions in both absolute and percentage terms. This difference is statistically significant in absolute and percentage terms. In the moderate climate region, however, the difference in percentage terms is statistically significant, but the difference in absolute terms is not.

Figure 5-7: Average Peak Period Impacts for SCE Rate 5 by Climate Region & CARE/FERA Status (Positive values represent load reductions)



	All	Moderate & Cool	Hot	Zone10	Moderate		Cool	
	Non-CARE/FERA	CARE/FERA	Non-CARE/FERA	Non-CARE/FERA	Non-CARE/FERA	CARE/FERA	Non-CARE/FERA	CARE/FERA
Percent Impact	1.7%	1.4%	1.7%	1.9%	1.6%	2.3%	1.7%	0.8%
Absolute Impact	0.02	0.01	0.03	0.04	0.03	0.03	0.02	0.01

Table 5-5 and Table 5-6 show the load impacts for each rate period and day type for Rate 5 at the aggregate level and across climate regions. Non-CARE/FERA customers had higher average load and load reductions during peak times in the cool climate region on average weekdays, weekends and monthly system peak days. An interesting finding is that the load impacts on all off-peak periods were greater for the CARE/FERA group than the non-CARE/FERA group in the cool and moderate climate regions and the different day types. No values are reported for the hot and Climate Zone 10 regions for CARE/FERA customers as the pilot didn't include these populations.

Non-CARE/FERA customers had statistically significant reductions in average daily demand across most day types in each climate region except the moderate climate region. The greatest percent daily reductions occurred in the moderate climate region among CARE/FERA customers. On the average weekday, these customers reduced their average demand by 1.7%.

Table 5-5: Average Hourly Load Impacts by Rate Period and Day Type for SCE Rate 5 by Climate Region -- Non-CARE/FERA Customers (Positive values represent load reductions, negative values represent load increases)

Rate 5																	
Day Type	Period	Hours	All - Non-CARE/FERA			Hot - Non-CARE/FERA			Zone10 - Non-CARE/FERA			Moderate - Non-CARE/FERA			Cool - Non-CARE/FERA		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	5 PM to 8 PM	1.39	0.02	1.7%	1.95	0.03	1.7%	1.94	0.04	1.9%	1.62	0.03	1.6%	1.04	0.02	1.7%
	Off-Peak	8 PM to 5 PM	0.81	0.00	0.2%	1.05	0.01	1.3%	1.02	0.01	0.6%	0.89	0.00	-0.3%	0.67	0.00	-0.1%
	Day	All Hours	0.88	0.00	0.5%	1.17	0.02	1.4%	1.13	0.01	0.9%	0.98	0.00	0.1%	0.72	0.00	0.2%
Average Weekend	Mid-Peak	5 PM to 8 PM	1.40	0.02	1.3%	1.92	0.03	1.5%	1.95	0.04	1.9%	1.62	0.02	1.1%	1.05	0.01	1.2%
	Off-Peak	8 PM to 5 PM	0.84	0.00	0.2%	1.07	0.01	0.7%	1.06	0.01	0.6%	0.93	0.00	-0.2%	0.70	0.00	0.0%
	Day	All Hours	0.91	0.00	0.4%	1.18	0.01	0.9%	1.18	0.01	0.9%	1.01	0.00	0.1%	0.74	0.00	0.2%
Monthly System Peak Day	Peak	5 PM to 8 PM	1.93	0.03	1.7%	2.34	0.03	1.1%	2.74	0.05	1.6%	2.40	0.05	2.0%	1.40	0.03	1.8%
	Off-Peak	8 PM to 5 PM	1.12	0.00	0.2%	1.31	0.01	1.1%	1.53	0.01	0.8%	1.31	0.00	-0.2%	0.87	0.00	-0.1%
	Day	All Hours	1.22	0.01	0.5%	1.44	0.02	1.1%	1.68	0.02	0.9%	1.44	0.00	0.2%	0.94	0.00	0.3%

* A shaded cell indicates estimate is not statistically significant

Table 5-6: Average Hourly Load Impacts by Rate Period and Day Type for SCE Rate 5 by Climate Region -- CARE/FERA Customers (Positive values represent load reductions, negative values represent load increases)

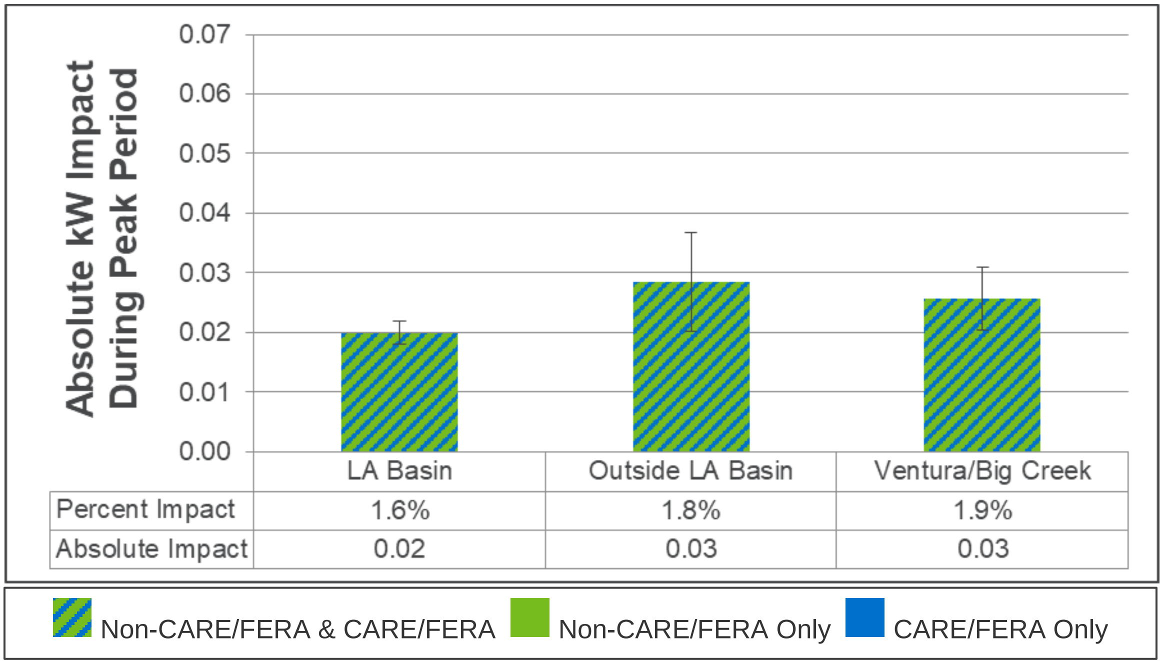
Rate 5																	
Day Type	Period	Hours	Moderate & Cool - CARE/FERA			Hot - CARE/FERA			Zone10 - CARE/FERA			Moderate - CARE/FERA			Cool - CARE/FERA		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	5 PM to 8 PM	0.89	0.01	1.4%	N/A	N/A	N/A	N/A	N/A	N/A	1.13	0.03	2.3%	0.76	0.01	0.8%
	Off-Peak	8 PM to 5 PM	0.58	0.00	0.7%	N/A	N/A	N/A	N/A	N/A	N/A	0.68	0.01	1.6%	0.53	0.00	0.2%
	Day	All Hours	0.62	0.01	0.9%	N/A	N/A	N/A	N/A	N/A	N/A	0.74	0.01	1.7%	0.56	0.00	0.3%
Average Weekend	Mid-Peak	5 PM to 8 PM	0.88	0.01	1.4%	N/A	N/A	N/A	N/A	N/A	N/A	1.12	0.03	2.4%	0.74	0.01	0.7%
	Off-Peak	8 PM to 5 PM	0.60	0.00	0.7%	N/A	N/A	N/A	N/A	N/A	N/A	0.70	0.01	1.5%	0.55	0.00	0.2%
	Day	All Hours	0.64	0.01	0.8%	N/A	N/A	N/A	N/A	N/A	N/A	0.76	0.01	1.7%	0.58	0.00	0.3%
Monthly System Peak Day	Peak	5 PM to 8 PM	1.20	0.01	1.2%	N/A	N/A	N/A	N/A	N/A	N/A	1.62	0.03	1.8%	0.97	0.01	0.9%
	Off-Peak	8 PM to 5 PM	0.76	0.01	0.8%	N/A	N/A	N/A	N/A	N/A	N/A	0.95	0.01	1.2%	0.66	0.00	0.6%
	Day	All Hours	0.82	0.01	0.8%	N/A	N/A	N/A	N/A	N/A	N/A	1.04	0.01	1.3%	0.70	0.00	0.6%

* A shaded cell indicates estimate is not statistically significant

5.3.2 Load Impacts by LCA

Figure 5-8 shows the absolute peak period load impacts for Rate 5 for each LCA. Peak period load impacts were largest in the Outside LA Basin LCA with impacts equal to 1.8% or 0.03 kW. However, the difference between Outside LA Basin and the Ventura/Big Creek LCA is not statistically significant in absolute or percentage terms. The difference between Outside LA Basin and LA Basin is statistically significant in absolute but not percentage terms.

Figure 5-8: Average Peak Period Load Impacts for SCE Rate 5 by LCA (Positive values represent load reductions)

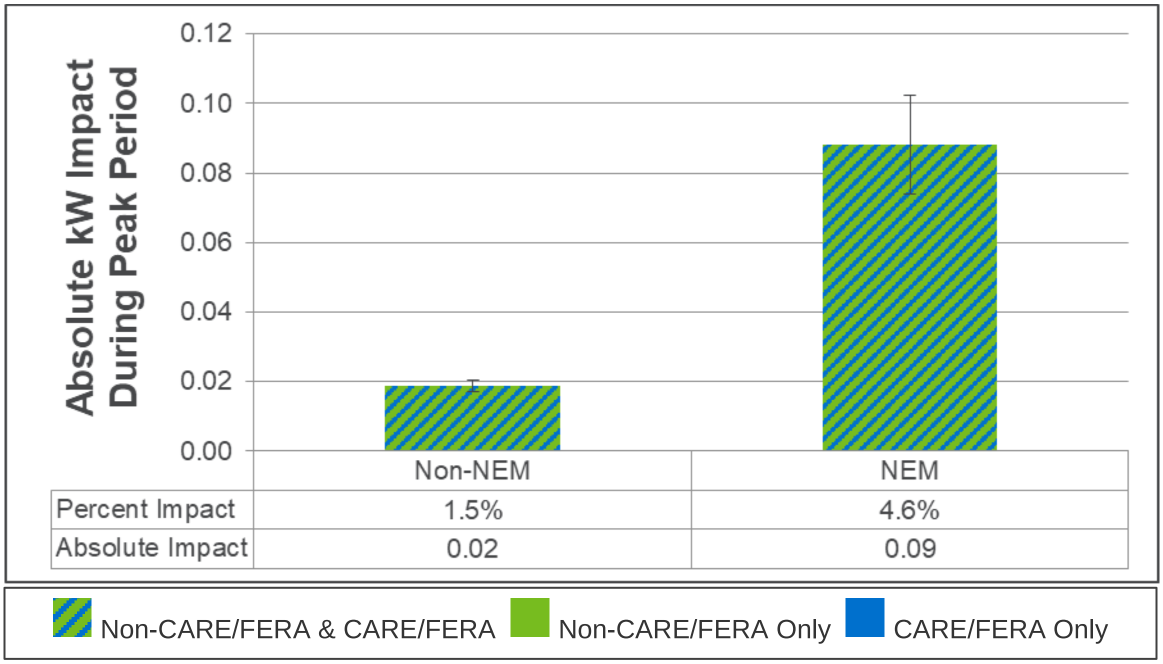


	LA Basin	Outside LA Basin	Ventura/Big Creek
Percent Impact	1.6%	1.8%	1.9%
Absolute Impact	0.02	0.03	0.03

5.3.3 Load Impacts by NEM and Non-NEM

Figure 5-9 presents average summer weekday peak period load reductions for non-NEM and NEM customers. Unlike Rate 4, there is a large difference in load impacts between the two populations. NEM customers on Rate 5 reduced demand by 4.6% or 0.09 kW, while non-NEM impacts were equal to 1.5% and 0.02. This difference is statistically significant in absolute and percentage terms.

Figure 5-9: Average Peak Period Load Impacts for SCE Rate 5 by NEM Status (Positive values represent load reductions)

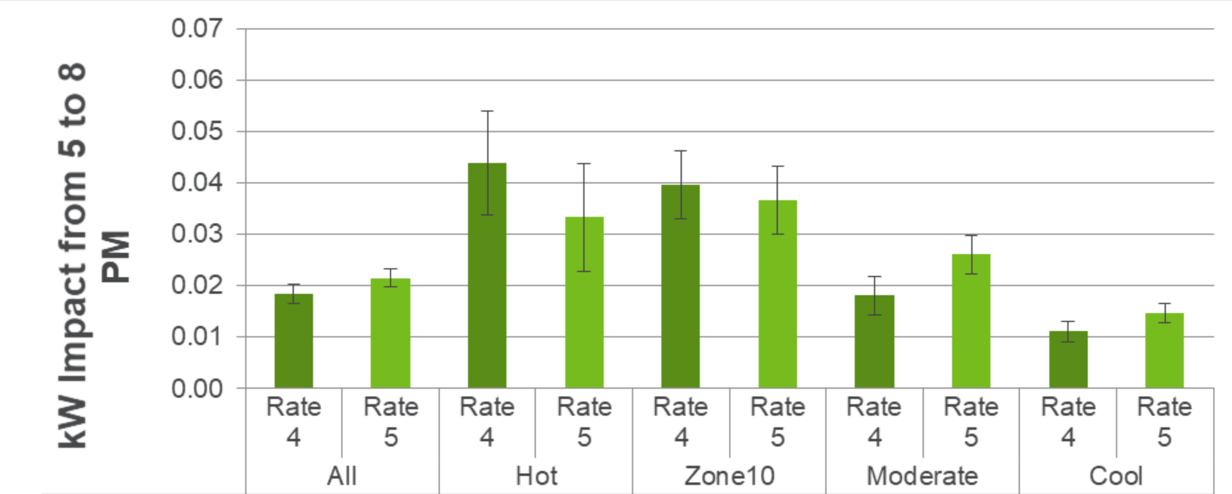


5.4 Comparison across Rates

Figure 5-10 compares the load impacts for the two rates tested by SCE for the common set of peak-period hours from 5 PM to 8 PM for the entire summer period from June through September 2019. Using a common set of hours reduces differences in impacts across rates that might be due to differences in the number of hours included in the peak period or the timing of those hours. The hours from 5 PM to 8 PM define the peak period for SCE's Rate 5. Rate 4 has a five hour peak period, from 4 PM to 9 PM and both tariffs have two rate periods in summer. The shorter duration of Rate 5 is offset by the higher peak price. Both Rate 4 and Rate 5 have the same baseline credit.

Customers on Rate 5, which had a shorter peak period with a higher peak period price, produced larger average load reductions than Rate 4 customers in the moderate and cool climate regions during the common hours from 5 PM to 8 PM, although not all differences were statistically significant. The largest difference was in the moderate climate region, where Rate 5 customers had percent load reductions that were 70% larger than those provided by Rate 4 customers (however the impacts were similar in terms of kW). This difference was statistically significant. The difference was also statistically significant in the pilot as a whole and in the cool climate region.

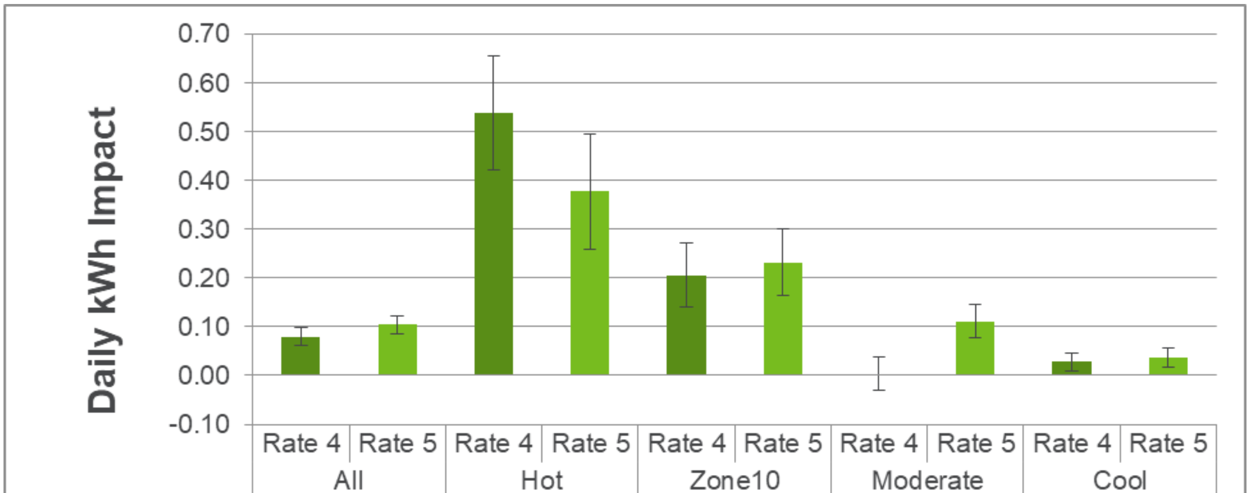
Figure 5-10: Average Impacts from 5 PM to 8 PM across Rates



	All		Hot		Zone10		Moderate		Cool	
	Rate 4	Rate 5	Rate 4	Rate 5	Rate 4	Rate 5	Rate 4	Rate 5	Rate 4	Rate 5
Percent Impact	1.4%	1.7%	2.3%	1.7%	2.0%	1.9%	1.2%	1.8%	1.1%	1.5%
Absolute Impact	0.02	0.02	0.04	0.03	0.04	0.04	0.02	0.03	0.01	0.01

Figure 5-11 presents the average daily kWh impacts for each rate during the summer 2019 period. Daily load reductions were very similar between the two rates with the exception of the hot and moderate climate regions. In the moderate climate region, customers on Rate 4 did not have statistically significant daily kWh impacts, while those on Rate 5 reduced their daily consumption by 0.5% or 0.11 kWh. This difference was statistically significant. In the hot climate region, Rate 4 had larger daily kWh reductions than Rate 5, but the difference was not statistically significant.

Figure 5-11: Average Daily kWh Impacts across Rates



	All		Hot		Zone10		Moderate		Cool	
	Rate 4	Rate 5	Rate 4	Rate 5	Rate 4	Rate 5	Rate 4	Rate 5	Rate 4	Rate 5
Percent Impact	0.4%	0.5%	1.9%	1.4%	0.8%	0.9%	0.0%	0.5%	0.2%	0.2%
Absolute Impact	0.08	0.10	0.54	0.38	0.21	0.23	0.00	0.11	0.03	0.04

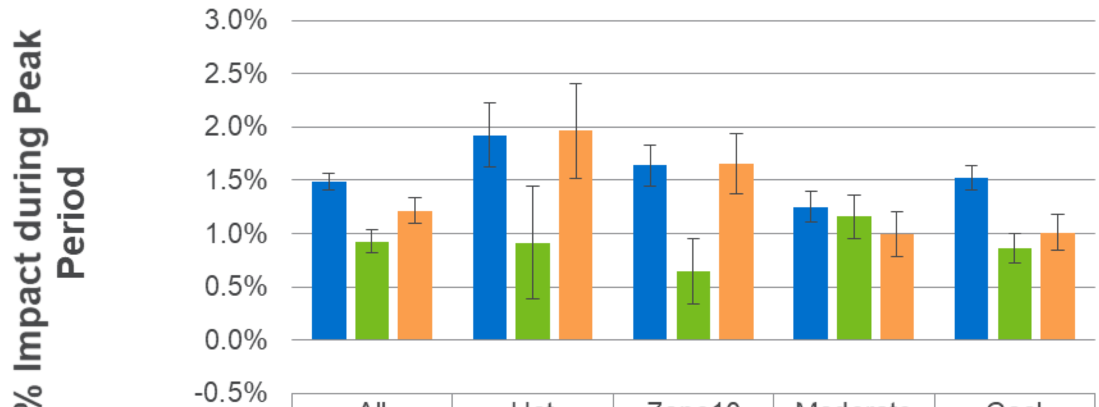
6 Persistence of Load Impacts

The impacts in this section represent customers who were active SCE customers until the end of September 2019, which includes two summer seasons and one winter season. Using this method, it is possible to compare impacts between seasons for a single group of customers, rather than a changing population. Customers who opted out of the pilot are included here to maintain the RED, and the methodology used here is identical to that used in the ex post impact analysis. While there is not a second winter for persistence comparison, the winter impacts for the subset of customers who were active SCE customers until September 2019 are included with the two summer impacts to illustrate the relative differences in impacts between the summer and winter seasons for a common set of customers.

6.1 Rate 4

Figure 6-1 presents the average percent impacts for the peak period for customers who remained active SCE customers through the second summer of the pilot (September 2019). All three seasons are presented for the territory as a whole and for each climate region. For the territory as a whole and for each climate region, load impacts were smaller in winter than in the summer seasons. One exception was the moderate climate region, in which summer 2019 impacts were smaller than winter 2018/2019 (however the difference was not statistically significant). Impacts decreased slightly for the territory as a whole between the first and second summer, at about 1.5% in 2018 and 1.2% in 2019. The difference was statistically significant in both absolute and percentage terms. Summer impacts increased for customers in the hot climate region and Climate Zone 10, but the differences were very small and not statistically significant. This part of the analysis does not take differences in weather into account between the two summers. Therefore, Section 6.3 will examine the differences between the two summers and show how they relate to weather.

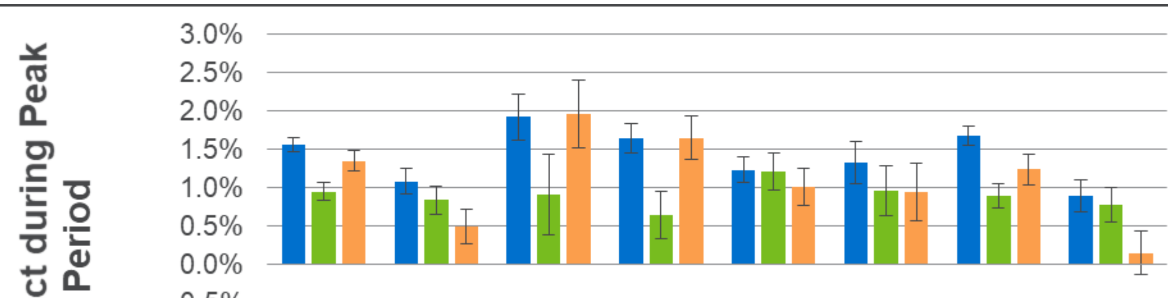
Figure 6-1: Percent Impacts for Peak Period for Rate 4, by Season (Positive values represent load reductions)



	All	Hot	Zone10	Moderate	Cool
Summer - 2018	1.5%	1.9%	1.6%	1.2%	1.5%
Winter - 2018/2019	0.9%	0.9%	0.6%	1.2%	0.9%
Summer - 2019	1.2%	2.0%	1.7%	1.0%	1.0%

Figure 6-2 presents average seasonal impacts for non-CARE/FERA and CARE/FERA customers on Rate 4. CARE/FERA customers decreased their percent impacts between the first and second summer, but these increases were not statistically significant in the moderate climate region.

Figure 6-2: Percent Impacts for Peak Period for Rate 4, by Season For CARE/FERA and Non-CARE/FERA Customers (Positive values represent load reductions)

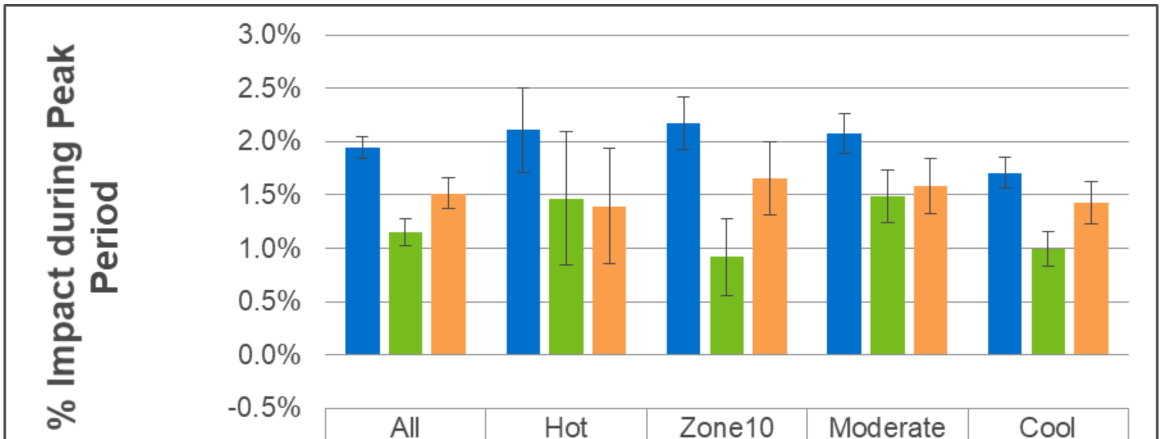


	All		Hot	Zone10	Moderate		Cool	
	Non-CARE/FERA	CARE/FERA	Non-CARE/FERA	Non-CARE/FERA	Non-CARE/FERA	CARE/FERA	Non-CARE/FERA	CARE/FERA
Summer - 2018	1.6%	1.1%	1.9%	1.6%	1.2%	1.3%	1.7%	0.9%
Winter - 2018/2019	1.0%	0.8%	0.9%	0.6%	1.2%	1.0%	0.9%	0.8%
Summer - 2019	1.3%	0.5%	2.0%	1.7%	1.0%	0.9%	1.2%	0.2%

6.2 Rate 5

Figure 6-3 presents seasonal load impacts for Rate 5 customers in SCE's territory as a whole and for each climate region. Recall that these load impacts only represent customers who remained active SCE participants through the end of the second summer of the pilot. For each climate zone and the SCE territory as a whole, impacts were greatest during the first summer (June through September 2018). The differences between the two summers were statistically significant in each climate region. Additionally, at the territory level, winter load impacts were smaller than those in both summers. This difference was statistically significant.

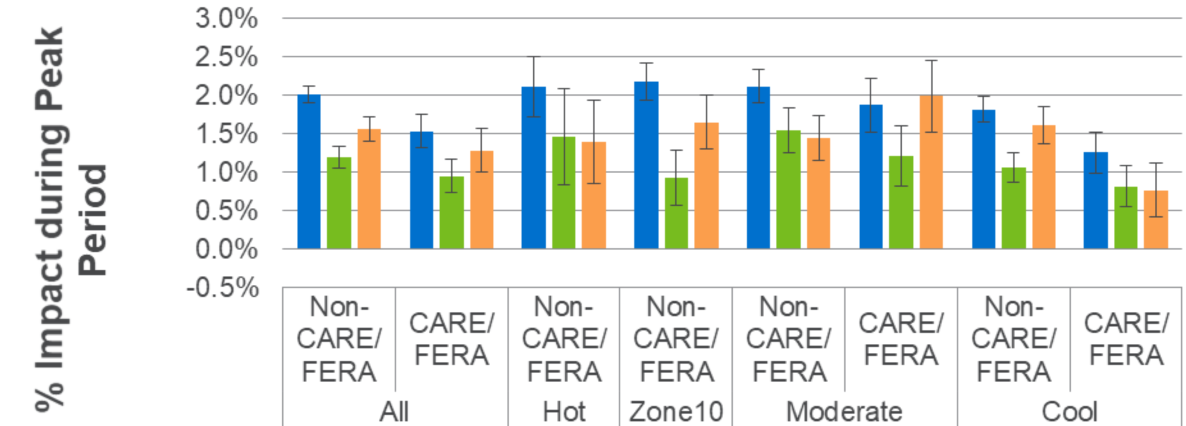
Figure 6-3: Percent Impacts for Peak Period for Rate 5, by Season (Positive values represent load reductions)



	All	Hot	Zone10	Moderate	Cool
Summer - 2018	1.9%	2.1%	2.2%	2.1%	1.7%
Winter - 2018/2019	1.2%	1.5%	0.9%	1.5%	1.0%
Summer - 2019	1.5%	1.4%	1.7%	1.6%	1.4%

Figure 6-4 presents average seasonal impacts for non-CARE/FERA and CARE/FERA customers on Rate 5. In the moderate climate region, CARE/FERA customers increased their percent impacts between the first and second summer, but these increases were not statistically significant. Both CARE/FERA and non-CARE/FERA customers in the cool climate region showed smaller impacts in the second summer compared with the first, but the differences were not statistically significant. Winter impacts were generally smaller than summer impacts.

Figure 6-4: Percent Impacts for Peak Period for Rate 5, by Season For CARE/FERA and Non-CARE/FERA Customers (Positive values represent load reductions)



	All		Hot	Zone10	Moderate		Cool	
	Non-CARE/FERA	CARE/FERA	Non-CARE/FERA	Non-CARE/FERA	Non-CARE/FERA	CARE/FERA	Non-CARE/FERA	CARE/FERA
Summer - 2018	2.0%	1.5%	2.1%	2.2%	2.1%	1.9%	1.8%	1.3%
Winter - 2018/2019	1.2%	1.0%	1.5%	0.9%	1.5%	1.2%	1.1%	0.8%
Summer - 2019	1.6%	1.3%	1.4%	1.7%	1.4%	2.0%	1.6%	0.8%

6.3 Comparison of 2018 and 2019 Weather

Several factors contribute to differences in load impacts from year to year, and a key driver is weather. Figure 6-5 presents Rate 4 average weekday peak period impacts and temperatures for the summer periods in 2018 and 2019. Figure 6-6 presents the same information for Rate 5. The following figures illustrate that on average, temperatures were slightly cooler in 2019 (more blue dots on the left with lower tempertaures and more green dots to the right with higher temperatures). It also shows that at similar temperatures, impacts in 2019 were slightly lower than impacts in 2018 (the blue trendline is below the green trendline). It may be possible that customers were slightly less responsive to the rates in the second summer.

Figure 6-5: Comparison of Summer Average Weekday Peak Period Temperatures and Impacts – Rate 4

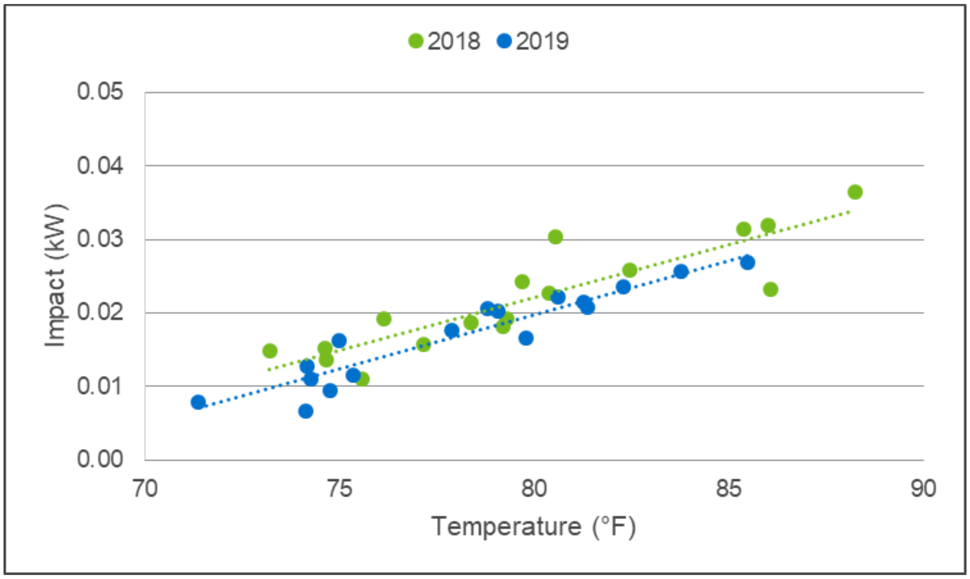
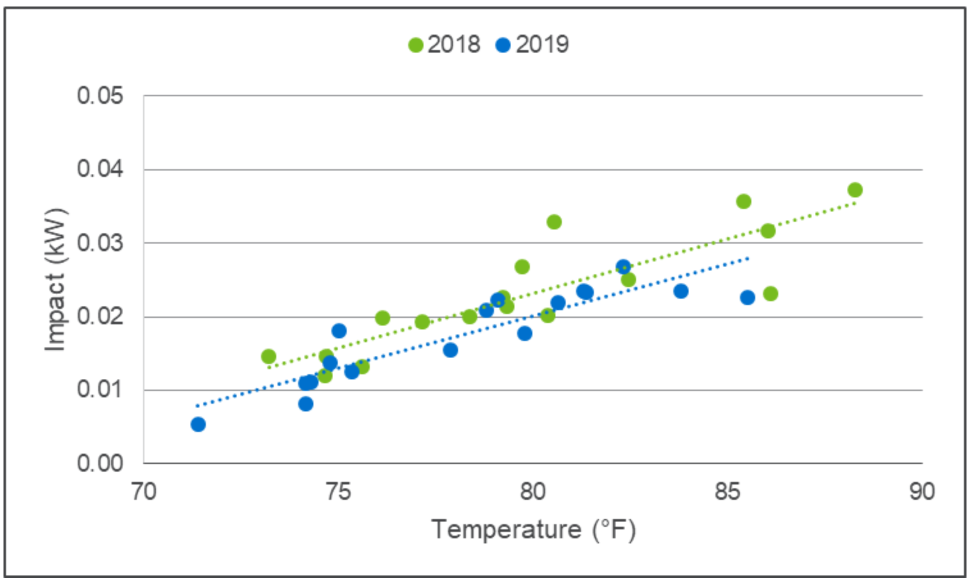


Figure 6-6: Comparison of Summer Average Weekday Peak Period Temperatures and Impacts – Rate 5



7 Ex Ante Load Impacts

Ex ante load impacts represent what customers on the default TOU rates can deliver under a standardized set of weather conditions given changes in enrollment over the forecast horizon. The weather used for ex ante load impact estimation is meant to reflect conditions on the average weekday under both normal (1-in-2 years) and extreme (1-in10 years) weather. The window used for ex ante estimation, the Resource Adequacy (RA) window, is the same as the Rate 4 peak period (4:00 to 9:00 PM). This period overlaps with the Rate 5 peak period (5:00 to 8:00 PM). The current RA window is in effect during all months of the year.

At a high level, ex ante impact estimates for Rate 4 and Rate 5 were developed using the following process:

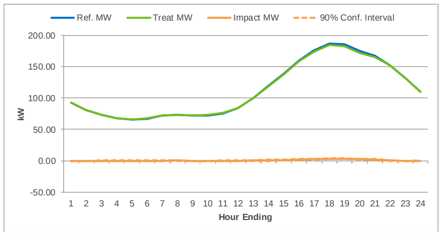
- First, ex post load impacts from October 2018 through September 2019 were developed using the fixed effects regression methodology described in Section 3.1;
- Next, the relationship between ex post load impacts and temperature is estimated for each hour of the day, each season (summer/winter) and each customer segment and rate;
- Then, ex ante weather conditions are used as input to the regression models to predict impacts for each hour for the average weekday and monthly system peak days from January through December.

A similar method was used to estimate reference loads, which are needed to meet this evaluation's reporting requirements. Underlying the values presented in this section are electronic tables that contain estimates for each hour of the day for each day type, segment, month, and forecast year from 2020 through 2030. These values are contained in Excel spreadsheets that are available upon request through the CPUC. Figure 7-1 shows an example of the content of these electronic tables for SCE Rate 4 for all eligible customers in the service territory. Pull down menus in the upper left hand corner allow users to select different customer segments, months, and forecast years.

Figure 7-1: Example of Content of Electronic Tables Underlying Load Impacts Summarized in this Report (SCE Rate 4, Average August 2020 Weekday, SCE 1-in-2 Weather)

Select Options Below	
Weather Data:	SCE
Weather Year:	1-in-2
Month:	August
Day Type:	Average Weekday
Result Type:	Aggregate
Forecast Year:	2020
Segment:	All
Rate:	Rate 4
Enrollment:	128,033

Period	Weighted Temp. (°F)	Ref. MW	Treat MW	Impact MW	90% Conf. Interval		% Impact
Peak	79.4	178.26	175.74	2.52	2.14	2.90	1.81
Mid-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Off-Peak	70.7	95.15	95.21	-0.06	-0.22	0.09	-0.08
Super Off-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A
RA Window (4 to 9 PM)	**79.4**	**178.26**	**175.74**	**2.52**	**1.86**	**2.25**	**1.4%**
Day (kWh)	**72.5**	**2,699.15**	**2,687.73**	**11.41**	**7.90**	**14.92**	**0.4%**



Hour Ending	Period	Ref. MW	Treat MW	Impact MW	% Impact	Weighted Temp. (°F)	Uncertainty-adjusted Impact - Percentiles				
							10th	30th	50th	70th	90th
1	Off-Peak	92.57	93.13	-0.56	0.0%	67.7	-1.01	-0.74	-0.56	-0.38	-0.12
2	Off-Peak	80.80	81.24	-0.44	0.0%	66.9	-0.82	-0.60	-0.44	-0.29	-0.06
3	Off-Peak	73.06	73.32	-0.26	0.0%	66.2	-0.61	-0.40	-0.26	-0.11	0.10
4	Off-Peak	68.04	68.22	-0.19	0.0%	65.5	-0.50	-0.32	-0.19	-0.06	0.13
5	Off-Peak	65.84	65.95	-0.12	0.0%	64.9	-0.39	-0.23	-0.12	0.00	0.16
6	Off-Peak	67.12	67.35	-0.23	0.0%	64.4	-0.50	-0.34	-0.23	-0.13	0.03
7	Off-Peak	71.63	71.83	-0.20	0.0%	64.1	-0.54	-0.34	-0.20	-0.06	0.14
8	Off-Peak	72.82	72.73	0.08	0.0%	64.2	-0.18	-0.02	0.08	0.19	0.34
9	Off-Peak	71.60	71.94	-0.34	0.0%	66.1	-0.57	-0.43	-0.34	-0.25	-0.12
10	Off-Peak	72.20	72.79	-0.59	0.0%	69.1	-1.04	-0.78	-0.59	-0.41	-0.14
11	Off-Peak	75.56	76.01	-0.45	0.0%	72.7	-0.97	-0.67	-0.45	-0.24	0.07
12	Off-Peak	84.21	84.48	-0.27	0.0%	76.1	-0.85	-0.50	-0.27	-0.03	0.31
13	Off-Peak	100.30	100.17	0.13	0.0%	78.8	-0.66	-0.20	0.13	0.45	0.92
14	Off-Peak	119.54	119.11	0.43	0.0%	80.9	-0.42	0.08	0.43	0.78	1.28
15	Off-Peak	139.42	138.44	0.98	0.0%	82.2	0.11	0.62	0.98	1.34	1.85
16	Off-Peak	159.87	158.34	1.53	0.0%	82.7	0.67	1.18	1.53	1.88	2.39
17	Peak	176.54	174.07	2.47	0.0%	82.7	1.68	2.15	2.47	2.79	3.25
18	Peak	187.08	184.26	2.82	0.0%	81.9	2.20	2.56	2.82	3.07	3.44
19	Peak	185.86	182.91	2.95	0.0%	80.3	2.36	2.71	2.95	3.20	3.55
20	Peak	174.69	172.10	2.60	0.0%	77.9	1.98	2.34	2.60	2.85	3.21
21	Peak	167.14	165.37	1.77	0.0%	74.4	1.07	1.49	1.77	2.06	2.47
22	Off-Peak	152.42	152.08	0.34	0.0%	71.5	-0.16	0.14	0.34	0.55	0.84
23	Off-Peak	131.31	131.89	-0.59	0.0%	69.8	-1.02	-0.76	-0.59	-0.41	-0.15
24	Off-Peak	109.54	109.98	-0.44	0.0%	68.7	-0.92	-0.64	-0.44	-0.25	0.03

7.1 Enrollment Forecast

Table 7-1 summarizes the enrollment forecast for Rate 4 and Rate 5 for each LCA for January of each forecast year from 2020 through 2030. Enrollment onto Rate 4 is expected to grow through a series of waves of default enrollment between 2020 and 2022. Approximately 18% of each default wave is expected to opt out prior to enrollment, based on historical data from the launch of the pilot. After March 2022, enrollment on Rate 4 is expected to remain steady at about 2.1 million customers. As enrolled accounts close, newly opened accounts will be defaulted onto the rate. No new waves of enrollment are anticipated for Rate 5, and the population is expected to decline by approximately 1% per month (based on account closure and opt out rates observed in 2018 and 2019).

Table 7-1: Enrollment Forecast by Rate, LCA, and Forecast Year

Forecast Year	Rate 4				Rate 5			
	LA Basin	Outside LA Basin	Ventura/Big Creek	Total	LA Basin	Outside LA Basin	Ventura/Big Creek	Total
2020	101,899	8,144	17,990	**128,033**	101,419	8,248	17,661	**127,327**
2021	338,137	8,144	17,990	**364,271**	89,896	7,311	15,654	**112,861**
2022	1,459,113	116,021	256,626	**1,831,759**	79,682	6,480	13,876	**100,038**
2023	1,703,939	135,588	299,850	**2,139,377**	70,629	5,744	12,299	**88,672**
2024	1,703,939	135,588	299,850	**2,139,377**	62,605	5,091	10,902	**78,598**
2025	1,703,939	135,588	299,850	**2,139,377**	55,492	4,513	9,663	**69,668**
2026	1,703,939	135,588	299,850	**2,139,377**	49,187	4,000	8,565	**61,752**
2027	1,703,939	135,588	299,850	**2,139,377**	43,599	3,546	7,592	**54,736**
2028	1,703,939	135,588	299,850	**2,139,377**	38,645	3,143	6,730	**48,518**
2029	1,703,939	135,588	299,850	**2,139,377**	34,255	2,786	5,965	**43,005**
2030	1,703,939	135,588	299,850	**2,139,377**	30,363	2,469	5,287	**38,119**

7.2 Rate 4

Table 7-2 presents per customer ex ante load reduction estimates for the average weekday under CAISO and SCE conditions. This table and the following tables represent impact estimates expected during the RA window, from 4:00 to 9:00 PM. The greatest impacts for 1-in-2 SCE weather conditions occur in July, August, and September and are expected to be 0.02 kW. The greatest impact under 1-in-2 CAISO conditions is also 0.02 kW and occurs in the same months. Impacts are nearly identical under 1-in-10 SCE and CAISO weather conditions.

Table 7-2: Average Weekday Ex Ante Impact Estimates Per Customer – Rate 4[1]

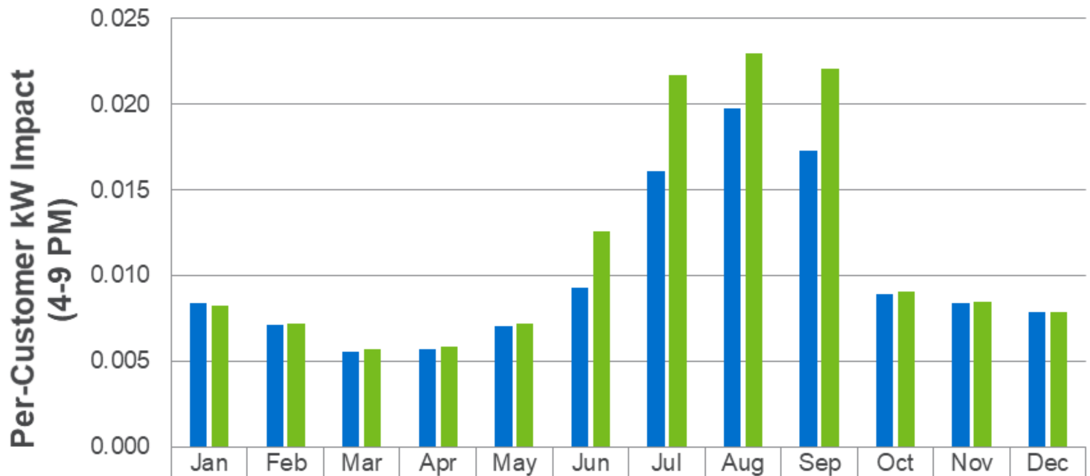
Weather Year	Month	SCE		CAISO	
		Impact (kW)	Temperature (°F)	Impact (kW)	Temperature (°F)
1-in-2	January	0.01	62.3	0.01	61.5
	February	0.01	60.7	0.01	61.8
	March	0.01	63.3	0.01	63.4
	April	0.01	65.8	0.01	66.0
	May	0.01	68.2	0.01	68.2
	June	0.01	74.0	0.01	74.0
	July	0.02	78.1	0.02	78.1
	August	0.02	79.4	0.02	79.4
	September	0.02	76.8	0.02	77.3
	October	0.01	71.5	0.01	71.5
	November	0.01	64.9	0.01	63.6
	December	0.01	57.3	0.01	56.5
1-in-10	January	0.01	56.8	0.01	56.8
	February	0.01	64.2	0.01	57.5
	March	0.01	69.4	0.01	69.4
	April	0.01	69.7	0.01	69.5
	May	0.01	73.4	0.01	73.4
	June	0.01	76.5	0.01	76.5
	July	0.02	82.5	0.02	82.5
	August	0.02	82.1	0.02	81.2
	September	0.02	80.5	0.02	80.5
	October	0.01	76.8	0.01	76.8
	November	0.01	65.8	0.01	65.8
	December	0.01	57.2	0.01	58.9

Figure 7-2 presents the average weekday impacts during the RA window under 1-in-2 and 1-in-10 SCE weather conditions with more detail. As indicated in Section 3.3, there is a positive relationship between temperature and impacts, meaning as temperatures grow warmer, impacts are expected to be greater. Generally speaking, summer temperatures are warmer under 1-in-10 conditions (versus 1-in-2), leading to greater per-customer load impacts in those months. In

[1] Impacts are representative of the mix of customers expected in January 2020.

some winter months, 1-in-2 weather conditions are warmer than 1-in-10 conditions. In these cases, 1-in-2 impacts are greater than 1-in-10 impacts.

Figure 7-2: Average Weekday Ex Ante Impact Estimates – SCE Weather, Rate 4



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SCE 1-in-2	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.01	0.01	0.01
SCE 1-in-10	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.01	0.01	0.01

Table 7-3 summarizes the aggregate ex ante load impact estimates for each month and year of the forecast. The impacts presented in this table are in MW. As described previously, impacts are expected to be greatest in the summer months. The largest expected load impact of 49.0 MW occurs in August under 1-in-10 conditions, when the ex ante weather is warmest and when enrollment is expected to be near its highest. Aggregate impacts are expected to be smallest in March and April in the earlier years of the forecast horizon.

Table 7-3: Aggregate MW Ex Ante Load Impacts by Forecast Year and Month, Rate 4

Weather Year	Forecast Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SCE 1-in-2	2020	1.1	0.9	0.7	0.7	0.9	1.2	2.0	2.5	2.2	3.0	2.9	2.9
	2021	3.0	2.7	2.1	2.1	2.3	2.8	5.1	6.9	8.2	5.8	9.4	11.5
	2022	15.4	14.8	11.8	12.2	14.9	19.7	34.1	42.1	37.1	18.9	17.9	16.7
	2023	17.9	15.3	11.8	12.2	14.9	19.7	34.1	42.1	37.1	18.9	17.9	16.7
	2024	17.9	15.3	11.8	12.2	14.9	19.7	34.1	42.1	37.1	18.9	17.9	16.7
	2025	17.9	15.3	11.8	12.2	14.9	19.7	34.1	42.1	37.1	18.9	17.9	16.7
	2026	17.9	15.3	11.8	12.2	14.9	19.7	34.1	42.1	37.1	18.9	17.9	16.7
	2027	17.9	15.3	11.8	12.2	14.9	19.7	34.1	42.1	37.1	18.9	17.9	16.7
	2028	17.9	15.3	11.8	12.2	14.9	19.7	34.1	42.1	37.1	18.9	17.9	16.7
	2029	17.9	15.3	11.8	12.2	14.9	19.7	34.1	42.1	37.1	18.9	17.9	16.7
	2030	17.9	15.3	11.8	12.2	14.9	19.7	34.1	42.1	37.1	18.9	17.9	16.7
SCE 1-in-10	2020	1.1	0.9	0.7	0.7	0.9	1.6	2.8	2.9	2.8	3.0	2.9	2.9
	2021	2.9	2.8	2.2	2.2	2.3	4.2	7.3	8.2	10.5	5.9	9.4	11.4
	2022	15.0	15.0	12.2	12.4	15.3	26.8	46.0	49.0	47.3	19.3	17.9	16.7
	2023	17.6	15.5	12.2	12.4	15.3	26.8	46.0	49.0	47.3	19.3	17.9	16.7
	2024	17.6	15.5	12.2	12.4	15.3	26.8	46.0	49.0	47.3	19.3	17.9	16.7
	2025	17.6	15.5	12.2	12.4	15.3	26.8	46.0	49.0	47.3	19.3	17.9	16.7
	2026	17.6	15.5	12.2	12.4	15.3	26.8	46.0	49.0	47.3	19.3	17.9	16.7
	2027	17.6	15.5	12.2	12.4	15.3	26.8	46.0	49.0	47.3	19.3	17.9	16.7
	2028	17.6	15.5	12.2	12.4	15.3	26.8	46.0	49.0	47.3	19.3	17.9	16.7
	2029	17.6	15.5	12.2	12.4	15.3	26.8	46.0	49.0	47.3	19.3	17.9	16.7
	2030	17.6	15.5	12.2	12.4	15.3	26.8	46.0	49.0	47.3	19.3	17.9	16.7

7.3 Rate 5

Table 7-4 summarizes the average weekday ex ante impact estimates for Rate 5 under 1-in-2 and 1-in-10 SCE and CAISO weather conditions for the RA window from 4:00 to 9:00 PM. Impacts for the Rate 5 peak period are greater than those presented which include two hours outside of the peak period for Rate 5 (5:00 to 8:00 PM). At the level of precision used here (one hundredth of a kW), the impacts for Rate 4 and Rate 5 are essentially identical and are expected to be greatest in July, August, and September under all weather conditions.

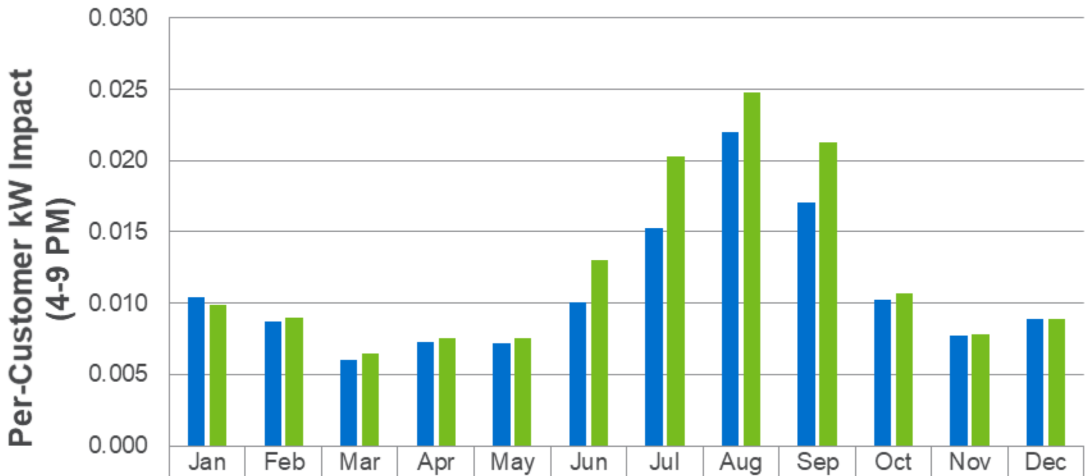
Table 7-4: Average Weekday Ex Ante Impact Estimates Per Customer– Rate 5[2]

Weather Year	Month	SCE		CAISO	
		Impact (kW)	Temperature (°F)	Impact (kW)	Temperature (°F)
1-in-2	January	0.01	62.3	0.01	61.5
	February	0.01	60.7	0.01	61.8
	March	0.01	63.3	0.01	63.4
	April	0.01	65.8	0.01	66.0
	May	0.01	68.2	0.01	68.2
	June	0.01	74.0	0.01	74.0
	July	0.02	78.1	0.02	78.1
	August	0.02	79.5	0.02	79.5
	September	0.02	76.8	0.02	77.3
	October	0.01	71.5	0.01	71.5
	November	0.01	64.9	0.01	63.6
	December	0.01	57.3	0.01	56.5
1-in-10	January	0.01	56.8	0.01	56.8
	February	0.01	64.2	0.01	57.5
	March	0.01	69.4	0.01	69.4
	April	0.01	69.7	0.01	69.5
	May	0.01	73.4	0.01	73.4
	June	0.01	76.5	0.01	76.5
	July	0.02	82.6	0.02	82.6
	August	0.02	82.1	0.02	81.2
	September	0.02	80.5	0.02	80.5
	October	0.01	76.8	0.01	76.8
	November	0.01	65.8	0.01	65.8
	December	0.01	57.2	0.01	58.8

Figure 7-3 presents the average weekday impacts during the RA window under 1-in-2 and 1-in-10 SCE weather conditions for Rate 5. Similar to Rate 4, impacts are expected to be greatest under 1-in-10 summer conditions. In the winter months, impacts between 1-in-2 and 1-in-10 weather conditions are similar.

[2] Impacts are representative of the mix of customers expected in January 2020.

Figure 7-3: Average Weekday Ex Ante Impact Estimates – SCE Weather, Rate 5



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SCE 1-in-2	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.01	0.01	0.01
SCE 1-in-10	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.01	0.01	0.01

Table 7-5 summarizes the aggregate ex ante load impact estimates for each month and year of the forecast for Rate 5. Again, the impacts presented in this table are in MW, not kW, and represent the RA period. Like Rate 4, impacts are expected to be greatest in the summer months. The largest impacts are expected in August under 1-in-10 conditions (2.9 MW). Impacts are lower in the following months as customers leave the rate.

Table 7-5: Aggregate MW Ex Ante Load Impacts by Forecast Year and Month, Rate 5

Weather Year	Forecast Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SCE 1-in-2	2020	1.3	1.1	0.7	0.9	0.9	1.2	1.8	2.6	2.0	1.2	0.9	1.0
	2021	1.2	1.0	0.7	0.8	0.8	1.1	1.6	2.3	1.8	1.0	0.8	0.9
	2022	1.0	0.9	0.6	0.7	0.7	1.0	1.4	2.0	1.6	0.9	0.7	0.8
	2023	0.9	0.8	0.5	0.6	0.6	0.8	1.3	1.8	1.4	0.8	0.6	0.7
	2024	0.8	0.7	0.5	0.6	0.5	0.8	1.1	1.6	1.2	0.7	0.5	0.6
	2025	0.7	0.6	0.4	0.5	0.5	0.7	1.0	1.4	1.1	0.6	0.5	0.6
	2026	0.6	0.5	0.4	0.4	0.4	0.6	0.9	1.3	1.0	0.6	0.4	0.5
	2027	0.6	0.5	0.3	0.4	0.4	0.5	0.8	1.1	0.9	0.5	0.4	0.4
	2028	0.5	0.4	0.3	0.3	0.3	0.5	0.7	1.0	0.8	0.5	0.3	0.4
	2029	0.4	0.4	0.3	0.3	0.3	0.4	0.6	0.9	0.7	0.4	0.3	0.3
	2030	0.4	0.3	0.2	0.3	0.3	0.4	0.5	0.8	0.6	0.4	0.3	0.3
SCE 1-in-10	2020	1.3	1.1	0.8	0.9	0.9	1.6	2.4	2.9	2.5	1.2	0.9	1.0
	2021	1.1	1.0	0.7	0.8	0.8	1.4	2.1	2.6	2.2	1.1	0.8	0.9
	2022	1.0	0.9	0.6	0.7	0.7	1.2	1.9	2.3	2.0	1.0	0.7	0.8
	2023	0.9	0.8	0.6	0.6	0.6	1.1	1.7	2.0	1.7	0.9	0.6	0.7
	2024	0.8	0.7	0.5	0.6	0.6	1.0	1.5	1.8	1.5	0.8	0.6	0.6
	2025	0.7	0.6	0.4	0.5	0.5	0.9	1.3	1.6	1.4	0.7	0.5	0.6
	2026	0.6	0.5	0.4	0.5	0.4	0.8	1.2	1.4	1.2	0.6	0.4	0.5
	2027	0.5	0.5	0.3	0.4	0.4	0.7	1.0	1.3	1.1	0.5	0.4	0.4
	2028	0.5	0.4	0.3	0.4	0.3	0.6	0.9	1.1	1.0	0.5	0.3	0.4
	2029	0.4	0.4	0.3	0.3	0.3	0.5	0.8	1.0	0.8	0.4	0.3	0.3
	2030	0.4	0.3	0.2	0.3	0.3	0.5	0.7	0.9	0.7	0.4	0.3	0.3

7.4 Comparison between Ex Post and Ex Ante

Table 7-6 facilitates a comparison of ex ante impacts to average weekday ex post load impact estimates for each month from October 2018 through September 2019 for Rate 4. Ex ante estimates for 1-in-2 and 1-in-10 SCE weather conditions are included for the corresponding calendar months. We step through an example using the “Summer” row of Table 7-6. The same logic can be used to step through the remaining rows of the table. Impacts are presented for the RA window and include an extra digit after the decimal point to allow for a more detailed comparison of the ex ante predictions versus the ex post impacts.

On average, the summer ex post impact for Rate 4 was 0.017 kW, seen in the third column of Table 7-6. However, the 2019 SCE 1-in-10 load impact for an average weekday is 0.020 kW, which is slightly higher due to the higher ex ante temperatures under the 1-in-10 conditions.

- First, on average, 0.017 kW was delivered by Rate 4 during summer months where the average temperature during the RA window was 78.0 °F.

- At those temperature conditions, a temperature of 78.0 °F, our ex ante model predicts that Rate 4 load impacts from 4:00 to 9:00 PM will be 0.017 kW. This is the same as the ex post estimate, indicating that the model predicts well using historical weather data.
- Under the 1-in-10 conditions, the temperature of 80.4 °F is higher than the ex post temperature. Accordingly, the ex ante 1-in-10 load impact of 0.020 is higher than the ex post impact.

Table 7-6: Comparison of Ex Post and Ex Ante Aggregate Impacts – Rate 4

Month	Ex Post Temperature (°F)	Ex Post Impact (kW)	Ex Post Weather, Predicted Impact (kW)	1-in-2		1-in-10	
				Temperature (°F)	Impact (kW)	Temperature (°F)	Impact (kW)
January	59.2	0.008	0.008	62.3	0.008	56.8	0.008
February	54.7	0.007	0.007	60.7	0.007	64.2	0.007
March	61.8	0.005	0.005	63.3	0.006	69.4	0.006
April	67.4	0.006	0.006	65.8	0.006	69.7	0.006
May	65.5	0.007	0.007	68.2	0.007	73.4	0.007
June	73.1	0.008	0.008	74.0	0.009	76.5	0.013
July	79.8	0.018	0.018	78.1	0.016	82.5	0.022
August	81.0	0.022	0.022	79.4	0.020	82.1	0.023
September	77.9	0.020	0.019	76.8	0.017	80.5	0.022
October	72.9	0.010	0.009	71.5	0.009	76.8	0.009
November	66.7	0.009	0.008	64.9	0.008	65.8	0.008
December	59.5	0.009	0.008	57.3	0.008	57.2	0.008
Summer	**78.0**	**0.017**	**0.017**	**77.1**	**0.016**	**80.4**	**0.020**
Winter	**63.5**	**0.008**	**0.007**	**64.2**	**0.007**	**66.7**	**0.007**
Annual	**68.3**	**0.011**	**0.010**	**68.5**	**0.010**	**71.3**	**0.012**

Table 7-7 presents a similar comparison of ex post and ex ante estimates for Rate 5. Again, impacts are presented for the RA window from 4:00 to 9:00 PM, not the Rate 5 peak period which includes the hours from 5:00 PM to 8:00 PM. The average ex post and predicted ex post impact in the summer months is 0.017, indicating that the ex ante model accurately predicts load impacts under historical weather conditions. The same is true in the winter months and the year as a whole. Ex ante impacts are expected to be smaller than ex post impacts under 1-in-2 weather conditions, but only slightly. The difference in temperatures between ex post and 1-in-2 weather conditions is very small. Conversely, load impacts are expected to be greater during 1-in-10 summer months, when temperatures are expected to be warmer than summer 2019.

Table 7-7: Comparison of Ex Post and Ex Ante Aggregate Impacts – Rate 5

Month	Ex Post Temperature (°F)	Ex Post Impact (kW)	Ex Post Weather, Predicted Impact (kW)	1-in-2		1-in-10	
				Temperature (°F)	Impact (kW)	Temperature (°F)	Impact (kW)
January	59.2	0.010	0.010	62.3	0.010	56.8	0.010
February	54.7	0.008	0.008	60.7	0.009	64.2	0.009
March	61.8	0.006	0.006	63.3	0.006	69.4	0.007
April	67.4	0.008	0.007	65.8	0.007	69.7	0.008
May	65.5	0.007	0.007	68.2	0.007	73.4	0.008
June	73.1	0.009	0.009	74.0	0.010	76.5	0.013
July	79.8	0.017	0.017	78.1	0.015	82.6	0.020
August	81.0	0.024	0.024	79.5	0.022	82.1	0.025
September	77.9	0.019	0.018	76.8	0.017	80.5	0.021
October	72.9	0.011	0.010	71.5	0.010	76.8	0.011
November	66.7	0.008	0.008	64.9	0.008	65.8	0.008
December	59.5	0.010	0.009	57.3	0.009	57.2	0.009
Summer	**78.0**	**0.017**	**0.017**	**77.1**	**0.016**	**80.4**	**0.020**
Winter	**63.5**	**0.008**	**0.008**	**64.2**	**0.008**	**66.7**	**0.008**
Annual	**68.3**	**0.011**	**0.011**	**68.5**	**0.011**	**71.3**	**0.012**

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