REPORT

2020 Load Impact Evaluation of Southern California Edison's Default Time-of-Use Pilot

Prepared for:

Southern California Edison Co.
April 1, 2021

Principal authors:

Eric Bell, Ph.D., Vice President
Aimee Savage, Senior Consultant
Daniel Lesperance, Project Analyst I

CALMAC Study ID SCE0450

Contents

List of Figures

List of Tables

Equations

1 Executive Summary

This report documents the 2020 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. Findings from the second summer can be found in the 2019 evaluation report.[1]

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 winter of 2019/2020 (October 2019 through May 2020) and summer of 2020 (June through September 2020). An additional objective is to provide an ex ante (forward looking) forecast for the next eleven years (2021 to 2031) 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

[1] *2019 Load Impact Evaluation of Southern California Edison's Default Time-of-Use Pilot.* Nexant. April 1, 2020.

be defaulted on. If a customer took no action, they were placed on the default rate associated with their assigned group.[2]

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 7¢/kWh that applies to each rate.[3]

Figure 1-1 Default Pilot Rate 4[4]

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 (25¢)																Peak (40¢)							
	Winter	Off-Peak (24¢)								Super Off-Peak (22¢)								Mid-Peak (32¢)							
Weekend	Summer	Off-Peak (25¢)																Mid-Peak (33¢)							
	Winter	Off-Peak (24¢)								Super Off-Peak (22¢)								Mid-Peak (32¢)							

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 (25¢)																	Peak (50¢)						
	Winter	Off-Peak (25¢)								Super Off-Peak (22¢)									Mid-Peak (38¢)						
Weekend	Summer	Off-Peak (25¢)																	Mid-Peak (38¢)						
	Winter	Off-Peak (25¢)								Super Off-Peak (22¢)									Mid-Peak (38¢)						

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). 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 (NEM) and non-net metered (non-NEM) customers.

---

[2] Nexant was informed that during the summer of 2020 a small portion of customers originally designated as control group customers for the Default TOU Pilot evaluation received notification about being defaulted onto a TOU rate beginning October 1, 2020. Nexant does not believe these notifications influenced the load impact estimates in this evaluation in a substantive manner, and provides documentation and analysis supporting this position in Appendix A.

[3] The baseline credit was equal to 7.027¢/kWh on January 1, 2020 and rose to 7.576¢/kWh on June 1, 2020.

[4] Winter rates effective Jan 1, 2020. Summer rates effective June 1, 2020.

1.2 Overall Findings

1.2.1 Ex Post Load Impacts

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

Metric	Rate 4		Rate 5	
	Winter	Summer	Winter	Summer
Peak Period Hours	4-9 PM	4-9 PM	5-8 PM	5-8 PM
% Impact	0.6%	1.1%	0.9%	1.3%
Absolute Impact (kW)	0.006 kW	0.016 kW	0.008 kW	0.019 kW

Key findings pertaining to the ex post analysis include:

- Default customers on both Rates 4 and 5 produced statistically significant, peak-period load reductions during the summer and winter seasons. Summer peak period load reductions were equal to 1.1% for Rate 4 and 1.3% for Rate 5. Winter peak period load reductions were slightly smaller, and averaged 0.6% for Rate 4 and 0.9% 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 in both seasons, 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 in the winter months but not during the summer.
- Statistically significant but small reductions in summer daily electricity use were found for the pilot populations as a whole and in Climate Zone 10, for both Rate 4 and Rate 5. Customers on Rate 4 in the moderate climate region increased their daily summer consumption by a small but statistically significant amount. Daily kWh impacts were mixed in the winter months: Rate 4 customers increased their daily kWh consumption and Rate 5 customers did not have statistically significant impacts.
- Peak period load reductions were largest in Climate Zone 10 in both summer and winter, but this segment did not include CARE/FERA customers. In the summer months, impacts were smallest in the hot and cool climate regions, and in the winter months impacts were smallest in the moderate and cool climate regions.
- In the summer months, peak period impacts were greatest in the Outside LA Basin region, however the difference between the Outside LA Basin region and the other two LCAs was not statistically significant (with the exception of Ventura/Big Creek for Rate 4, in absolute terms). In the winter months, the Outside LA Basin had the smallest load impacts.
- Rate 4 and Rate 5 NEM customers had statistically significant peak period load reductions equal to 2.2% and 3.4%, respectively, in the summer months. NEM customers on Rate 4 had small but statistically significant load increases in the winter (0.7%). Rate 5 NEM customers, on the other hand, had statistically significant peak load reductions in the winter (3.3%).

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 the three summer seasons observed (2018, 2019, and 2020). At the service territory level, load impacts were greatest in the first summer (2018) and smallest in the most recent summer (2020). Customers on Rate 4 had load reductions equal to 1.5% in the first summer, 1.2% in the second summer, and 1.0% in the third summer. Rate 5 peak period impacts were 2.0% in 2018, 1.6% in 2019, and 1.1% in 2020. While the weather was slightly cooler on average in 2019 and 2020 compared to 2018, the load impacts were lower in 2019 and 2020 at comparable temperatures indicating second and third summer impacts were slightly lower when accounting for differences in weather. The summer season in 2020 coincided with the COVID-19 pandemic, which likely had an effect on customers' ability or motivation to respond to the TOU rate structure.
- The load impacts for the different climate regions on the two rates were generally smallest in the third summer compared to the first and second summers. The exception was customers on Rate 4 in the moderate climate region whose load impact increases from 2019 to 2020, but the differences are not statistically significant.

1.2.3 Ex Ante Load Impacts

Key findings pertaining to the ex ante analysis include:

- Enrollment on Rate 4 and Rate 5 will reach approximately 2.5 million by 2023 and then slowly decline to about 2.3 million by 2031 through natural attrition (approximately 1% per month). New enrollees will come from large waves of default enrollments (1.8 million) and new SCE customers (21,600 per month).
- Generally speaking, ex post and ex ante load impacts are larger under higher temperatures. As such, the largest ex ante impacts (0.019 to 0.027 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 impacts are expected to be similar under 1-in-2 and 1-in-10 weather conditions.
- Ex ante forecasts account for the potential effects of the COVID-19 pandemic on customer demand and load impacts. Per-customer load impacts are expected to increase as the COVID-19 effect diminishes.
- The ex post load impacts fall between the ex ante load impacts under SCE 1-in-2 and SCE 1-in-10 weather conditions. This finding is expected as the average monthly temperatures between October 2019 and September 2020 are warmer than 1-in-2 conditions but cooler than 1-in-10 conditions.
- In 2022, after the default is completed, Rate 4 impacts are forecasted to reach 33.5 MW on the average August weekday under SCE 1-in-10 weather conditions and 26.6 MW under SCE 1-in-2 weather conditions during the resource adequacy window (4:00 to 9:00 PM). Rate 5 impacts during the RA window under SCE 1-in-10 weather conditions decline from a peak of 29.4 MW in August 2022 to 13.6 MW in August 2031 as the population grows smaller.
- For the default TOU rates as a whole (Rate 4 and Rate 5), aggregate impacts are expected to reach a maximum under August 1-in-2 conditions of 51.1 MW in 2024, and a maximum under August 1-in-10 conditions of 63.6 MW in 2023.

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. Findings from the second summer can be found in the 2019 evaluation report.[5]

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 7¢/kWh that applies to each rate.[6]

Figure 2-1 Default Pilot Rate 4[7]

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 (25¢)																Peak (40¢)							
	Winter	Off-Peak (24¢)								Super Off-Peak (22¢)								Mid-Peak (32¢)							
Weekend	Summer	Off-Peak (25¢)																Mid-Peak (33¢)							
	Winter	Off-Peak (24¢)								Super Off-Peak (22¢)								Mid-Peak (32¢)							

[5] *2019 Load Impact Evaluation of Southern California Edison's Default Time-of-Use Pilot.* Nexant. April 1, 2020.

[6] The baseline credit was equal to 7.027¢/kWh on January 1, 2020 and rose to 7.576¢/kWh on June 1, 2020.

[7] Winter rates effective Jan 1, 2020. Summer rate effective Jun 1, 2020.

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 (25¢)																	Peak (50¢)						
	Winter	Off-Peak (25¢)								Super Off-Peak (22¢)									Mid-Peak (38¢)						
Weekend	Summer	Off-Peak (25¢)																	Mid-Peak (38¢)						
	Winter	Off-Peak (25¢)								Super Off-Peak (22¢)									Mid-Peak (38¢)						

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 1.6 to 1 in summer and mid-peak to super off-peak ratio is 1.5 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 (50¢/kWh for Rate 5 versus 40¢/kWh for Rate 4) and slightly high mid-peak price in winter months (38¢/kWh for Rate 5 versus 32¢/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 22¢/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 to 1. In winter, the mid-peak to super off-peak price ratio is roughly 1.7 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). 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 (NEM) and non-net metered (non-NEM) customers.

2.1 Evaluation Objectives

The primary objectives of the 2020 D-TOU load impact evaluation are to:

- Estimate hourly ex post load impacts for the winter period from October 2019 to May 2020 and the summer period from June to September 2020;
- Forecast 2021-2031 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), SCE local capacity area (LCA), and for net metered (NEM) and non-net metered (non-NEM) customers;
- 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) [8] 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).[9]

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 2020.

The ex ante evaluation incorporates information from the launch of the pilot (March 2018) through September 2020. Nexant developed a simple impact model that estimates how default TOU ex post load impacts vary as a function of weather. To produce the ex ante load impact forecasts, Nexant applied this weather-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.

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

[9] 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.

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 PY2020 summer and winter periods (October 1st, 2019 through September 30, 2020), and ex ante impacts for 1-in-2 and 1-in-10 year weather conditions for 2021 through 2031. The persistence of load impacts for customers who remained active accounts from the launch of the pilot through the end of September 2020 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.

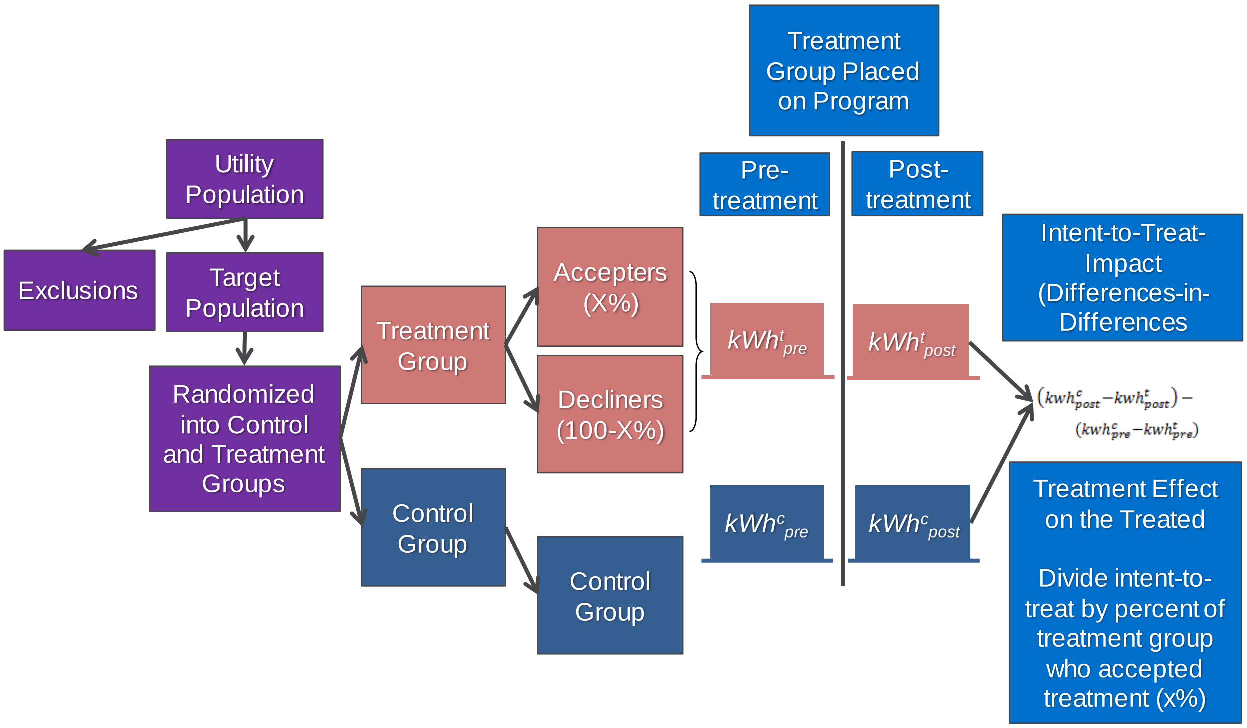
3.1 Ex Post Load Impacts Methodology

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. Ex post load impacts are also reported for each LCA in SCE's service territory and for NEM and 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).[10] A conceptual overview of the RED design and analysis for estimating load impacts is shown in Figure 3-1.

[10] 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.[11] Implementing a DiD through simple arithmetic would yield the same point estimate but it would not generate confidence intervals.

[11] 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

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

In the above equation, the variable $kW_{i,t}$ 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 *treatpost* 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 α_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.[12] 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

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

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

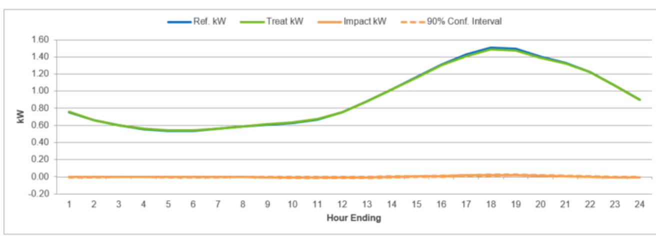
Figure 3-2 displays an image from an Excel spreadsheet containing the output that is produced for each rate treatment, customer segment, climate region, day type, and month covered by this interim analysis. These Excel spreadsheets are available upon request through the CPUC. Pull down menus in the upper 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	156,116	118,831	1.43	1.42	0.016	0.01	0.02	1.1%
Mid-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Off-Peak	156,116	118,831	0.79	0.79	-0.002	0.00	0.00	-0.3%
Super Off-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Day (kWh)	**156,116**	**118,831**	**22.14**	**22.11**	**0.039**	**0.02**	**0.06**	**0.2%**



Hour	Period	Ref. kW	Treat kW	Impact kW	% Impact	Weighted Temp. (°F)	Uncertainty-adjusted Impact - Percentiles				
							10th	30th	50th	70th	90th
1	Off-Peak	0.75	0.757	-0.002	-0.3%	67.8	0.00	0.00	0.00	0.00	0.00
2	Off-Peak	0.66	0.663	-0.002	-0.3%	67.1	0.00	0.00	0.00	0.00	0.00
3	Off-Peak	0.60	0.599	-0.001	-0.2%	66.5	0.00	0.00	0.00	0.00	0.00
4	Off-Peak	0.56	0.559	-0.001	-0.2%	66.0	0.00	0.00	0.00	0.00	0.00
5	Off-Peak	0.54	0.539	-0.002	-0.4%	65.6	0.00	0.00	0.00	0.00	0.00
6	Off-Peak	0.54	0.541	-0.002	-0.4%	65.3	0.00	0.00	0.00	0.00	0.00
7	Off-Peak	0.56	0.562	-0.003	-0.5%	65.3	0.00	0.00	0.00	0.00	0.00
8	Off-Peak	0.59	0.586	-0.001	-0.1%	66.4	0.00	0.00	0.00	0.00	0.00
9	Off-Peak	0.61	0.612	-0.004	-0.7%	68.7	-0.01	-0.01	0.00	0.00	0.00
10	Off-Peak	0.63	0.634	-0.006	-1.0%	71.7	-0.01	-0.01	-0.01	-0.01	0.00
11	Off-Peak	0.67	0.674	-0.006	-0.9%	74.9	-0.01	-0.01	-0.01	0.00	0.00
12	Off-Peak	0.75	0.757	-0.006	-0.9%	77.6	-0.01	-0.01	-0.01	0.00	0.00
13	Off-Peak	0.88	0.881	-0.005	-0.5%	79.6	-0.01	-0.01	0.00	0.00	0.00
14	Off-Peak	1.02	1.019	-0.002	-0.2%	81.1	-0.01	0.00	0.00	0.00	0.00
15	Off-Peak	1.16	1.159	0.003	0.3%	81.9	0.00	0.00	0.00	0.01	0.01
16	Off-Peak	1.31	1.300	0.008	0.6%	82.2	0.00	0.01	0.01	0.01	0.01
17	Peak	1.43	1.409	0.017	1.2%	81.7	0.01	0.02	0.02	0.02	0.02
18	Peak	1.51	1.486	0.019	1.3%	80.4	0.02	0.02	0.02	0.02	0.02
19	Peak	1.49	1.474	0.020	1.4%	78.3	0.02	0.02	0.02	0.02	0.02
20	Peak	1.40	1.387	0.015	1.1%	75.5	0.01	0.01	0.01	0.02	0.02
21	Peak	1.33	1.321	0.010	0.7%	72.7	0.01	0.01	0.01	0.01	0.01
22	Off-Peak	1.22	1.221	0.000	0.0%	70.9	0.00	0.00	0.00	0.00	0.00
23	Off-Peak	1.06	1.066	-0.004	-0.4%	69.7	-0.01	-0.01	0.00	0.00	0.00
24	Off-Peak	0.90	0.901	-0.004	-0.5%	68.7	-0.01	-0.01	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 or 2019 with those enrolled in 2020 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 2020. 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.

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.[13] 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 March 2018 through September 2020 were developed using the fixed effects regression methodology described in Section 3.1;
- Next, the relationship between ex post load impacts and weather is estimated for each hour of the day, each season (summer/winter) and each customer segment and rate; [14]
- Then, ex ante weather conditions are used as inputs 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[15] (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

[13] 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.

[14] Months where COVID-19 stay-at-home orders were in effect are accounted for in the model.

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

were updated in 2019 along with the development of the new CAISO based conditions. Both sets of estimates use a common methodology, which is documented in a report delivered to the IOUs.[16]

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 Estimating COVID-19 Effects

The COVID-19 pandemic is expected to have a continued effect on residential customer demand and peak period impacts. To estimate the effects of the pandemic on customer impacts (and demand), a COVID-19 indicator was included in the ex ante model. In the historical data used to fit the model, the indicator is equal to zero for all months prior to March 2020. For March 2020 through September 2020 (the end of the analysis period), the COVID-19 indicator is equal to one.

As shown in Table 3-1, the COVID-19 effect is expected to decline between 2021 and 2028. In 2021, for example, the effect is expected to be half (0.5) of what it was in 2020. In 2022, the effect is expected to be one fourth of what it was in 2020. Finally, by 2028, the effect is expected to be negligible.

Table 3-1: Progression of COVID-19 Indicator from 2020 to 2031[17]

Year	COVID-19 Indicator
2020 (ex post, Mar-Sept)	1.00
2021	0.50
2022	0.25
2023	0.13
2024	0.06
2025	0.03
2026	0.02
2027	0.01
2028	0.00
2029	0.00
2030	0.00
2031	0.00

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

[17] The COVID-19 indicator values were developed by SCE Load Forecasting and were provided to SCE demand response evaluators for their ex ante forecasts.

3.3.3 Estimating Ex Ante Load Impacts

Ex ante impact estimates were calculated by making predictions for ex ante weather conditions using a regression model of weekly ex post impacts from 2018, 2019, and 2020. 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 March 2018 through September 2020. The independent variables for each hour were *mean17* and *mean17*^{2}, a COVID-19 indicator, and a binary indicator for the calendar month. *Mean17* is equal to the average temperature from midnight to 5 PM. It is designed to measure heat buildup throughout the day and there is a positive relationship between *mean17* and load impacts. The model specification is presented in Equation 3-2:[18]

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

$$Impact_{h,m} = a_h + b \cdot mean17_m + c \cdot mean17^2{}_m + \sum_{m=1}^{12} d_m \cdot month_m + e \cdot covid_m + \varepsilon_{h,m}$$

Table 3-2: Description of Ex Ante Load Impact Regression Variables

Variable	Description
$Impact_{h,m}$	Per customer ex post load impact for each week, for the hour h in month m
a_h	Estimated constant
b through e	Estimated parameter coefficients
$mean17$	Average temperature from midnight to 5:00 PM
$mean17^2$	Average temperature from midnight to 5:00 PM, squared
$month_m$	A binary indicator for each month m of the year, January through December, for the hour h of interest
$covid$	An indicator for each month m, equal to 1 from March – September 2020
$\varepsilon_{h,m}$	The error term for each month m, and hour h of interest, assumed to be a mean zero and uncorrelated with any of the independent variables

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.

[18] 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.

Figure 3-3 illustrates the relationships between summer *mean17* estimates (average temperature from 12 AM to 5 PM) and per customer peak period load impacts for Rate 4 and Rate 5 customers. Figure 3-4 illustrates the winter relationships between *mean17* and per customer peak period load impacts for Rate 4 and Rate 5 customers.

Figure 3-3: Summer Peak Period Ex Post Impact versus Mean17 – Rate 4 and Rate 5

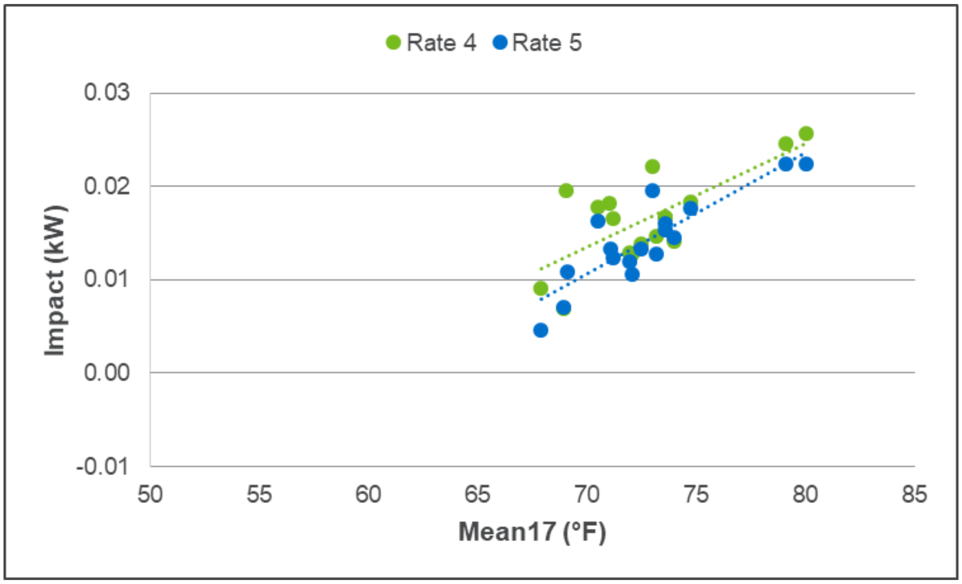
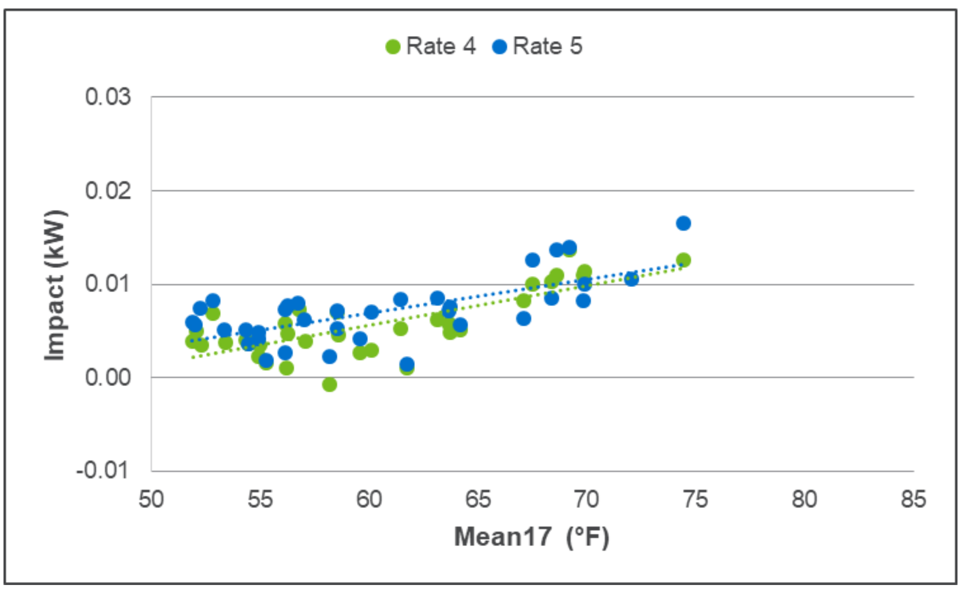


Figure 3-4: Winter Peak Period Ex Post Impact versus Mean17 – Rate 4 and Rate 5



4 Customer Attrition

This section summarizes customer post-enrollment opt-out rates for each rate tested by SCE. SCE currently considers customers who move from their defaulted rate to another rate a rate change, not an opt-out. The term “opt-out” has been used in each evaluation since the Interim Report and is used here for consistency. In this section, an opt-out occurs when a customer moves from Rate 4 or Rate 5 to any other rate. A customer who moves from Rate 4 to Rate 5 (or vice versa) is not considered an opt-out. 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 third summer of the pilot (September 2020). 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 3.2% and 5.2%. 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 with non-CARE/FERA customers opting out at a higher rate.

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. However, there was a small increase in opt-out rates in June 2019, which coincided with bill protection expiration notifications and was the start of the 2019 summer season. 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[19]

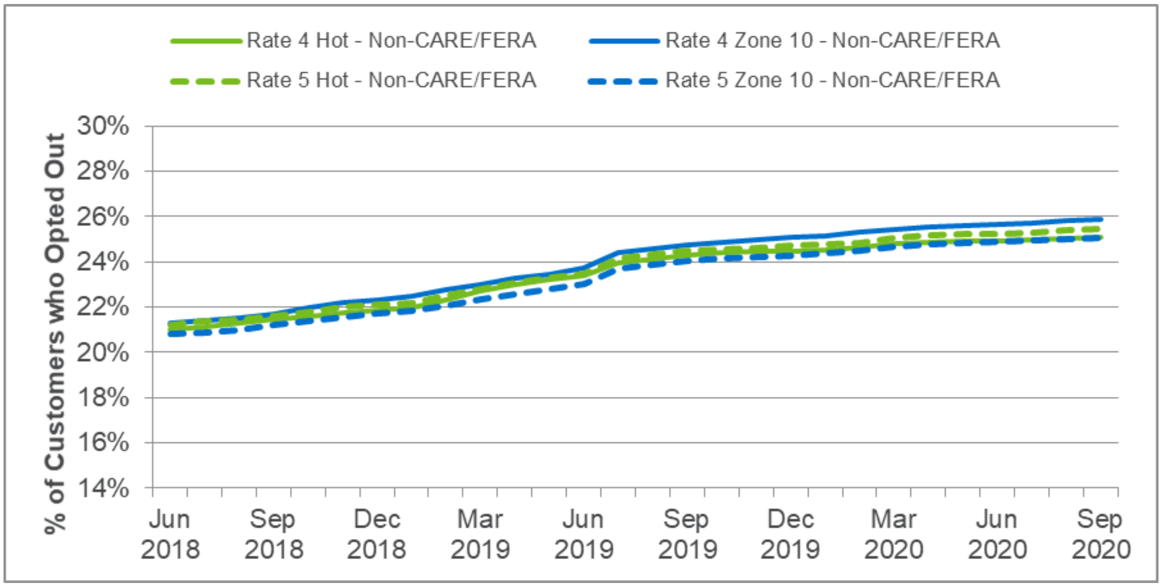
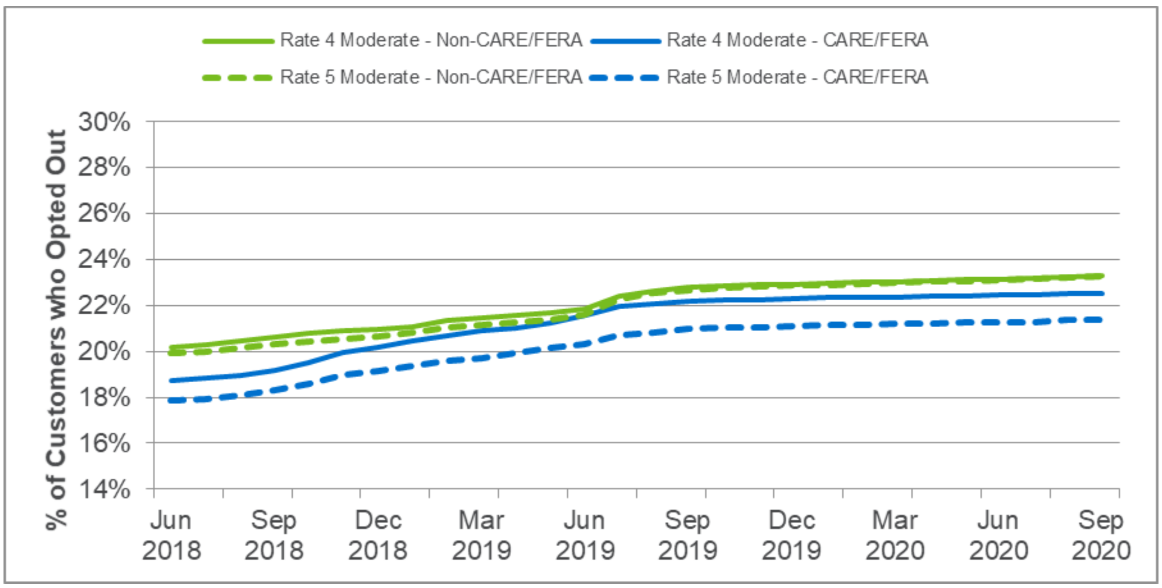
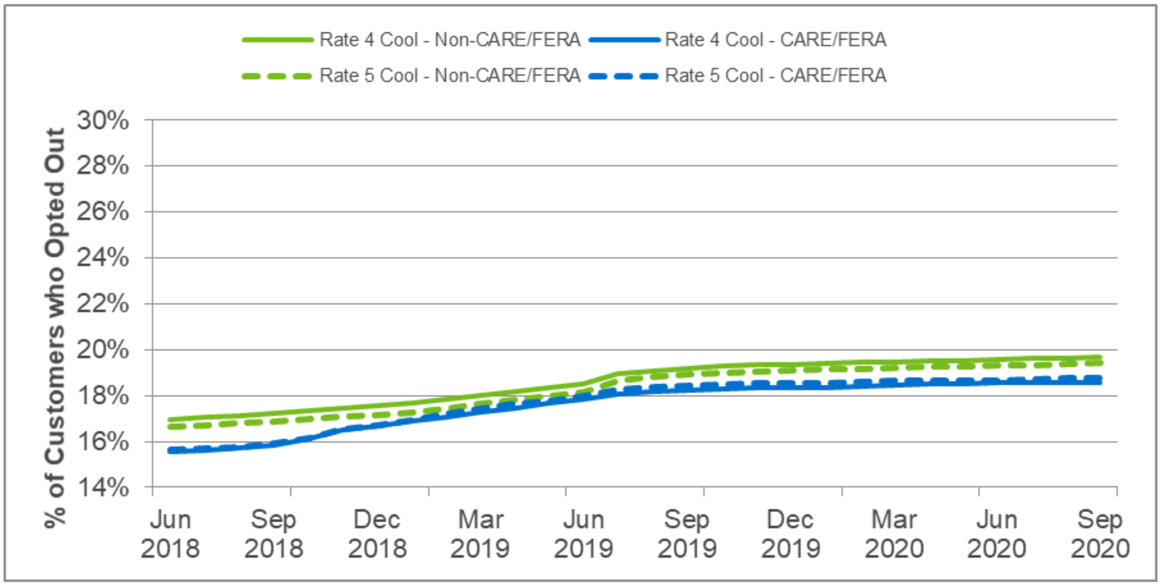


Figure 4-2: Cumulative Opt-Out Rates for Moderate Climate Region



[19] Opt-out rates here present customers who opted out to a rate other than Rate 4 or Rate 5.

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);
- 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. 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.

Ex post load impacts are reported here for each rate period for the average weekday, average weekend, and average monthly peak day for the winter months of October 2019 through May 2020 and summer months of June 2020 through September 2020. Impacts are reported for each rate, climate region, customer segment and LCA summarized above.

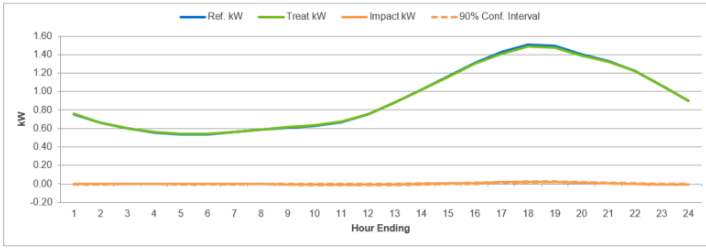
Underlying the values presented in the report are electronic tables that contain estimates for each hour of the day for each day type, segment, and climate region for the summer; and for each month separately. These values are contained in Excel spreadsheets that are available upon request through the 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 2020 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	156,116	118,831	1.43	1.42	0.016	0.01	0.02	1.1%
Mid-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Off-Peak	156,116	118,831	0.79	0.79	-0.002	0.00	0.00	-0.3%
Super Off-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Day (kWh)	**156,116**	**118,831**	**22.14**	**22.11**	**0.039**	**0.02**	**0.06**	**0.2%**



Hour	Period	Ref. kW	Treat kW	Impact kW	% Impact	Weighted Temp. (°F)	Uncertainty-adjusted Impact - Percentiles				
							10th	30th	50th	70th	90th
1	Off-Peak	0.75	0.757	-0.002	-0.3%	67.8	0.00	0.00	0.00	0.00	0.00
2	Off-Peak	0.66	0.663	-0.002	-0.3%	67.1	0.00	0.00	0.00	0.00	0.00
3	Off-Peak	0.60	0.599	-0.001	-0.2%	66.5	0.00	0.00	0.00	0.00	0.00
4	Off-Peak	0.56	0.559	-0.001	-0.2%	66.0	0.00	0.00	0.00	0.00	0.00
5	Off-Peak	0.54	0.539	-0.002	-0.4%	65.6	0.00	0.00	0.00	0.00	0.00
6	Off-Peak	0.54	0.541	-0.002	-0.4%	65.3	0.00	0.00	0.00	0.00	0.00
7	Off-Peak	0.56	0.562	-0.003	-0.5%	65.3	0.00	0.00	0.00	0.00	0.00
8	Off-Peak	0.59	0.586	-0.001	-0.1%	66.4	0.00	0.00	0.00	0.00	0.00
9	Off-Peak	0.61	0.612	-0.004	-0.7%	68.7	-0.01	-0.01	0.00	0.00	0.00
10	Off-Peak	0.63	0.634	-0.006	-1.0%	71.7	-0.01	-0.01	-0.01	-0.01	0.00
11	Off-Peak	0.67	0.674	-0.006	-0.9%	74.9	-0.01	-0.01	-0.01	0.00	0.00
12	Off-Peak	0.75	0.757	-0.006	-0.9%	77.6	-0.01	-0.01	-0.01	0.00	0.00
13	Off-Peak	0.88	0.881	-0.005	-0.5%	79.6	-0.01	-0.01	0.00	0.00	0.00
14	Off-Peak	1.02	1.019	-0.002	-0.2%	81.1	-0.01	0.00	0.00	0.00	0.00
15	Off-Peak	1.16	1.159	0.003	0.3%	81.9	0.00	0.00	0.00	0.01	0.01
16	Off-Peak	1.31	1.300	0.008	0.6%	82.2	0.00	0.01	0.01	0.01	0.01
17	Peak	1.43	1.409	0.017	1.2%	81.7	0.01	0.02	0.02	0.02	0.02
18	Peak	1.51	1.486	0.019	1.3%	80.4	0.02	0.02	0.02	0.02	0.02
19	Peak	1.49	1.474	0.020	1.4%	78.3	0.02	0.02	0.02	0.02	0.02
20	Peak	1.40	1.387	0.015	1.1%	75.5	0.01	0.01	0.01	0.02	0.02
21	Peak	1.33	1.321	0.010	0.7%	72.7	0.01	0.01	0.01	0.01	0.01
22	Off-Peak	1.22	1.221	0.000	0.0%	70.9	0.00	0.00	0.00	0.00	0.00
23	Off-Peak	1.06	1.066	-0.004	-0.4%	69.7	-0.01	-0.01	0.00	0.00	0.00
24	Off-Peak	0.90	0.901	-0.004	-0.5%	68.7	-0.01	-0.01	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 7¢/kWh that applies to each rate.[20]

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 1.6 to 1 in summer and mid-peak to super off-peak ratio is roughly 1.5 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 (50¢/kWh for Rate 5 versus 40¢/kWh for Rate 4) and slightly high mid-peak price in winter months (38¢/kWh for Rate 5 versus 32¢/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 22¢/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 to 1. In winter, the mid-peak to super off-peak price ratio is roughly 1.7 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.

[20] The baseline credit was equal to 7.027¢/kWh on January 1, 2020 and rose to 7.576¢/kWh on June 1, 2020.

5.2 Rate 4

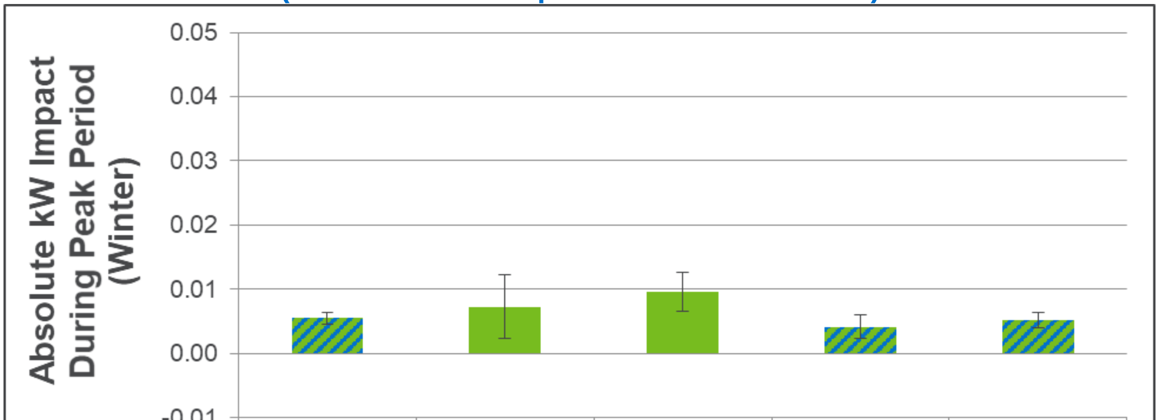
5.2.1 Load Impacts by Pilot Segment

Figure 5-2 shows the winter 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 zero, it means that the estimated load impact is not statistically different from zero 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. In these cases, t-tests were calculated to determine whether the difference is statistically significant.[21] 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.

As seen in Figure 5-2 the winter 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 0.6% or 0.006 kW, across the five-hour peak period from 4 PM to 9 PM. 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 1.0% and 0.010 kW in Climate Zone 10 to a low of about 0.5% and 0.004 kW in the moderate climate region. The difference in load impacts between the moderate and cool climate regions and the difference between the hot climate region and Climate Zone 10 are not statistically significant in absolute terms or percentage terms.

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

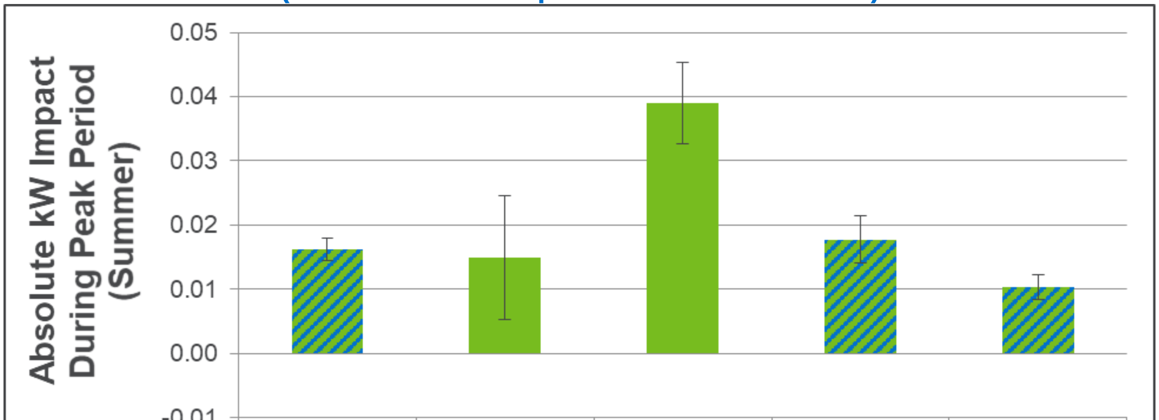
Figure 5-2: Winter Average Peak Period Load Impacts for Rate 4 by Climate Region (Positive values represent load reductions)



	All	Hot	Zone10	Moderate	Cool
Percent Impact	0.6%	0.8%	1.0%	0.5%	0.6%
Absolute Impact	0.006	0.007	0.010	0.004	0.005

Figure 5-3 presents average peak-period load impacts during the summer months for the service territory as a whole and for each climate region. Peak period load impacts were statistically significant at the 90% level of confidence for the full service territory and in each climate region. On average, default pilot participants across SCE's service territory on Rate 4 reduced peak-period electricity use by 1.1%, or 0.016 kW, across the five-hour peak period from 4 PM to 9 PM. 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 1.8% and 0.039 kW in Climate Zone 10 to a low of about 0.7% and 0.015 kW in the hot climate region and 0.9% and 0.010 kW in the cool climate region. The difference in load impacts between the moderate and cool climate regions is statistically significant in absolute terms (but not in percentage terms). The difference in impacts between Climate Zone 10 and the hot climate region were also statistically significant in percentage and absolute terms.

Figure 5-3: Summer Average Peak Period Load Impacts for Rate 4 by Climate Region (Positive values represent load reductions)

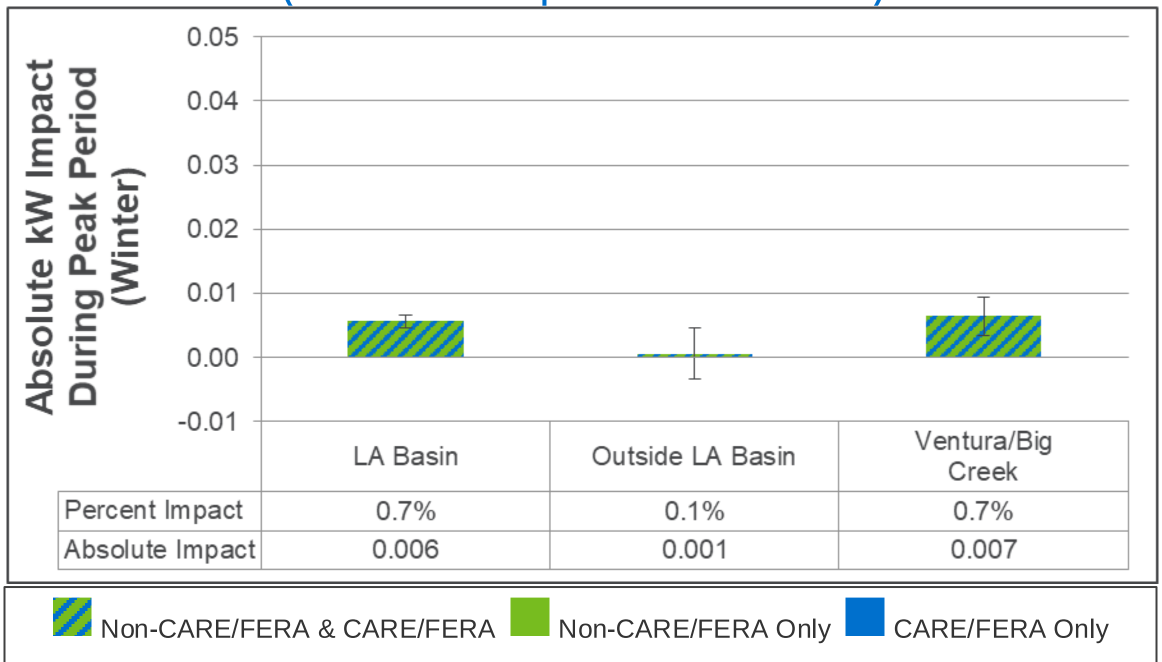


	All	Hot	Zone10	Moderate	Cool
Percent Impact	1.1%	0.7%	1.8%	1.1%	0.9%
Absolute Impact	0.016	0.015	0.039	0.018	0.010

5.2.2 Load Impacts by LCA

Figure 5-4 shows the winter 2019/2020 peak period load impacts for Rate 4 for each LCA. 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. Peak period load impacts were largest in the Ventura/Big Creek LCA with impacts equal to 0.7% or 0.007 kW and impacts were smallest in the Outside LA Basin LCA with impacts equal to 0.1% or 0.001 kW. The absolute impacts in the LA Basin and Ventura/Big Creek LCAs were statistically significant from zero, while the absolute impacts Outside LA Basin were not. The differences between the LA Basin and Ventura/Big Creek LCAs are not statistically significantly different from each other (in both percentage and absolute terms), but they are both significantly different from the Outside LA Basin LCA (in both percentage and absolute terms)

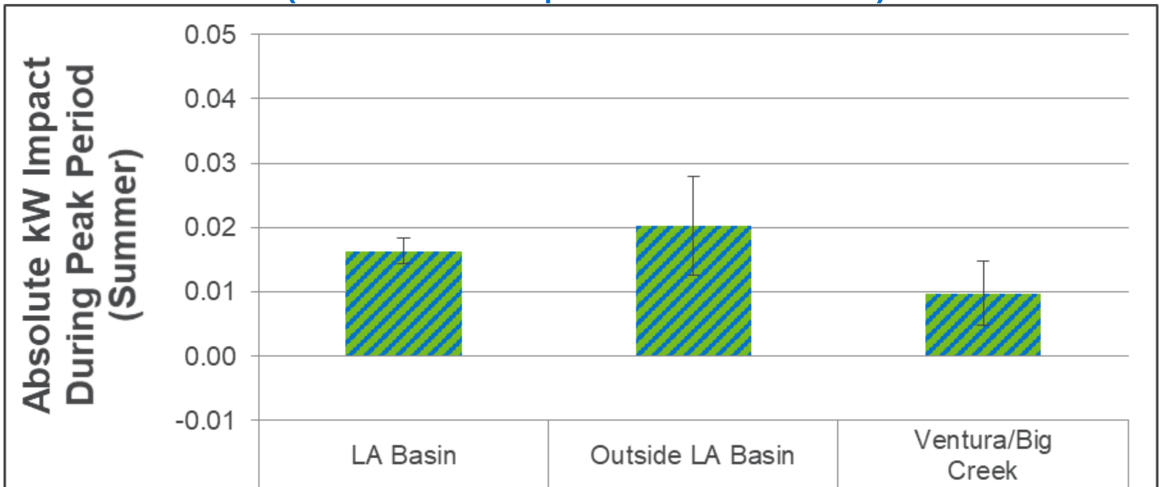
Figure 5-4: Average Winter Peak Period Load Impacts for Rate 4 by LCA (Positive values represent load reductions)



	LA Basin	Outside LA Basin	Ventura/Big Creek
Percent Impact	0.7%	0.1%	0.7%
Absolute Impact	0.006	0.001	0.007

Figure 5-5 shows the summer 2020 peak period load impacts for Rate 4 for each LCA. Peak period impacts were statistically significant across all three LCAs. Load impacts were largest (in percentage terms) in the LA Basin and Outside LA Basin LCAs with impacts equal to 1.2% or 0.016 kW and 0.020 kW, respectively. Peak period impacts were smallest (in percent and absolute terms) in the Ventura/Big Creek LCA with percent impacts equal to 0.7% or 0.010 kW. The load impacts in Ventura/ Big Creek were statistically significantly different in absolute terms from the LA Basin and Outside LA Basin LCAs (while also being statistically significantly different from the Outside LA Basin LCA in percentage terms).

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



	LA Basin	Outside LA Basin	Ventura/Big Creek
Percent Impact	1.2%	1.2%	0.7%
Absolute Impact	0.016	0.020	0.010

5.2.3 Load Impacts by NEM and Non-NEM

Figure 5-6 presents average winter 2019/2020 weekday peak period load reductions for net NEM and 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 2020). 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. Non-NEM customers had statistically significant winter peak period load impacts equal to 0.7% or 0.006, while the NEM population experienced small but statistically significant increases in their on-peak demand by 0.7% or 0.008 kW.

Figure 5-6: Average Winter Peak Period Load Impacts for Rate 4 by NEM Status (Positive values represent load reductions)

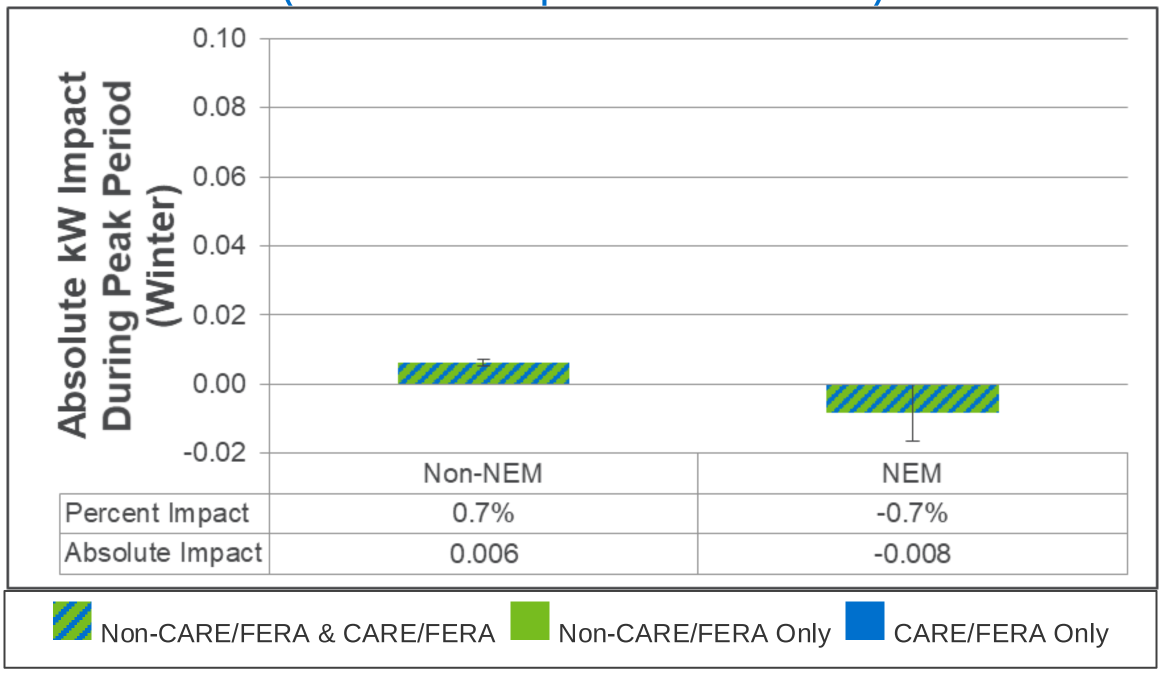
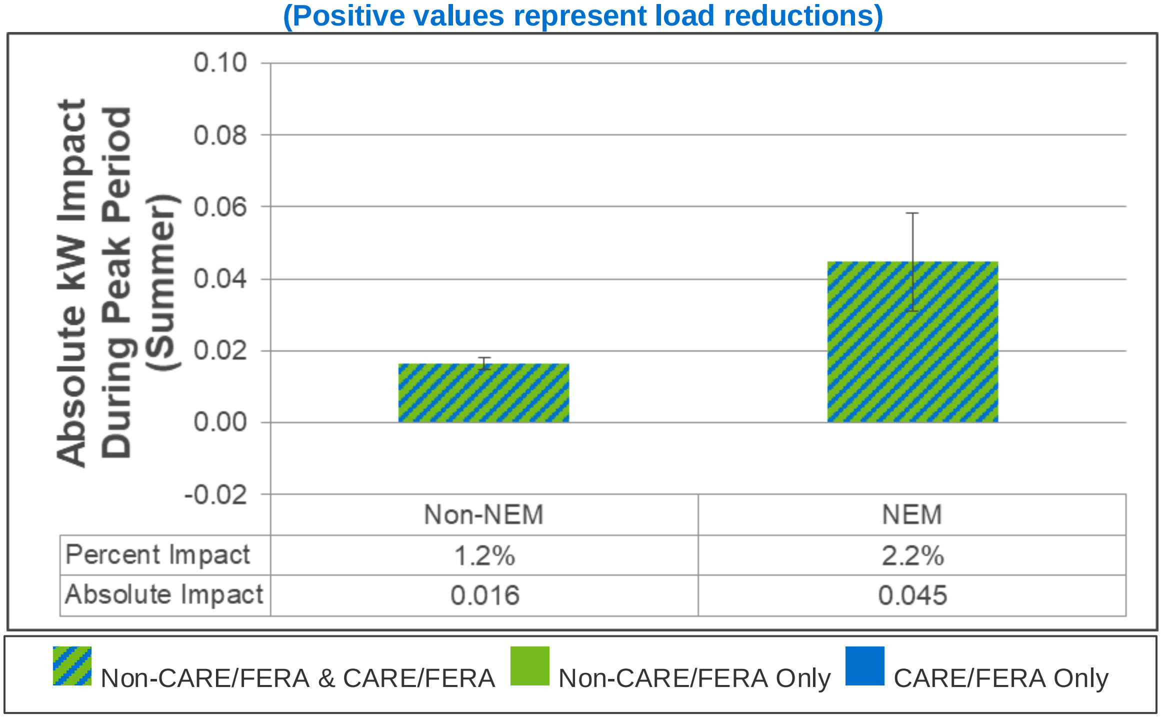


Figure 5-7 presents average summer 2020 weekday peak period load reductions for NEM and non-NEM customers. NEM customers had load impacts equal to 2.2% or 0.045 kW which is statistically significantly larger (in percentage and absolute terms) than non-NEM customers during the same time period (1.2% or 0.016 kW).

Figure 5-7: Average Summer Peak Period Load Impacts for Rate 4 by NEM Status (Positive values represent load reductions)



5.3 Rate 5

5.3.1 Load Impacts by Pilot Segment

Figure 5-8 shows the peak period load reductions on average winter 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, 0.9% or 0.008 kW, were larger than those for Rate 4 (0.6% or 0.006 kW). Load impacts were greatest in Climate Zone 10 (1.2% or 0.012 kW) and lowest in the moderate climate region (0.8% or 0.007 kW). The impacts in the hot climate region and Climate Zone 10 were not significantly different from each other (in both absolute and percentage terms) and the moderate and cool climate regions are not significantly different from each other (also in both absolute and percentage terms).

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

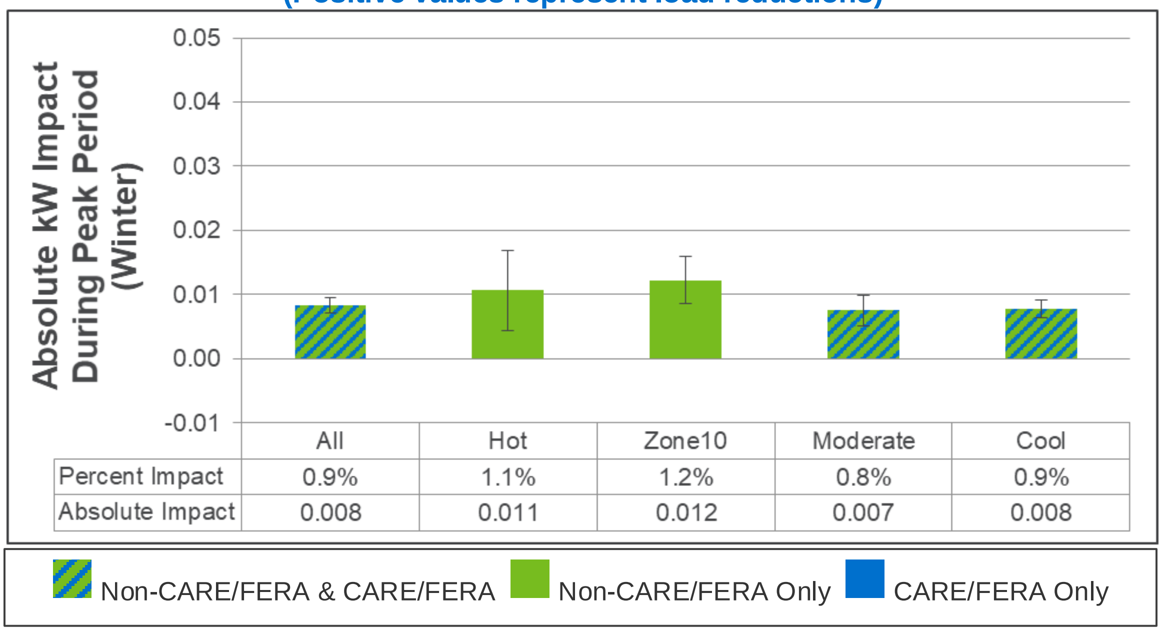
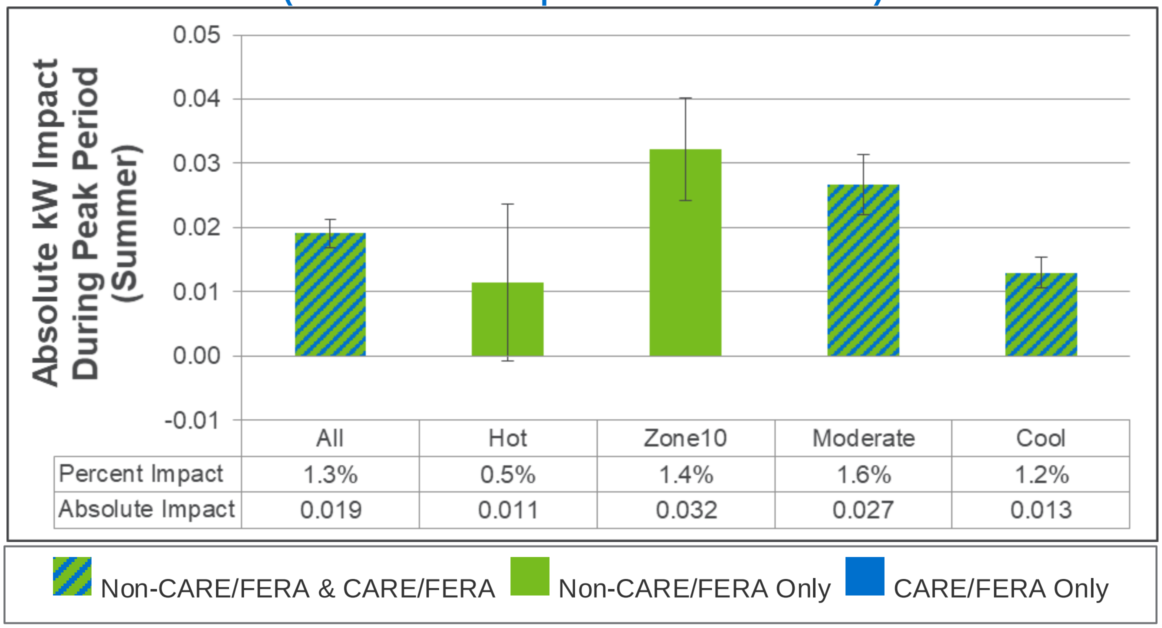


Figure 5-9 shows the peak period load reductions on average summer weekdays for Rate 5. All load reductions with the exception of the hot climate region were statistically significant at the 90% confidence level. In the summer period, the load reductions for Rate 5 for the SCE territory as a whole, 1.3% or 0.019 kW, were larger than those for Rate 4 (1.1% or 0.016 kW). Percent load impacts were greatest in the moderate climate region (1.6% or 0.027 kW) and lowest in the hot climate region (0.5% or 0.011 kW). Climate Zone 10 had the largest absolute impact of 0.032 kW. Load impacts in the moderate climate region and Climate Zone 10 are not significantly different from each other (in both percentage and absolute terms). Load impacts in the cool climate region were significantly smaller than the moderate climate region and Climate Zone 10 (in absolute terms). Load impacts in the hot climate region were not statistically significantly greater from zero.

Figure 5-9: Average Summer Peak Period Load Impacts for Rate 5 by Climate Region (Positive values represent load reductions)



5.3.2 Load Impacts by LCA

Figure 5-10 shows the winter peak period load impacts for Rate 5 for each LCA. Peak period load impacts were largest in the Ventura/Big Creek LCA with impacts equal to 1.4% or 0.014 kW, and the difference in load impacts between the Ventura/Big Creek LCA and the other two LCAs is statistically significant (in both percentage and absolute terms). The difference between the LA Basin and the Outside LA Basin LCAs is not statistically significant in absolute or percentage terms.

Figure 5-10: Average Winter Peak Period Load Impacts for Rate 5 by LCA (Positive values represent load reductions)

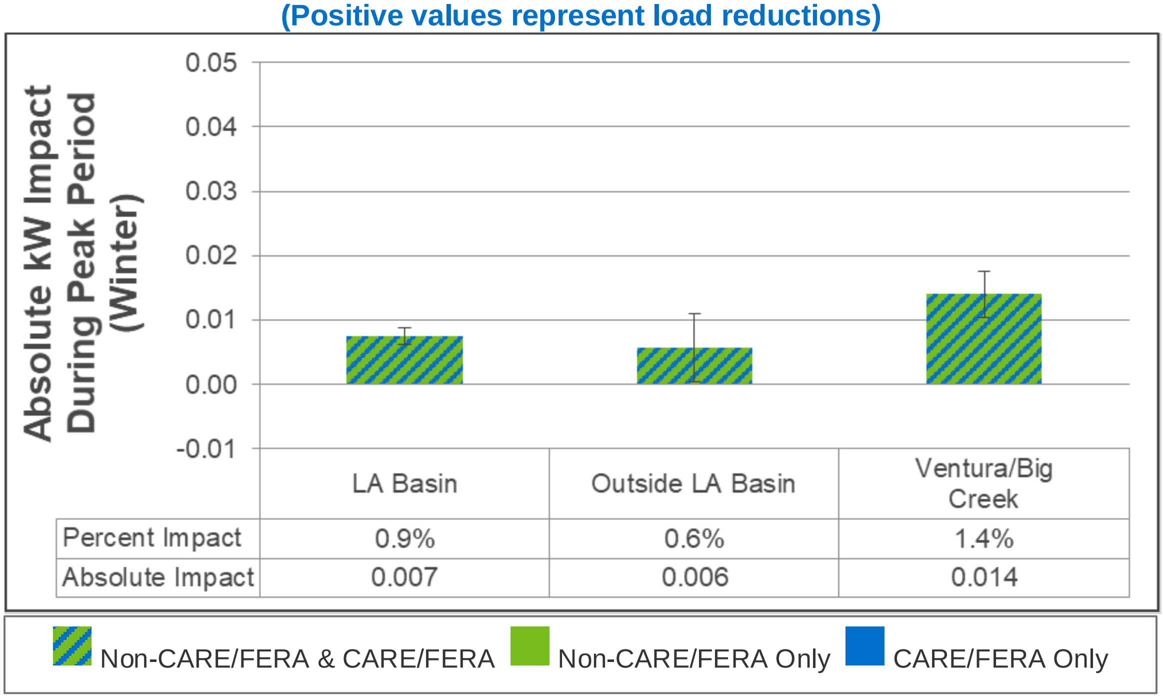
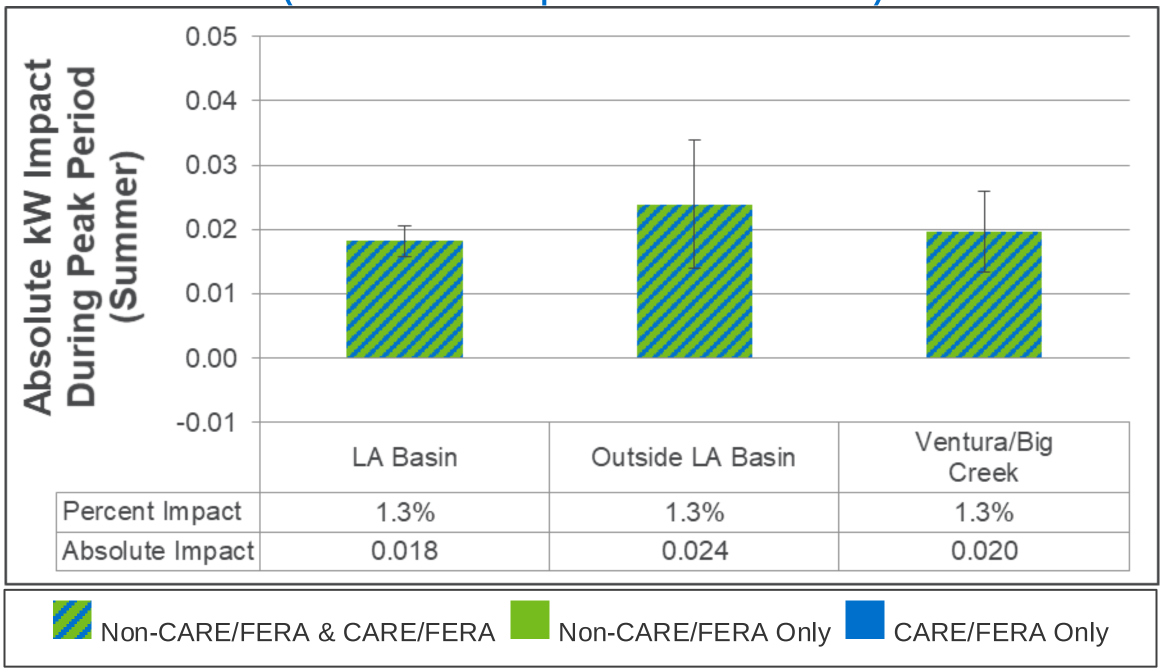


Figure 5-11 presents the absolute and percent summer peak period load impacts for Rate 5 for each LCA. Peak period load impacts were similar across the three LCAs (1.3%). The Outside LA Basin LCA had the largest absolute impacts of 0.024 kW, however the load impacts across the three LCAs are not statistically significantly different (in neither percentage nor absolute impact terms).

Figure 5-11: Average Summer Peak Period Load Impacts of Rate 5 by LCA (Positive values represent load reductions)



	LA Basin	Outside LA Basin	Ventura/Big Creek
Percent Impact	1.3%	1.3%	1.3%
Absolute Impact	0.018	0.024	0.020

5.3.3 Load Impacts by NEM and Non-NEM

Figure 5-12 presents average winter weekday peak period load reductions for non-NEM and NEM customers. Similar to Rate 4, there is a large difference in load impacts between the two populations. NEM customers on Rate 5 reduced peak demand by 3.3% or 0.044 kW, while non-NEM impacts were equal to 0.8% and 0.007 kW. This difference is statistically significant in absolute and percentage terms.

Figure 5-12: Average Winter Peak Period Load Impacts for Rate 5 by NEM Status (Positive values represent load reductions)

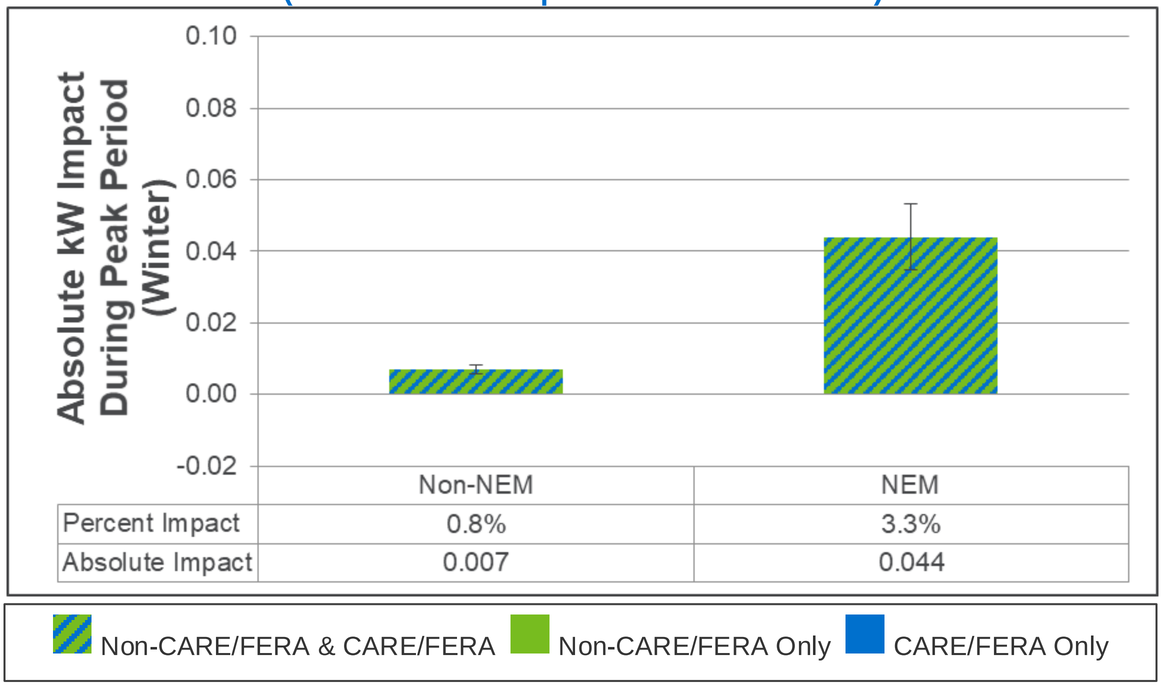
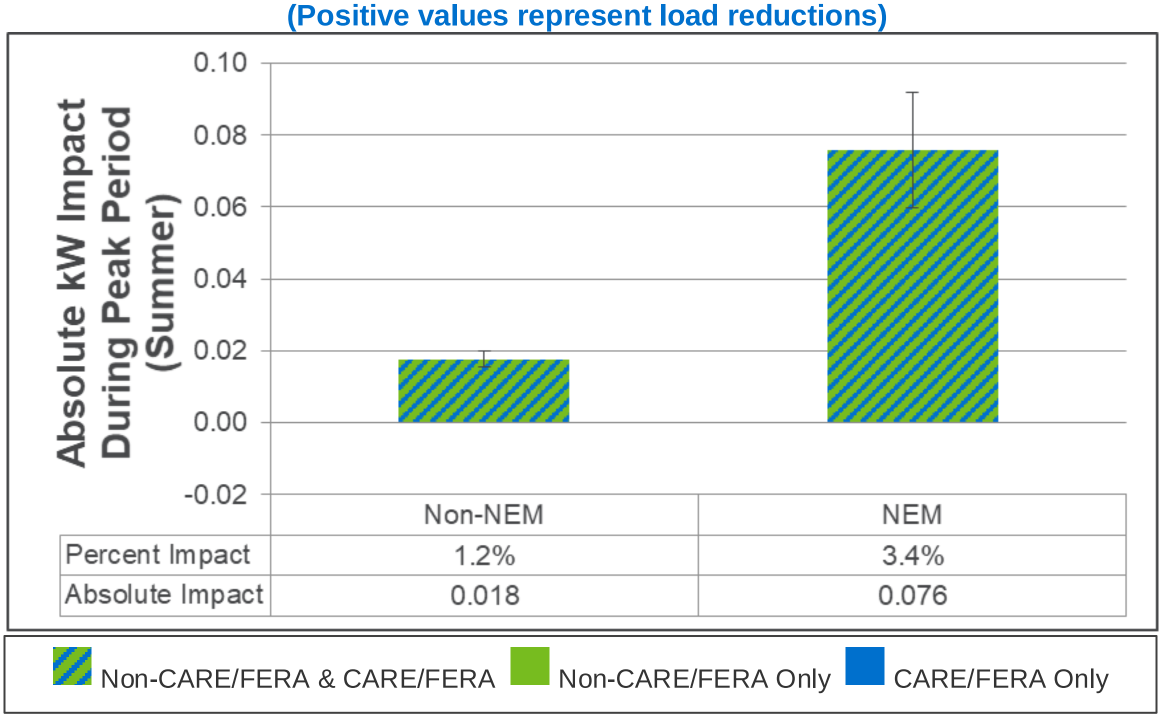


Figure 5-13 shows average summer weekday peak period load reductions for non-NEM and NEM customers. Again, there is a large difference in load impacts between the two populations. NEM customers on Rate 5 reduced demand by 3.4% or 0.076 kW during the summer months, while non-NEM load impacts were equal to 1.2% and 0.018 kW. This difference is statistically significant in absolute and percentage terms.

Figure 5-13: Average Summer Peak Period Load Impacts for Rate 5 by NEM Status (Positive values represent load reductions)

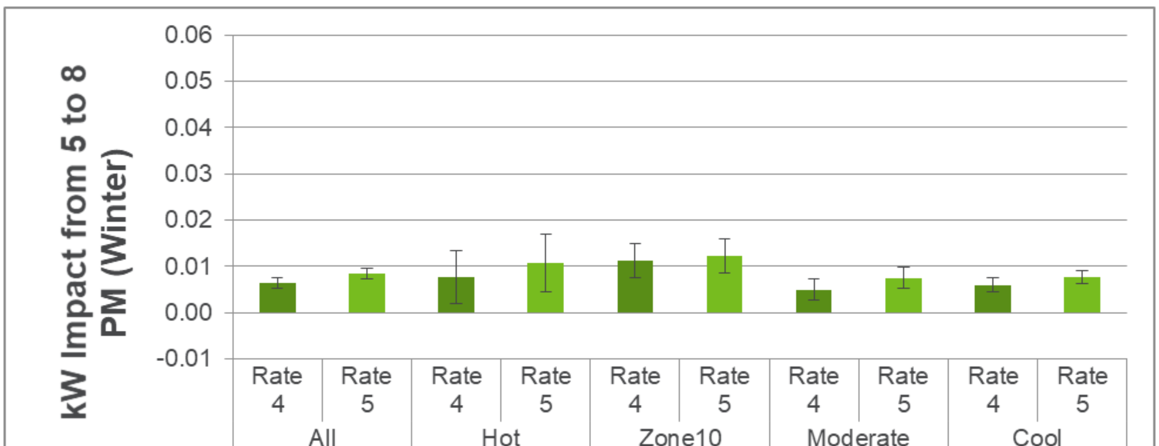


5.4 Comparison across Rates

Figure 5-14 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 winter period from October 2019 through May 2020. 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 three rate periods in winter. 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 statistically significantly larger average load reductions for the pilot as a whole than Rate 4 customers (in both percentage and absolute terms), but there were no statistically significant differences between rates in any of the individual climate regions. The largest difference was in the moderate climate region, where Rate 5 customers had percent load reductions that were 40% larger than those provided by Rate 4 customers, although the difference was not statistically significant.

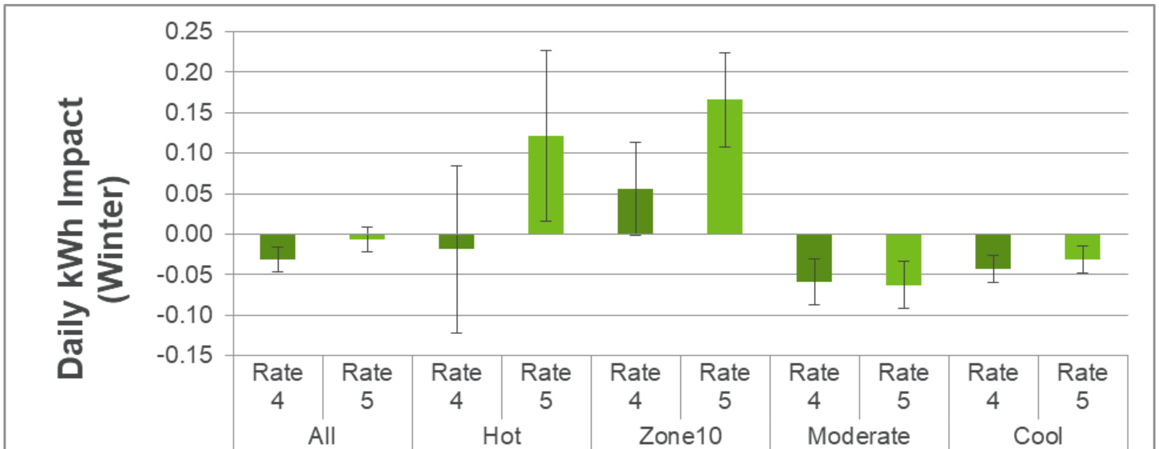
Figure 5-14: Winter Average Load Impacts from 5 PM to 8 PM across Rates



	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	0.7%	0.9%	0.8%	1.1%	1.1%	1.2%	0.5%	0.8%	0.7%	0.9%
Absolute Impact	0.006	0.008	0.008	0.011	0.011	0.012	0.005	0.007	0.006	0.008

Figure 5-15 presents the average daily kWh impacts for each rate during the winter 2019/2020 period (October 2019 through May 2020). Customers on Rate 4 increased their winter daily consumption by 0.2%, or 0.03 kWh per day (this finding is statistically significant). Customers on Rate 5, however, did not alter their daily consumption by a statistically significant amount. A key driver in the difference between the rates is the difference in daily kWh impacts between the rates in the warmer regions (the hot climate region and Climate Zone 10). Customers on Rate 5 reduced their daily consumption in both areas (0.8% in the hot climate region and 1.0% in Climate Zone 10, both statistically significant). Customers on Rate 4, on the other hand, did not have statistically significant daily impacts. In the moderate and cool climate regions, daily load increases were very similar between the two rates.

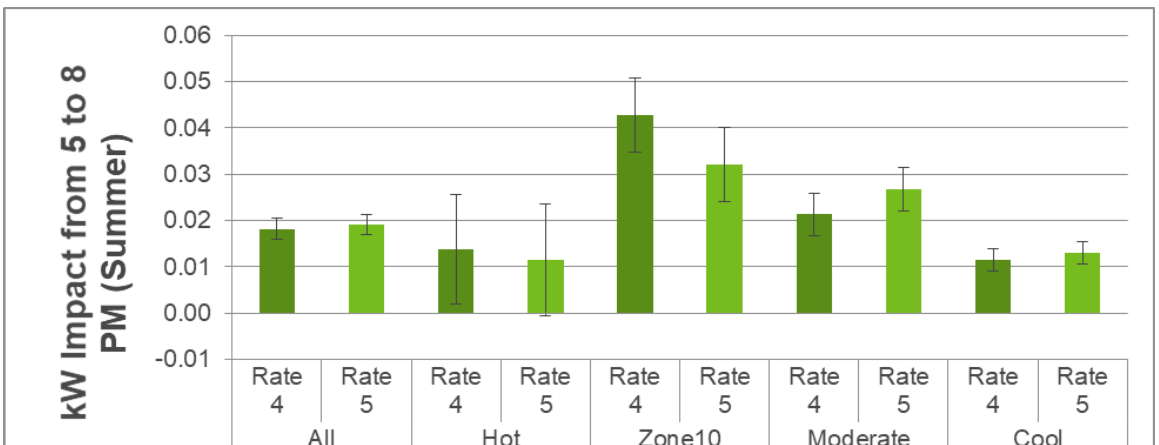
Figure 5-15: Winter Average Daily kWh Impacts across Rates



	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	-0.2%	0.0%	-0.1%	0.8%	0.3%	1.0%	-0.4%	-0.4%	-0.3%	-0.2%
Absolute Impact	-0.03	-0.01	-0.02	0.12	0.06	0.17	-0.06	-0.06	-0.04	-0.03

Figure 5-16 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 2020. Demand reductions for this time period were nearly identical between the two rates: 1.2% or 0.018 kW for Rate 4 and 1.3% or 0.019 kW for Rate 5. The difference between the two rates was not statistically significant for the service territory as a whole nor within each climate region.

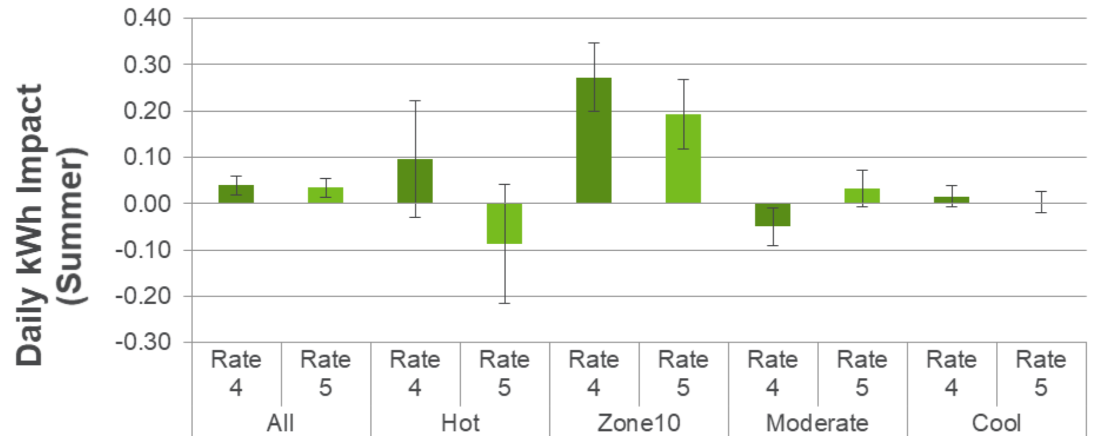
Figure 5-16: Summer Average Load Impacts from 5 PM to 8 PM across Rates



	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	1.2%	1.3%	0.7%	0.5%	1.9%	1.4%	1.3%	1.6%	1.0%	1.2%
Absolute Impact	0.018	0.019	0.014	0.011	0.043	0.032	0.021	0.027	0.012	0.013

Figure 5-17 presents the average daily kWh impacts for each rate during the summer period from June to September 2020. For the pilot populations as a whole, daily load reductions were statistically significant and very similar between Rate 4 and Rate 5 customers. Customers in Climate Zone 10 had the greatest daily kWh reductions, equal to 0.9% or 0.27 kWh for Rate 4 and 0.6% or 0.019 kWh for Rate 5 (the difference between the two rates is not statistically significant). In the hot and cool climate regions, customers did not exhibit statistically significant changes in daily energy consumption for either rate.

Figure 5-17: Summer 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	0.2%	0.2%	0.3%	-0.3%	0.9%	0.6%	-0.2%	0.1%	0.1%	0.0%
Absolute Impact	0.04	0.03	0.10	-0.09	0.27	0.19	-0.05	0.03	0.02	0.00

6 Persistence of Load Impacts

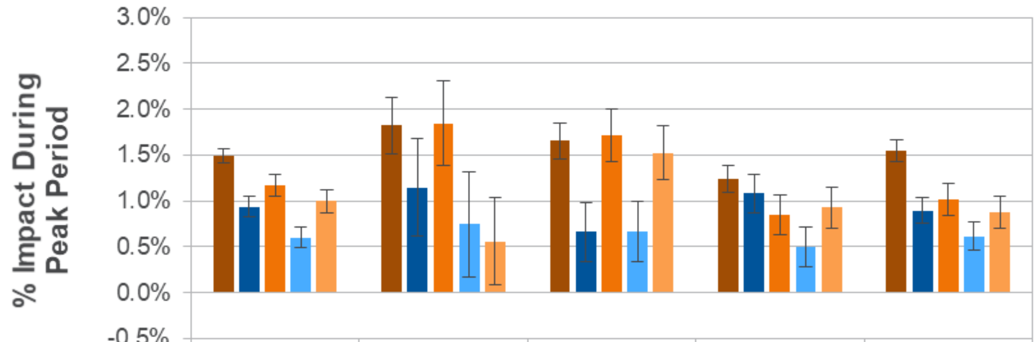
The impacts in this section represent customers who were active SCE customers until the end of September 2020, which includes three summer seasons and two winter seasons. Using this method, it is possible to compare impacts between seasons for a single group of customers, rather than a changing population. 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. Many factors may contribute to year-over-year differences in load impacts, including changes in weather, economic conditions, and the effects of the COVID-19 pandemic in 2020.

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 2020). All five 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 generally smaller in the two winter seasons than in the summer seasons. One exception was the moderate climate region, in which summer 2019 impacts were smaller than those in winter 2018/2019 (however the difference was not statistically significant). Across the three summers, load impacts decreased slightly for the Rate 4 population as a whole from 1.5% in 2018 to 1.0% in summer 2020. Load impacts in the second and third summers are statistically significantly smaller than load impacts in the first summer, but the difference between the second and third summer is not statistically significant. The hot climate region had the largest change in load impacts from summer 2019 to summer 2020: impacts fell from 1.8% to 0.6%, a drop of about 67%. The other climate regions did not have significant load impact decreases across the summer seasons.

The Rate 4 population had statistically significant load impact reductions between the two winter seasons, with load impacts falling from 0.9% to 0.6% from winter 2018/2019 to winter 2019/2020. It is important to note, however, that the second winter includes the beginning of the COVID-19 pandemic. Winter load impacts decreased by statistically significant amounts in the moderate and cool climate regions. There were no statistically significant differences across winters in the hot climate region and Climate Zone 10.

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



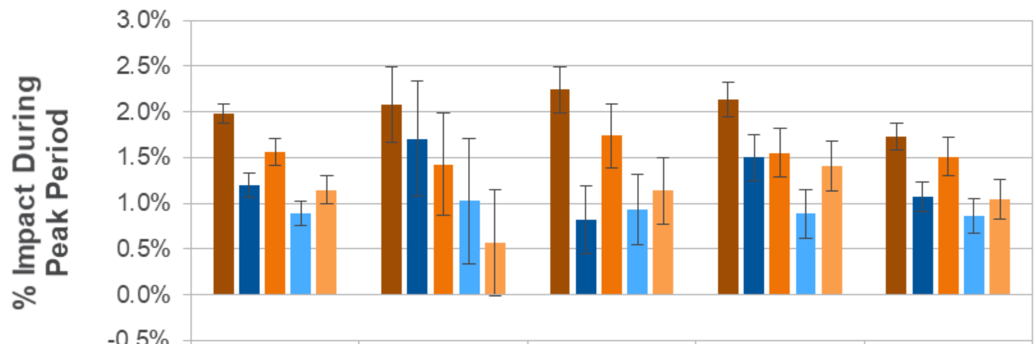
	All	Hot	Zone10	Moderate	Cool
Summer - 2018	1.5%	1.8%	1.7%	1.2%	1.5%
Winter - 2018/2019	0.9%	1.1%	0.7%	1.1%	0.9%
Summer - 2019	1.2%	1.8%	1.7%	0.8%	1.0%
Winter - 2019/2020	0.6%	0.7%	0.7%	0.5%	0.6%
Summer - 2020	1.0%	0.6%	1.5%	0.9%	0.9%

6.2 Rate 5

Figure 6-2 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 third summer of the pilot. For each climate zone and the SCE territory as a whole, impacts were greatest during the first summer of the pilot (June through September 2018). For the service territory as a whole and for each climate region, load impacts were smaller in the two winter seasons than in the three summer seasons. One exception was the hot climate region, in which summer 2020 impacts were smaller than those in winter 2019/2020, however the difference was not statistically significant. There were statistically significant decreases in load impacts for the service territory as a whole from 2018 to 2019, and from 2019 to 2020. At the climate region level, only the cool climate region had statistically significantly smaller load impacts from summer 2019 to summer 2020.

Rate 5 winter load impacts for the service territory as a whole were statistically significantly smaller in 2019/2020 (versus 2018/2019). The moderate climate region is the only region with significantly smaller load impacts in the second winter versus the first winter.

Figure 6-2: Percent Impacts for Peak Period for Rate 5, by Season (Positive values represent load reductions)



	All	Hot	Zone10	Moderate	Cool
Summer - 2018	2.0%	2.1%	2.2%	2.1%	1.7%
Winter - 2018/2019	1.2%	1.7%	0.8%	1.5%	1.1%
Summer - 2019	1.6%	1.4%	1.7%	1.6%	1.5%
Winter - 2019/2020	0.9%	1.0%	0.9%	0.9%	0.9%
Summer - 2020	1.1%	0.6%	1.1%	1.4%	1.0%

6.3 Comparison of 2018, 2019, and 2020 Weather

Several factors contribute to differences in load impacts from year to year, and a key driver is weather and the effect of the COVID-19 pandemic on residential energy consumption and their ability or motivation to respond to TOU rates. Figure 6-3 presents Rate 4 average weekday peak period impacts and temperatures for the summer periods in 2018, 2019, and 2020. Figure 6-4 presents the same information for Rate 5. The following figures illustrate that on average, temperatures were warmest in 2018 (and were similar between 2019 and 2020). For temperatures over 80 degrees Fahrenheit, Rate 4 impacts were slightly smaller in 2020 than they were in 2019. The inverse was true at temperatures below 80 degress. As indicated in Figure 6-1, summer peak period impacts were greatest in 2018. This is true at most temperatures, as indicated by the green trendline in Figure 6-3.

For Rate 5, 2020 peak period impacts were lower than those in both 2018 and 2019 at all peak period summer temperatures (the orange trendline is lower than the blue and green trendlines). For both rates, it is possible that the COVID-19 pandemic had an effect on customers' abilities to shift consumption because of changing work schedules or home occupancy levels throughout the day.

Figure 6-3: Comparison of Summer Average Weekday Peak Period Temperatures and Impacts – Rate 4

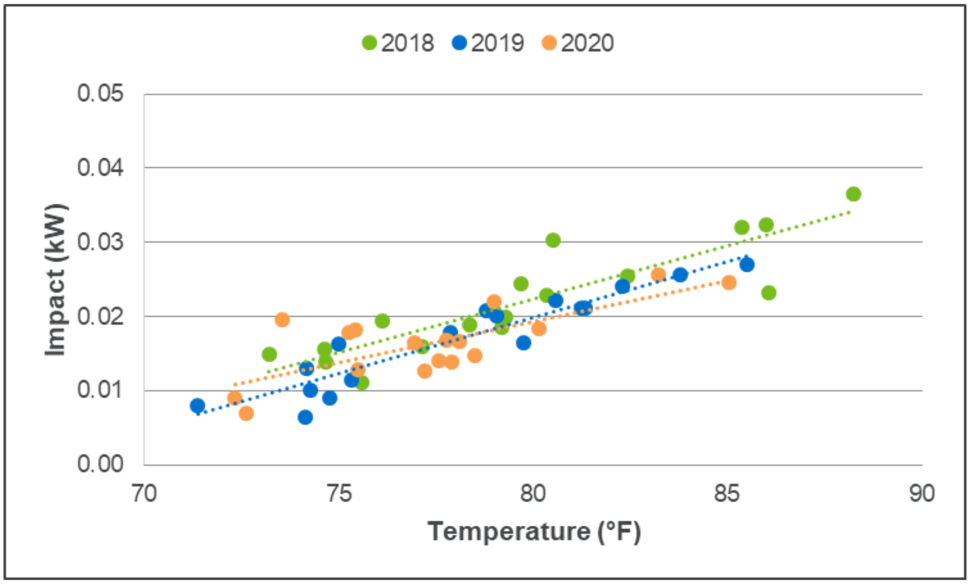
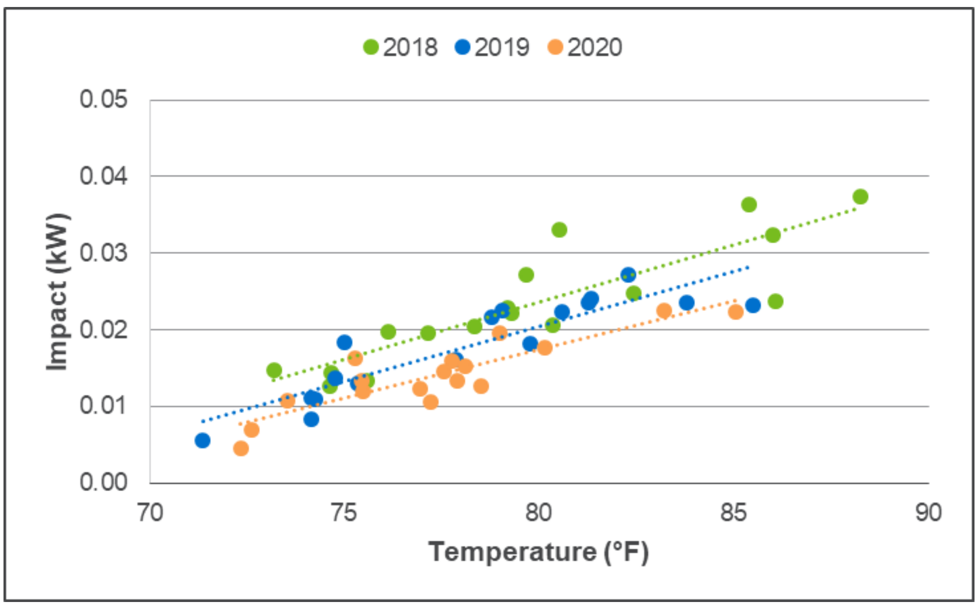


Figure 6-4: Comparison of Summer Average Weekday Peak Period Temperatures and Impacts – Rate 5



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-in-10 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, weekly ex post load impacts from March 2018 through September 2020 were developed using the fixed effects regression methodology described in Section 3.1;
- Next, the relationship between ex post load impacts and weather is estimated for each hour of the day, each season (summer/winter) and each customer segment and rate; [22]
- 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.

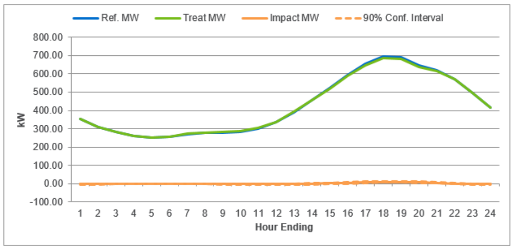
A similar method was used to estimate reference loads, which are needed to meet this evaluation's reporting requirements. Underlying the values presented in this section are electronic tables that contain estimates for each hour of the day for each day type, segment, month, and forecast year from 2021 through 2031. 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.

[22] Months where COVID-19 stay-at-home orders were in effect are accounted for in the model.

Figure 7-1: Example of Content of Electronic Tables Underlying Load Impacts Summarized in this Report (SCE Rate 4, Average August 2021 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:	2021
Segment:	All
Rate:	Rate 4
Enrollment:	475,506

Period	Weighted Temp. (°F)	Ref. MW	Treat MW	Impact MW	90% Conf. Interval		% Impact
Peak	79.4	661.07	652.61	8.46	6.74	10.18	1.3%
Mid-Peak	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Off-Peak	70.7	363.58	364.22	-0.64	-1.32	0.05	-0.2%
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**	**661.07**	**652.61**	**8.46**	**5.47**	**7.24**	**1.3%**
Day (kWh)	**72.5**	**10,213.35**	**10,183.13**	**30.22**	**14.66**	**45.79**	**0.3%**



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	354.03	355.40	-1.37	-0.4%	67.7	-3.31	-2.16	-1.37	-0.57	0.58
2	Off-Peak	309.76	310.91	-1.15	-0.4%	66.9	-2.74	-1.80	-1.15	-0.50	0.43
3	Off-Peak	280.83	281.30	-0.47	-0.2%	66.2	-1.83	-1.03	-0.47	0.08	0.88
4	Off-Peak	262.27	262.76	-0.50	-0.2%	65.5	-1.80	-1.03	-0.50	0.03	0.80
5	Off-Peak	253.57	254.03	-0.46	-0.2%	64.9	-1.63	-0.94	-0.46	0.02	0.71
6	Off-Peak	256.75	257.62	-0.87	-0.3%	64.5	-2.27	-1.44	-0.87	-0.30	0.53
7	Off-Peak	271.14	272.32	-1.18	-0.4%	64.1	-2.49	-1.72	-1.18	-0.65	0.12
8	Off-Peak	279.08	279.26	-0.18	-0.1%	64.2	-1.53	-0.74	-0.18	0.37	1.16
9	Off-Peak	280.37	281.79	-1.42	-0.5%	66.1	-3.08	-2.10	-1.42	-0.74	0.24
10	Off-Peak	284.75	287.10	-2.35	-0.8%	69.1	-4.54	-3.24	-2.35	-1.45	-0.15
11	Off-Peak	300.62	302.93	-2.31	-0.8%	72.7	-4.81	-3.33	-2.31	-1.29	0.18
12	Off-Peak	335.79	338.00	-2.21	-0.7%	76.1	-4.59	-3.18	-2.21	-1.23	0.17
13	Off-Peak	390.42	391.68	-1.26	-0.3%	78.8	-4.03	-2.39	-1.26	-0.13	1.51
14	Off-Peak	453.95	454.37	-0.42	-0.1%	80.9	-3.76	-1.79	-0.42	0.95	2.93
15	Off-Peak	520.86	518.87	1.98	0.4%	82.2	-1.76	0.45	1.98	3.51	5.72
16	Off-Peak	592.98	588.31	4.66	0.8%	82.7	1.16	3.23	4.66	6.10	8.17
17	Peak	653.76	645.61	8.15	1.2%	82.7	4.75	6.76	8.15	9.54	11.55
18	Peak	694.06	684.62	9.44	1.4%	81.9	6.57	8.26	9.44	10.61	12.30
19	Peak	690.16	679.82	10.35	1.5%	80.3	7.33	9.11	10.35	11.58	13.36
20	Peak	645.98	637.29	8.69	1.3%	77.9	5.95	7.57	8.69	9.81	11.42
21	Peak	621.37	615.70	5.67	0.9%	74.3	2.75	4.48	5.67	6.87	8.60
22	Off-Peak	570.04	568.98	1.06	0.2%	71.5	-1.53	0.00	1.06	2.12	3.65
23	Off-Peak	494.71	496.64	-1.93	-0.4%	69.8	-4.71	-3.07	-1.93	-0.79	0.85
24	Off-Peak	416.10	417.79	-1.69	-0.4%	68.7	-4.22	-2.72	-1.69	-0.65	0.85

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 2021 through 2031. Enrollments onto Rate 4 and Rate 5 are expected to grow through a series of waves of default enrollment in late 2021 and early 2022. Approximately 1.8 million customers will be enrolled onto the rates through default, after adjusting for a pre-enrollment opt-out rate of 22%, based on historical data. Customers will be defaulted onto the best rate for them (that is, the rate that will result in the lowest bills). It is estimated that 44% will be defaulted onto Rate 4, and the remainder will be defaulted onto Rate 5. Approximately 20,000 Rate 4 and 1,600 Rate 5 customers will join the rates each month as they turn on new accounts with SCE. An attrition rate of 1% is assumed across all months of the enrollment forecast and as a result, enrollment in Rate 4 is projected to steadily increase to almost 1.8 million by January 2031 and enrollment in Rate 5 is expected to decrease following the default period (as attrition will outweigh new enrollments).

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

Forecast Year	Rate 4				Rate 5			
	LA Basin	Outside LA Basin	Ventura/ Big Creek	Total	LA Basin	Outside LA Basin	Ventura/ Big Creek	Total
2021	291,777	21,883	51,061	**364,721**	183,636	13,773	32,136	**229,545**
2022	841,746	63,131	147,306	**1,052,182**	688,975	51,673	120,571	**861,218**
2023	1,141,028	85,577	199,680	**1,426,285**	897,544	67,316	157,070	**1,121,930**
2024	1,191,973	89,398	208,595	**1,489,966**	809,781	60,734	141,712	**1,012,227**
2025	1,237,084	92,781	216,490	**1,546,356**	732,069	54,905	128,112	**915,086**
2026	1,277,030	95,777	223,480	**1,596,288**	663,255	49,744	116,070	**829,069**
2027	1,312,402	98,430	229,670	**1,640,502**	602,321	45,174	105,406	**752,901**
2028	1,343,723	100,779	235,151	**1,679,653**	548,364	41,127	95,964	**685,456**
2029	1,371,457	102,859	240,005	**1,714,321**	500,587	37,544	87,603	**625,733**
2030	1,396,016	104,701	244,303	**1,745,020**	458,280	34,371	80,199	**572,850**
2031	1,417,762	106,332	248,108	**1,772,203**	420,818	31,561	73,643	**526,022**

7.2 Rate 4

Table 7-2 presents per customer ex ante load reduction estimates for the average 2021 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. It should be noted that 2021 estimates are based on a COVID-19 indicator of 0.5, forecasting that the pandemic will have half the impact on electric demand that it did from March to December 2020.

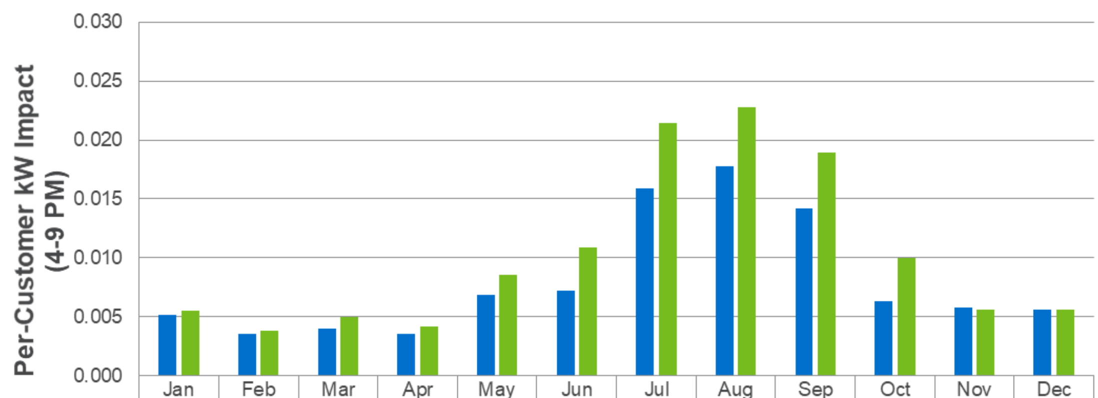
The greatest load impacts for 1-in-2 SCE weather conditions occur in July, August, and September and are expected to range from about 0.014 kW in September to 0.018 kW in August. The greatest impacts under 1-in-2 CAISO conditions are also in these months and are nearly identical to the impacts under the SCE weather conditions. The greatest impacts under the 1-in-10 weather scenarios also occur in July, August, and September and are about 0.02 kW. SCE peaking conditions are slightly warmer than CAISO peaking conditions in a 1-in-10 weather year, and as a result the impacts under SCE peaking conditions are expected to be slightly higher.

Table 7-2: Average 2021 Weekday Ex Ante Impact Estimates Per Customer – Rate 4

Weather Year	Month	SCE		CAISO	
		Impact (kW)	Temperature (°F)	Impact (kW)	Temperature (°F)
1-in-2	January	0.005	62.4	0.005	61.6
	February	0.004	60.7	0.004	61.8
	March	0.004	63.3	0.004	63.4
	April	0.004	65.8	0.004	66.0
	May	0.007	68.2	0.007	68.2
	June	0.007	73.9	0.007	73.9
	July	0.016	78.1	0.016	78.1
	August	0.018	79.4	0.018	79.4
	September	0.014	76.8	0.014	77.2
	October	0.006	71.5	0.006	71.5
	November	0.006	64.9	0.005	63.6
	December	0.006	57.4	0.006	56.5
1-in-10	January	0.006	56.9	0.006	56.9
	February	0.004	64.3	0.004	57.6
	March	0.005	69.5	0.005	69.5
	April	0.004	69.7	0.004	69.5
	May	0.009	73.4	0.009	73.4
	June	0.011	76.5	0.011	76.5
	July	0.021	82.5	0.021	82.5
	August	0.023	82.1	0.021	81.2
	September	0.019	80.5	0.019	80.5
	October	0.010	76.8	0.010	76.8
	November	0.006	65.9	0.006	65.9
	December	0.006	57.3	0.006	58.9

Figure 7-2 presents the average 2021 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 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 2021 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	0.005	0.004	0.004	0.004	0.007	0.007	0.016	0.018	0.014	0.006	0.006	0.006
SCE 1-in-10	0.006	0.004	0.005	0.004	0.009	0.011	0.021	0.023	0.019	0.010	0.006	0.006

Table 7-3 presents Rate 4 per customer ex ante load reduction estimates for the average 2028 to 2031 weekday under CAISO and SCE conditions. For the years 2028 through 2031, the COVID-19 indicator is zero – meaning the pandemic is expected to have little to no effect on customer demand and TOU load impacts. Predicted per-customer impacts are about 10% to 20% higher than the 2021 forecast year as the effects of the pandemic are expected to decline to zero. The greatest impacts for 1-in-2 SCE weather conditions still occur in July, August, and September and are expected to reach about 0.020 kW in those months. The greatest impacts under 1-in-2 CAISO conditions are also in these months and are nearly identical to the impacts under the SCE weather conditions. The greatest impacts under the 1-in-10 weather scenarios also occur in July, August, and September and reach 0.025 kW in August.

Table 7-3: Average 2028-2031 Weekday Ex Ante Impact Estimates Per Customer – Rate 4

Weather Year	Month	SCE		CAISO	
		Impact (kW)	Temperature (°F)	Impact (kW)	Temperature (°F)
1-in-2	January	0.006	62.4	0.006	61.6
	February	0.005	60.7	0.005	61.8
	March	0.005	63.3	0.005	63.4
	April	0.005	65.8	0.005	66.0
	May	0.008	68.2	0.008	68.2
	June	0.010	73.9	0.010	73.9
	July	0.018	78.1	0.018	78.1
	August	0.020	79.4	0.020	79.4
	September	0.017	76.8	0.017	77.2
	October	0.007	71.5	0.007	71.5
	November	0.007	64.9	0.007	63.6
	December	0.007	57.4	0.007	56.5
1-in-10	January	0.007	56.9	0.007	56.9
	February	0.005	64.3	0.005	57.6
	March	0.006	69.5	0.006	69.5
	April	0.005	69.7	0.005	69.5
	May	0.010	73.4	0.010	73.4
	June	0.013	76.5	0.013	76.5
	July	0.024	82.5	0.024	82.5
	August	0.025	82.1	0.024	81.2
	September	0.021	80.5	0.021	80.5
	October	0.011	76.8	0.011	76.8
	November	0.007	65.9	0.007	65.9
	December	0.007	57.3	0.007	58.9

Figure 7-3 presents the average weekday impacts during the RA window under 1-in-2 and 1-in-10 SCE weather conditions for the years 2028 through 2031. The 1-in-10 weather scenario is expected to have similar or larger impacts than the 1-in-2 scenario in all months. This is much like 2021 forecast year, with the difference in impacts being smallest in winter and shoulder months and largest in the summer months.

Figure 7-3: Average 2028-2031 Weekday Ex Ante Impact Estimates – SCE Weather, Rate 4

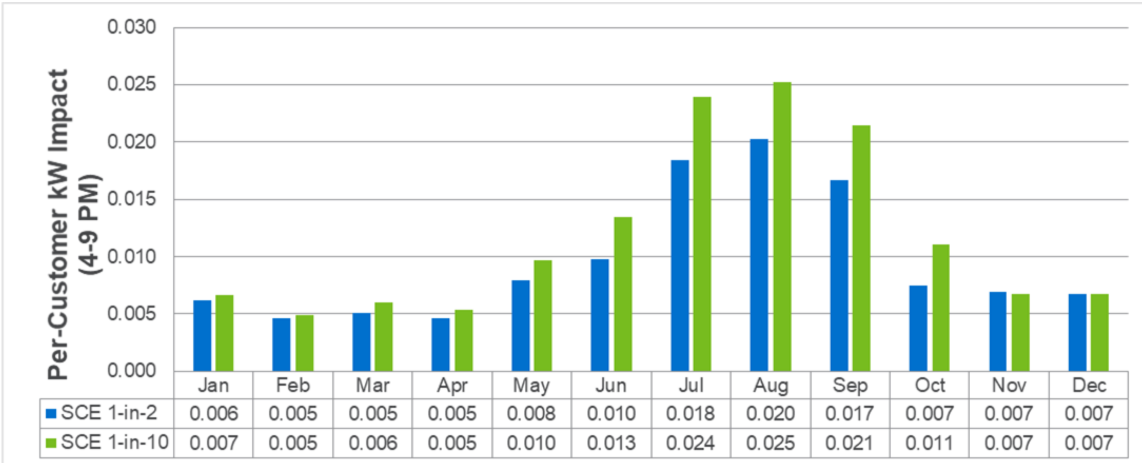


Table 7-4 summarizes the aggregate average weekday Rate 4 ex ante load impact estimates for each month and year of the forecast. The impacts presented in this table are in MW. As described previously, impacts are expected to be greatest in the summer months. The largest expected load impact of 45.1 MW occurs in August 2031 under 1-in-10 conditions, when the ex ante weather is warmest and when Rate 4 enrollment is expected to be near its highest. Aggregate impacts are expected to be smallest in February and April in 2021, before the large default waves expand the number of customers on Rate 4.

Table 7-4: Aggregate Average Weekday MW Ex Ante Load Impacts during RA Window 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	2021	1.9	1.3	1.6	1.4	2.9	3.2	7.3	8.5	6.9	3.9	4.5	4.9
	2022	6.0	4.9	6.2	5.6	10.2	11.8	23.9	26.6	21.6	9.7	9.0	8.7
	2023	8.5	6.3	6.9	6.3	11.1	13.2	25.9	28.8	23.5	10.6	9.8	9.5
	2024	9.1	6.8	7.4	6.8	11.8	14.3	27.5	30.5	25.0	11.2	10.4	10.2
	2025	9.5	7.1	7.8	7.1	12.3	15.0	28.7	31.8	26.1	11.7	10.9	10.6
	2026	9.9	7.4	8.1	7.4	12.7	15.6	29.7	32.8	26.9	12.1	11.2	10.9
	2027	10.2	7.6	8.4	7.6	13.1	16.1	30.5	33.7	27.7	12.4	11.5	11.2
	2028	10.5	7.8	8.6	7.8	13.4	16.5	31.3	34.5	28.4	12.7	11.8	11.5
	2029	10.7	8.0	8.8	8.0	13.7	16.8	31.9	35.2	28.9	13.0	12.0	11.7
	2030	10.9	8.1	8.9	8.1	13.9	17.1	32.4	35.8	29.4	13.2	12.2	11.9
	2031	11.0	8.3	9.1	8.2	14.1	17.4	32.9	36.3	29.8	13.4	12.4	12.1
SCE 1-in-10	2021	2.0	1.4	2.0	1.7	3.7	4.9	9.9	10.8	9.3	6.1	4.4	4.9
	2022	6.4	5.2	7.5	6.5	12.6	16.9	31.6	33.5	28.3	14.8	8.7	8.7
	2023	9.1	6.6	8.3	7.3	13.6	18.6	34.0	36.0	30.6	15.9	9.5	9.5
	2024	9.7	7.2	8.9	7.8	14.4	19.9	35.9	38.0	32.3	16.7	10.2	10.1
	2025	10.2	7.5	9.3	8.2	15.1	20.8	37.4	39.6	33.7	17.4	10.6	10.6
	2026	10.6	7.8	9.6	8.5	15.5	21.5	38.6	40.8	34.7	18.0	10.9	10.9
	2027	10.9	8.1	9.9	8.8	16.0	22.2	39.7	42.0	35.7	18.4	11.2	11.2
	2028	11.2	8.3	10.2	9.0	16.4	22.7	40.6	43.0	36.5	18.9	11.5	11.5
	2029	11.4	8.4	10.4	9.2	16.7	23.2	41.4	43.8	37.2	19.2	11.7	11.7
	2030	11.6	8.6	10.6	9.3	17.0	23.6	42.1	44.5	37.8	19.5	11.9	11.9
	2031	11.8	8.7	10.7	9.5	17.3	23.9	42.7	45.1	38.4	19.8	12.1	12.0

7.3 Rate 5

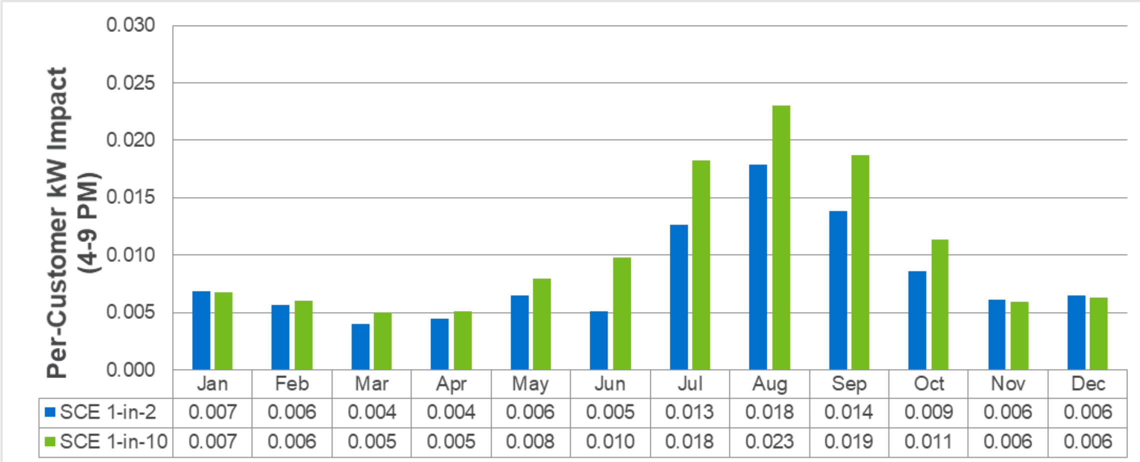
Table 7-5 summarizes the average 2021 weekday ex ante impact estimates for Rate 5 under 1-in-2 and 1-in-10 SCE and CAISO weather conditions for the RA window from 4:00 to 9:00 PM. The RA window from 4:00 to 9:00 PM includes hours from outside of the peak period for Rate 5 (5:00 to 8:00 PM). Customers are not expected to reduce their usage from 4:00 to 5:00 PM or from 8:00 to 9:00 PM. However, those hours are still included in the calculation, leading to potentially smaller impacts than presented in the ex post results section above. Per-customer impacts for the 1-in-10 weather year are expected to reach above 0.020 kW in August, with July and September impacts expected to be just below 0.020 kW. Impacts are expected to be smallest under 1-in-2 conditions in the shoulder months of March and April (0.004 kW). In 2021, Rate 5 ex ante load impacts are expected to be slightly higher than Rate 4 during the winter months, and they are about the same as Rate 4 during the summer months. Rate 5 has lower expected impacts (versus Rate 4) in July 2021 under both 1-in-2 and 1-in-10 weather conditions.

Table 7-5: Average 2021 Weekday Ex Ante Impact Estimates Per Customer– Rate 5

Weather Year	Month	SCE Impact (kW)	SCE Temperature (°F)	CAISO Impact (kW)	CAISO Temperature (°F)
1-in-2	January	0.007	62.4	0.007	61.6
	February	0.006	60.7	0.006	61.8
	March	0.004	63.3	0.004	63.4
	April	0.004	65.8	0.004	66.0
	May	0.006	68.2	0.006	68.2
	June	0.005	73.9	0.005	73.9
	July	0.013	78.1	0.013	78.1
	August	0.018	79.4	0.018	79.4
	September	0.014	76.8	0.014	77.2
	October	0.009	71.5	0.009	71.5
	November	0.006	64.9	0.006	63.6
	December	0.006	57.4	0.006	56.5
1-in-10	January	0.007	56.9	0.007	56.9
	February	0.006	64.3	0.006	57.6
	March	0.005	69.5	0.005	69.5
	April	0.005	69.7	0.005	69.5
	May	0.008	73.4	0.008	73.4
	June	0.010	76.5	0.010	76.5
	July	0.018	82.5	0.018	82.5
	August	0.023	82.1	0.021	81.2
	September	0.019	80.5	0.019	80.5
	October	0.011	76.8	0.011	76.8
	November	0.006	65.9	0.006	65.9
	December	0.006	57.3	0.007	58.9

Figure 7-4 presents the average 2021 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.

Figure 7-4: Average 2021 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	0.007	0.006	0.004	0.004	0.006	0.005	0.013	0.018	0.014	0.009	0.006	0.006
SCE 1-in-10	0.007	0.006	0.005	0.005	0.008	0.010	0.018	0.023	0.019	0.011	0.006	0.006

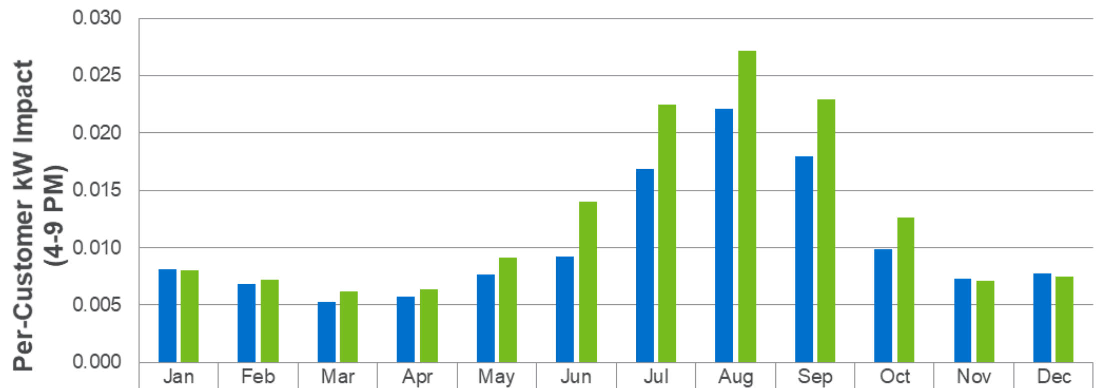
Table 7-6 summarizes the average weekday ex ante impact estimates for 2028 through 2031 for Rate 5. Rate 5 impacts during the RA window from 4:00 PM to 9:00 PM are expected to increase over time up to 0.027 kW in August during the 1-in-10 weather year. As the COVID-19 indicator reaches zero, per customer impacts are expected to increase in all months and weather years.

Table 7-6: Average 2028-2031 Weekday Ex Ante Impact Estimates Per Customer– Rate 5

Weather Year	Month	SCE		CAISO	
		Impact (kW)	Temperature (°F)	Impact (kW)	Temperature (°F)
1-in-2	January	0.008	62.4	0.008	61.6
	February	0.007	60.7	0.007	61.8
	March	0.005	63.3	0.005	63.4
	April	0.006	65.8	0.006	66.0
	May	0.008	68.2	0.008	68.2
	June	0.009	73.9	0.009	73.9
	July	0.017	78.1	0.017	78.1
	August	0.022	79.4	0.022	79.4
	September	0.018	76.8	0.018	77.2
	October	0.010	71.5	0.010	71.5
	November	0.007	64.9	0.007	63.6
	December	0.008	57.4	0.008	56.5
1-in-10	January	0.008	56.9	0.008	56.9
	February	0.007	64.3	0.007	57.6
	March	0.006	69.5	0.006	69.5
	April	0.006	69.7	0.006	69.5
	May	0.009	73.4	0.009	73.4
	June	0.014	76.5	0.014	76.5
	July	0.022	82.5	0.022	82.5
	August	0.027	82.1	0.026	81.2
	September	0.023	80.5	0.023	80.5
	October	0.013	76.8	0.013	76.8
	November	0.007	65.9	0.007	65.9
	December	0.008	57.3	0.008	58.9

Figure 7-5 presents the average weekday impacts during the RA window under 1-in-2 and 1-in-10 SCE weather conditions for Rate 5 for the years from 2028 through 2031. Similar to the 2021 forecast, expected load impacts are similar between the weather scenarios during winter months, and are higher in the 1-in-10 weather scenario during the summer months when forecasted temperatures are higher.

Figure 7-5: Average 2028-2031 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	0.008	0.007	0.005	0.006	0.008	0.009	0.017	0.022	0.018	0.010	0.007	0.008
SCE 1-in-10	0.008	0.007	0.006	0.006	0.009	0.014	0.022	0.027	0.023	0.013	0.007	0.008

Table 7-7 summarizes the aggregate average weekday 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 2022 under 1-in-10 conditions (29.4 MW). Impacts are lower in the following months as customers leave the rate. As discussed in section 7.1, Rate 5 has a low expected growth rate of about 1,600 customers per month, and an expected attrition rate of 1% per month. Following the default waves in 2021 and 2022 when about one million customers are added to the rate, it has negative growth for the rest of the forecast period and a persistent reduction in aggregate impacts as customers leave Rate 5.

Table 7-7: Aggregate Average Weekday MW Ex Ante Load Impacts during RA Window 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	2021	1.6	1.3	0.9	1.0	1.5	1.1	2.9	4.0	3.1	3.2	3.4	4.3
	2022	6.4	6.4	5.7	6.2	8.5	8.5	17.4	23.4	18.5	10.6	7.7	8.0
	2023	8.7	7.3	5.4	5.9	8.0	8.8	16.8	22.2	17.7	9.9	7.2	7.6
	2024	8.0	6.7	5.1	5.5	7.4	8.5	15.7	20.6	16.5	9.1	6.7	7.0
	2025	7.3	6.1	4.6	5.0	6.7	7.9	14.4	18.9	15.2	8.3	6.1	6.4
	2026	6.7	5.6	4.2	4.6	6.1	7.2	13.2	17.2	13.9	7.6	5.6	5.8
	2027	6.1	5.1	3.9	4.2	5.6	6.6	12.0	15.7	12.7	6.9	5.1	5.3
	2028	5.5	4.7	3.5	3.8	5.1	6.1	11.0	14.4	11.6	6.3	4.6	4.9
	2029	5.1	4.3	3.2	3.5	4.7	5.6	10.1	13.1	10.6	5.8	4.3	4.5
	2030	4.6	3.9	3.0	3.2	4.3	5.1	9.2	12.0	9.7	5.3	3.9	4.1
	2031	4.3	3.6	2.7	2.9	3.9	4.7	8.5	11.1	9.0	4.9	3.6	3.8
SCE 1-in-10	2021	1.6	1.4	1.1	1.2	1.8	2.2	4.1	5.2	4.2	4.2	3.3	4.1
	2022	6.4	6.8	6.9	7.0	10.3	14.2	24.1	29.4	24.2	13.8	7.4	7.8
	2023	8.6	7.7	6.5	6.6	9.6	13.9	22.7	27.5	22.8	12.7	7.0	7.3
	2024	8.0	7.1	6.1	6.1	8.8	13.1	21.1	25.4	21.2	11.7	6.5	6.8
	2025	7.3	6.5	5.5	5.6	8.0	12.1	19.3	23.2	19.4	10.6	6.0	6.2
	2026	6.6	5.9	5.0	5.1	7.3	11.0	17.6	21.2	17.7	9.7	5.4	5.7
	2027	6.0	5.4	4.6	4.7	6.7	10.1	16.1	19.3	16.1	8.8	5.0	5.2
	2028	5.5	4.9	4.2	4.3	6.1	9.2	14.7	17.7	14.8	8.1	4.5	4.7
	2029	5.0	4.5	3.8	3.9	5.6	8.4	13.4	16.1	13.5	7.4	4.1	4.3
	2030	4.6	4.1	3.5	3.6	5.1	7.7	12.3	14.8	12.4	6.8	3.8	4.0
	2031	4.2	3.8	3.2	3.3	4.7	7.1	11.3	13.6	11.4	6.2	3.5	3.7

7.4 Aggregate Default TOU Ex Ante Load Impacts

Table 7-8 presents the estimated total aggregate average weekday load impacts across Rate 4 and Rate 5. Aggregate impacts increase significantly after 2021, following large waves of new default enrollments onto Rate 5 in late 2021 and early 2022 (totaling to around 1.8 million new customers defaulted onto Rates 4 and 5). Although per-customer impacts increase from 2021 through 2031 due to the diminishing effects of the pandemic, aggregate summer impacts begin to decrease starting in 2023 as the Rate 5 population declines.

Table 7-8: Total Average Weekday Aggregate MW Load Reductions during RA Window (Rate 4 and Rate 5)

Weather Year	Forecast Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1-in-2	2021	3.4	2.6	2.5	2.5	4.4	4.4	10.2	12.5	10.0	7.1	8.0	9.2
	2022	12.4	11.3	11.9	11.7	18.6	20.3	41.3	50.0	40.1	20.4	16.6	16.8
	2023	17.2	13.5	12.3	12.1	19.0	22.0	42.7	50.9	41.2	20.5	17.0	17.1
	2024	17.1	13.5	12.5	12.2	19.1	22.8	43.3	51.1	41.5	20.3	17.1	17.1
	2025	16.9	13.3	12.5	12.1	19.0	22.9	43.2	50.6	41.3	20.0	17.0	17.0
	2026	16.5	13.0	12.3	11.9	18.8	22.8	42.8	49.9	40.8	19.6	16.8	16.7
	2027	16.3	12.7	12.2	11.8	18.7	22.7	42.6	49.4	40.3	19.3	16.6	16.5
	2028	16.0	12.5	12.1	11.6	18.5	22.6	42.3	48.9	40.0	19.0	16.5	16.4
	2029	15.7	12.3	12.0	11.4	18.3	22.4	42.0	48.3	39.5	18.7	16.3	16.2
	2030	15.5	12.0	11.9	11.3	18.2	22.2	41.7	47.8	39.1	18.5	16.1	16.0
	2031	15.3	11.9	11.8	11.2	18.0	22.1	41.4	47.3	38.7	18.2	16.0	15.8
1-in-10	2021	3.6	2.8	3.1	2.9	5.5	7.1	14.0	16.0	13.5	10.3	7.7	9.0
	2022	12.8	12.0	14.4	13.5	22.9	31.0	55.6	62.9	52.5	28.6	16.2	16.5
	2023	17.7	14.3	14.8	13.9	23.2	32.4	56.7	63.6	53.4	28.6	16.6	16.9
	2024	17.7	14.3	14.9	13.9	23.2	32.9	57.0	63.5	53.5	28.4	16.7	16.9
	2025	17.5	14.0	14.8	13.8	23.1	32.9	56.7	62.8	53.0	28.0	16.6	16.8
	2026	17.2	13.7	14.7	13.6	22.9	32.5	56.2	62.0	52.4	27.6	16.4	16.6
	2027	16.9	13.4	14.5	13.4	22.7	32.2	55.7	61.3	51.8	27.2	16.2	16.4
	2028	16.7	13.2	14.4	13.3	22.5	32.0	55.3	60.6	51.3	26.9	16.1	16.2
	2029	16.4	12.9	14.2	13.1	22.3	31.6	54.8	59.9	50.7	26.6	15.9	16.0
	2030	16.2	12.7	14.1	12.9	22.1	31.3	54.4	59.3	50.2	26.3	15.7	15.8
	2031	16.0	12.5	14.0	12.7	21.9	31.0	54.0	58.8	49.8	26.0	15.6	15.7

7.5 Comparison between Ex Post and Ex Ante

Table 7-9 facilitates a comparison of per-customer ex ante impacts to average weekday ex post load impact estimates for each month from October 2019 through September 2020 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 7-9. The same logic can be used to step through the remaining rows of the table. Impacts are presented for the RA window and ex ante forecasts are from the 2021 forecast year, where the COVID-19 indicator was equal to 0.5 (meaning that the pandemic is expected to half the effect on electricity demand that it did from March to December 2020).

On average, the summer ex post impact for Rate 4 was 0.016 kW, seen in the third column of Table 7-9. For comparison, the 2021 SCE 1-in-10 load impact for an average summer weekday is 0.019 kW, which is slightly higher due to the higher ex ante *mean17* value under the 1-in-10 conditions.

- First, on average, 0.016 kW was delivered by Rate 4 during summer months where the *mean17* was equal to 72.3 °F.

- At those temperature conditions, our ex ante model predicts that Rate 4 load impacts from 4:00 to 9:00 PM will be 0.015 kW. This is only 0.001 kW smaller than the ex post estimate, indicating that the model predicts well using historical weather data.
- The ex post impacts fall between the estimates under SCE 1-in-2 and 1-in-10 weather conditions, which is expected because PY2020 weather was warmer than the 1-in-2 scenario but cooler than the 1-in-10 scenario, on average.

Table 7-9: Comparison of Average Weekday Ex Post and Ex Ante Impacts – Rate 4

Month	Ex Post Weather			SCE1-in-2		SCE1-in-10	
	Mean17	Ex Post Peak Impact (kW)	Ex Ante Peak Impact using Ex Post weather	Mean17	Ex Ante Peak Impact (kW)	Mean17	Ex Ante Peak Impact (kW)
January	55.6	0.004	0.006	56.7	0.005	52.1	0.006
February	56.8	0.004	0.005	55.7	0.004	58.8	0.004
March	57.7	0.003	0.003	57.4	0.004	61.8	0.005
April	61.2	0.004	0.003	59.6	0.004	62.1	0.004
May	63.3	0.009	0.008	62.5	0.007	66.2	0.009
June	68.4	0.010	0.010	66.4	0.007	69.3	0.011
July	73.8	0.018	0.014	70.9	0.016	75.3	0.021
August	75.0	0.020	0.021	71.5	0.018	75.1	0.023
September	72.1	0.016	0.016	70.7	0.014	74.1	0.019
October	67.6	0.009	0.009	65.4	0.006	70.5	0.010
November	60.2	0.006	0.007	61.0	0.006	60.7	0.006
December	54.7	0.005	0.007	54.1	0.006	52.9	0.006
Winter	**59.6**	**0.006**	**0.006**	**59.0**	**0.005**	**60.6**	**0.006**
Summer	**72.3**	**0.016**	**0.015**	**69.9**	**0.014**	**73.4**	**0.019**
All	**63.9**	**0.009**	**0.009**	**62.6**	**0.008**	**64.9**	**0.010**

Table 7-10 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 only includes the hours from 5:00 PM to 8:00 PM. The average ex post impact in the summer months is 0.014 and the modeled impact is 0.012, indicating that the ex-ante model slightly under-predicts during the summer months. However, more than 20 models were tested, and the current model provided the best predictions across all months.

Table 7-10: Comparison of Average Weekday Ex Post and Ex Ante Impacts – Rate 5

December	Ex Post Weather			SCE1-in-2		SCE1-in-10	
	Mean17	Ex Post Peak Impact (kW)	Ex Ante Peak Impact using Ex Post weather	Mean17	Ex Ante Peak Impact (kW)	Mean17	Ex Ante Peak Impact (kW)
January	55.6	0.006	0.008	56.7	0.007	52.1	0.007
February	56.7	0.006	0.007	55.6	0.006	58.8	0.006
March	57.7	0.004	0.003	57.4	0.004	61.8	0.005
April	61.2	0.004	0.004	59.5	0.004	62.1	0.005
May	63.3	0.008	0.007	62.5	0.006	66.2	0.008
June	68.4	0.009	0.008	66.4	0.005	69.3	0.010
July	73.8	0.013	0.009	70.9	0.013	75.3	0.018
August	75.0	0.018	0.019	71.5	0.018	75.1	0.023
September	72.1	0.015	0.014	70.7	0.014	74.1	0.019
October	67.6	0.013	0.011	65.3	0.009	70.5	0.011
November	60.2	0.007	0.007	61.0	0.006	60.7	0.006
December	54.6	0.005	0.008	54.0	0.006	52.9	0.006
Winter	**59.6**	**0.007**	**0.007**	**59.0**	**0.006**	**60.6**	**0.007**
Summer	**72.3**	**0.014**	**0.012**	**69.9**	**0.012**	**73.4**	**0.017**
All	**63.9**	**0.009**	**0.009**	**62.6**	**0.008**	**64.9**	**0.010**

Appendix A Memo regarding TOU Default Notification of Control Group Customers

Memorandum

March 11, 2021

To: Prapti Gautam, Jenny Chen; SCE

From: Eric Bell, Aimee Savage; Nexant

RE: SCE D-TOU PY2020 Evaluation- TOU Default Notification of Control Group Customers

---

Background

On March 8, 2021, SCE informed Nexant that a portion of customers originally designated as control group customers for the Default TOU Pilot evaluation received notification about being defaulted onto a TOU rate. The control group customers were on the standard tiered rate, and are used for comparison with customers who were defaulted onto a TOU rate as part of the Default TOU Pilot evaluation (the full default roll-out does not set aside a control group). Recent default enrollments, including the control customers who received notifications, were expected to benefit on a TOU rate and were located in Orange, Mono, Inyo, and San Bernardino counties. The notification was distributed in late June or early July, 2020, and informed customers that they would be defaulted onto a TOU rate beginning in October of 2020. The customers who received the notifications were not scheduled to be defaulted during the observation period for the 2020 evaluation, which ran from Oct. 1, 2019 through Sept. 30, 2020. However, there is concern whether receiving the notification about the upcoming rate change may have influenced their energy consumption behavior during the months of July, August, and September, 2020, which could in turn have influenced the load impact estimations.

If the notified control group customers started to behave as though they were on a TOU rate prior to the rate change-over in October, 2020, it is possible that they reduced usage during the peak period. The consequence of this happening, under the current evaluation approach, would be reduced load impacts for the treatment customers. This is because the load impact estimates are fundamentally based on the observed differences in load between the treatment and control groups. For example, if the control customers used 2 kW, and the treatment customers used 1.5 kW, then the load impact is 2 kW - 1.5 kW = 0.5 kW. If a portion of the control customers responded to the rate during the months after receiving the notification prior to being defaulted, they would show a decrease in usage. For example, 1.8 kW for control customers, and 1.5 kW for treatment customers. 1.8 kW - 1.5 kW = 0.3 kW. In this example, we observe an artificial reduction in load impacts attributable to the control customers responding to the forthcoming default notification.

The prior example illustrates a potential outcome from the control group customers receiving the default notifications for illustrative purposes. However, additional analysis is needed to determine the potential for the notifications to have influenced the load impact estimates in a substantive manner. This memo presents analyses conducted by Nexant in order to determine if the control group customers receiving default notifications appears to have resulted in meaningful differences in outcomes. If the analysis shows that the risk for differences in outcomes is minimal, then it is probably sufficient to include a footnote in the current report documenting the situation, and noting that it is not believed that it materially affected the reported load impacts. If the opposite is found, then it will be necessary to change the analysis approach to using a matched control group, instead of the current randomized encouragement design (RED). Changing approaches will require requesting an extension to the current deadlines, and may require additional budget.

Based on the observed outcomes documented in this analysis, it is Nexant's recommendation to not change the analysis approach from the current RED design to an analysis based on matched control group. The matched control group approach is the next best analysis approach when a RED or RCT design is not possible. However, based on the simulation not resulting in statistically significant differences in load impacts, the accuracy of the analysis lost to matching wouldn't justify switching from the RED analysis to matching, as the RED design is a more rigorous analysis approach.

The remainder of this memo will be divided into 3 topics:

- Population of affected customers
- Load characteristics of affected customers
- Simulation of notified group customer response impacts

Population of affected customers

SCE provided Nexant a list of Pilot control customers who received default TOU notification. The following tables show the disposition of how those customers who received the notification fit within the broader control group population. Tables 1 through 4 show the breakout by climate region, Local Capacity Area (LCA), CARE/FERA status, and Summer Discount Program (SDP) participation, respectively. The most notable observation is found in Table 1, where we see that the 14,012 control customers who received the notification represent a relatively small proportion of the overall control group population at approximately 8.6%. It is also important to note that 12,796 out of the 14,012 (91%) of the notified customers are located in the cool climate region.

From the perspective of the integrity of the evaluation, this is a positive finding as customers in the cool climate region tend to have lower levels of load, and smaller load impacts. Additionally, the notified customers were expected to benefit on a TOU rate, meaning there is not a large financial incentive to shift behavior. Therefore, if the notified control group customers were responding to having received the default notification, their load impacts are expected to be relatively small.

The combination of the notified customers being TOU benefiters, comprising only 8.6% of the total control population, and 91% of those notified customers being in the cool climate region helps to minimize the potential for the notified control customers influencing the overall findings from the evaluation.

Table 1: Notified Control Customers, by Climate Region

Climate Region	Non-Notified	Notified	Total
Cool	76,421	12,796	89,217
Hot	8,113	510	8,623
Moderate	44,298	33	44,331
Zone 10	20,172	673	20,845
Total	**149,004**	**14,012**	**163,016**

Table 2: Notified Control Customers, by LCA

LCA	Non-Notified	Notified	Total
La Basin	117,217	12,106	129,323
Outside LA Basin	9,355	1,819	11,174
Ventura/Big Creek	22,432	87	22,519
Total	**149,004**	**14,012**	**163,016**

Table 3: Notified Control Customers, by CARE/FERA Status

CARE/FERA	Non-Notified	Notified	Total
No	118,249	10,900	129,149
Yes	30,755	3,112	33,867
Total	**149,004**	**14,012**	**163,016**

Table 4: Notified Control Customers, SDP Participation

SDP	Non-Notified	Notified	Total
No	140,883	13,457	154,340
Yes	8,121	555	8,676
Total	**149,004**	**14,012**	**163,016**

Load Characteristics

This section documents the load characteristics of the control group customers who received the notifications, and compares them with control customers who did not receive notifications. The figures in this section are limited to the cool climate region for the months of July, August, and September in 2020. The cool climate region is the focus of this section because it represents approximately 91% of the customers who received the default notifications.

Peak period load at various temperatures across groups and years

Figures 1 and 2 present scatter plots of average peak period kW on weekdays for control customers in 2017, 2018, 2019, and 2020. Figure 1 presents the customers who received default notifications, and Figure 2 presents the control customers who did not receive notifications. The Y-axis represents the average peak period kW, and the X-axis represents the temperature during the peak period. The format of the scatter plot allows us to see how the peak period load changes with temperature. In these graphs, we can clearly see that the kW load is increasing with temperature. Linear trends are provided for each year to help better illustrate trends that are occurring between the years.

Interestingly, we see that 2017, 2018, and 2020 are all very similar to one another, with only 2019 showing lower peak period kW across all temperatures. It is not clear why the 2019 usage is lower for the customers who received the notifications. But, we do see a pattern where 2020 kW load is higher than 2019, which is consistent with most customers during the COVID-19 pandemic.

Figure 1: Notified Control Customers Summer Peak kW Weather Relationship in Cool Climate Region, by Year (4 PM to 9 PM, July- September)

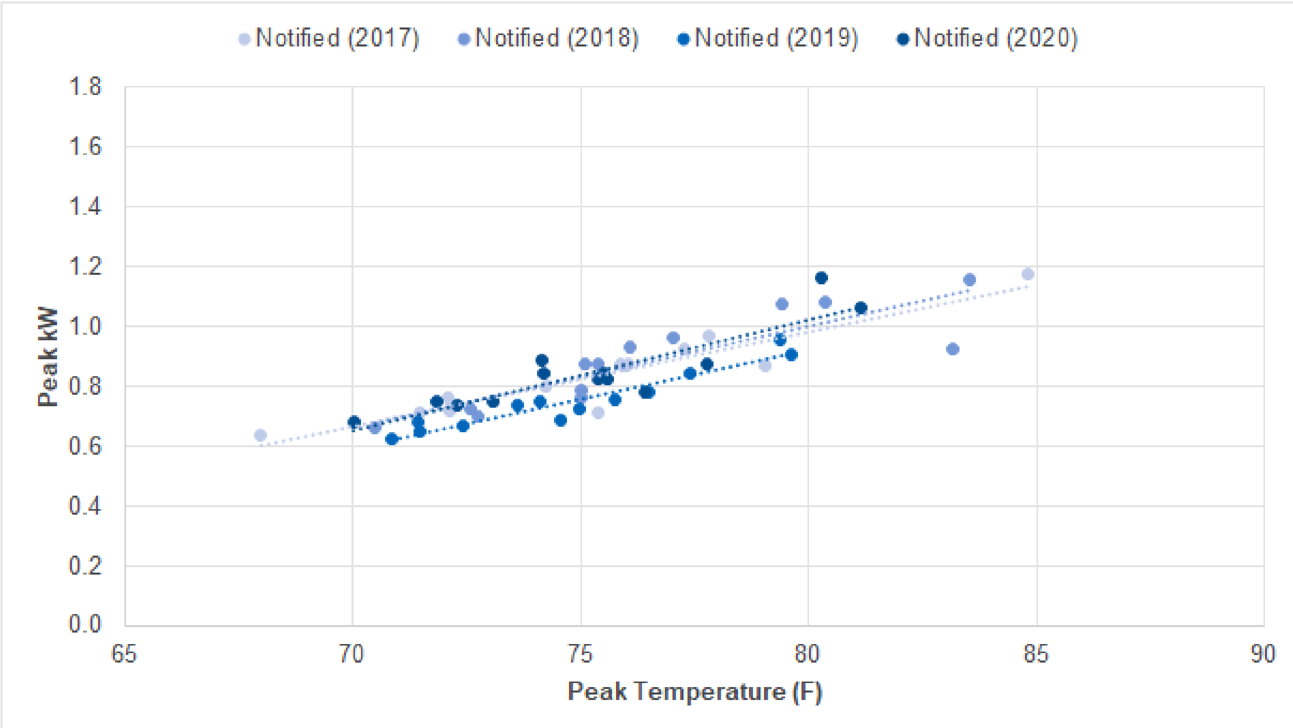
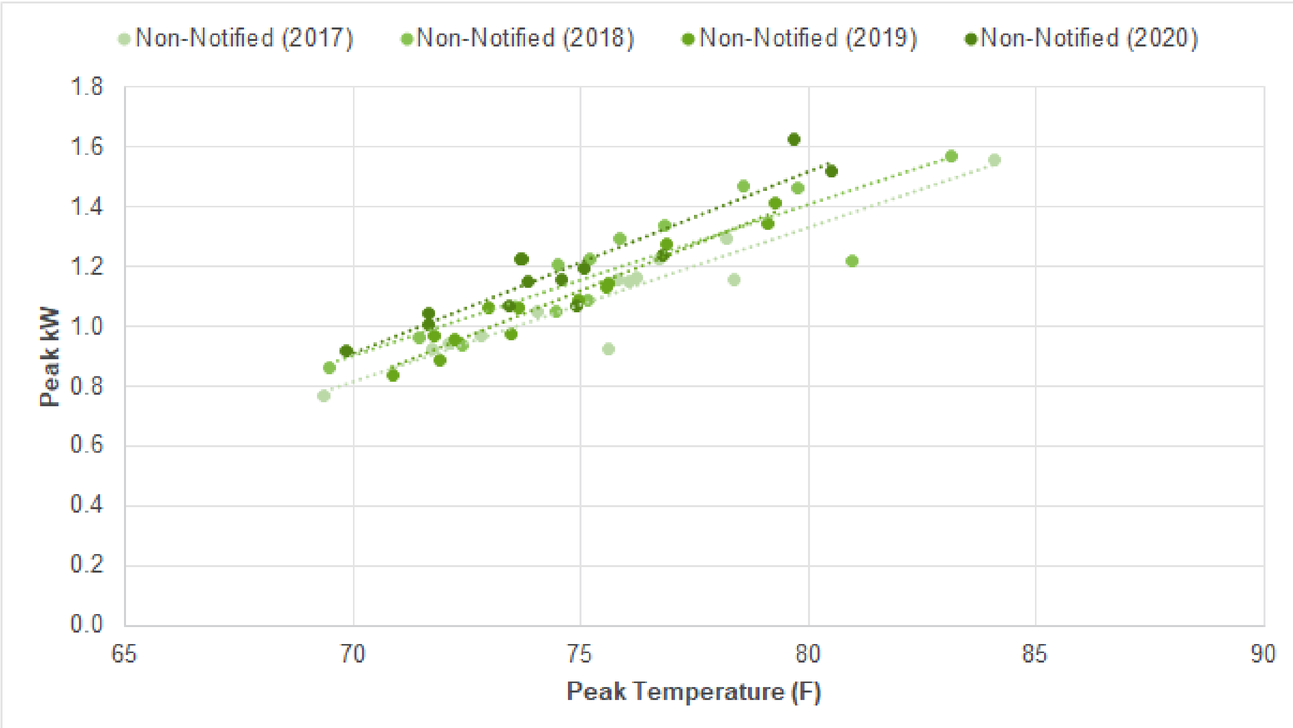


Figure 2 provides a contrast to Figure 1, as it focuses on the load from customers in the cool climate region who did not receive the notification. It is important to note that customers were specifically selected to be defaulted onto TOU rates based on their consumption patterns. Accordingly, these customers in Figure 2 are fundamentally different from customers in Figure 1. The pattern that we see here is that again, 2020 kW is higher than the peak period load from 2019. However, the earlier years tend to be lower as well. It isn't possible to say why we are observing this difference, other than to say that we know these are fundamentally different customers. If there was a clear pattern of differences between these two groups between Figure 1 and Figure 2, it may be possible to ascertain if the default notifications caused a difference in behavior. But, based on this data the answer is indeterminate.

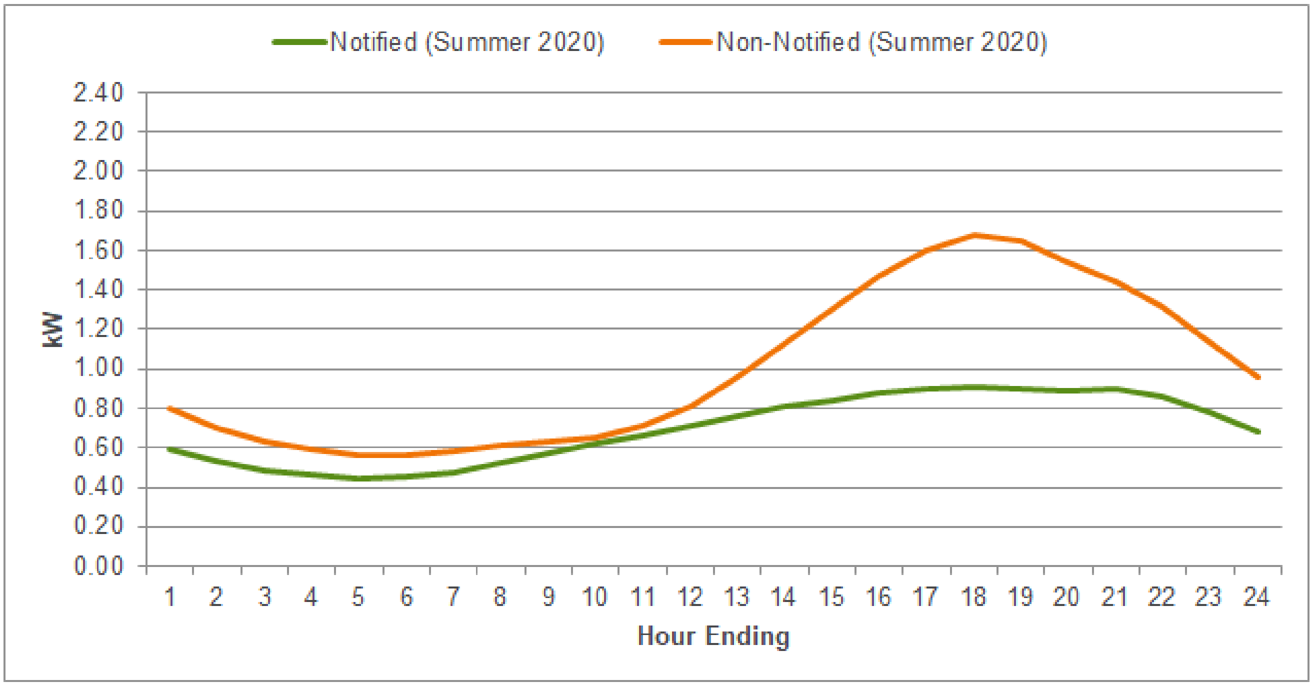
Figure 2: Non-Notified Control Customers Summer Peak kW Weather Relationship in Cool Climate Region, by Year (4 PM to 9 PM, July - September)



July, August, September hourly load shapes by group and year

Given the rather indeterminate answer based on the scatter plots, we decided to analyze the load shapes to see if notified customers showed any indication of load reductions starting at 4 PM or 5 PM when the new TOU rates would start. Figure 3 shows the overall load shape for the notified and non-notified customers across all climate regions from the months of July, August, and September in 2020. The first major observation is how different the load shapes are from the customers who received the notifications (much flatter load shapes in green) compared to the remaining control group customers in orange with much higher peaks. The notified customers also tend to show a slight dip in the load curve in the evening, starting at around hour ending 19. However, as the subsequent figures will show, this existed in prior years as well. The dip also starts well after the TOU peak period, making it highly unlikely to be related to the default notifications. It is also interesting to note that the non-notified and the notified customers are both showing a dip in the early evening in the Figures 4, 5, and 6 below which are specific to the cool climate region.

Figure 3: Summer Electricity usage, by Notification Status (July, August, and September) All Climate Regions



Figures 4, 5, and 6 show the hourly usage trends for notified and non-notified customers in the cool climate region for 2018, 2019, and 2020 for July, August, and September, respectively. There does not appear to be any discernible pattern that would indicate that the notified customers were behaving any differently during the TOU periods in 2020 than they were in the prior years. However, it is difficult to determine on a visual basis from the graphs. Accordingly, the next section provides a scenario analysis to simulate the effect on load impacts if the notified control customers did respond to the notifications.

Figure 4: July Electricity usage, by Notification Status, Cool Climate Region

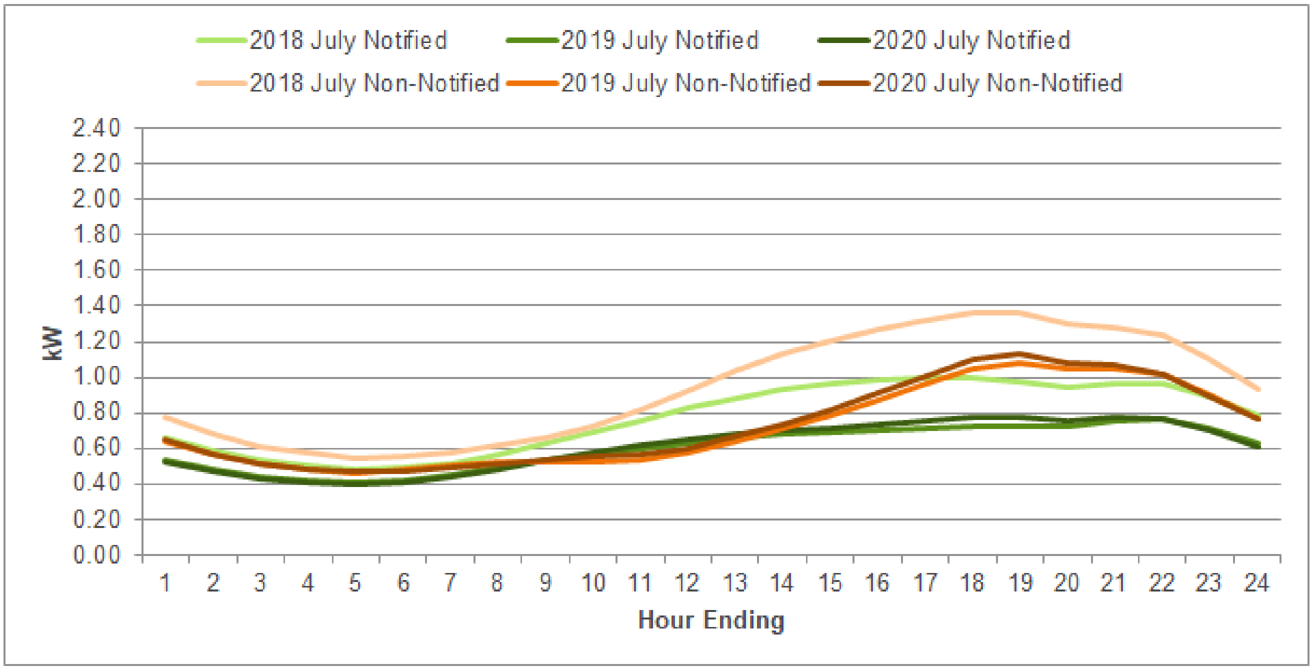


Figure 5: August Electricity usage, by Notification Status, Cool Climate Region

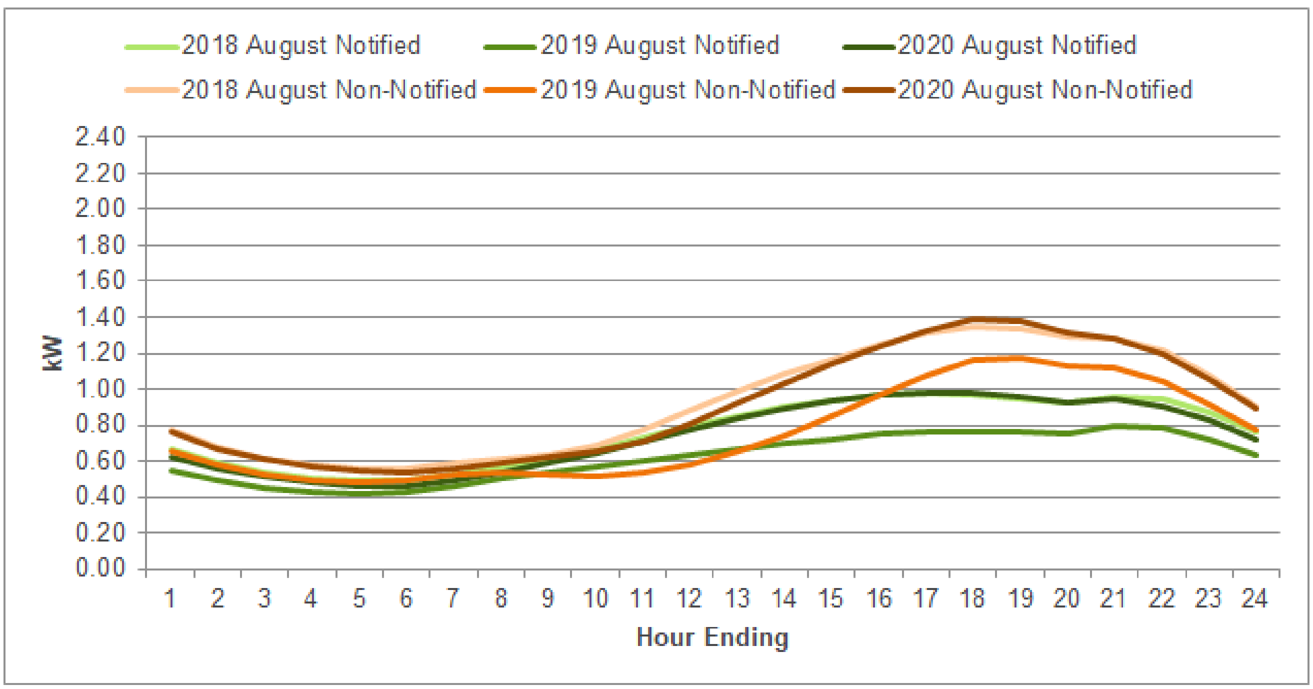
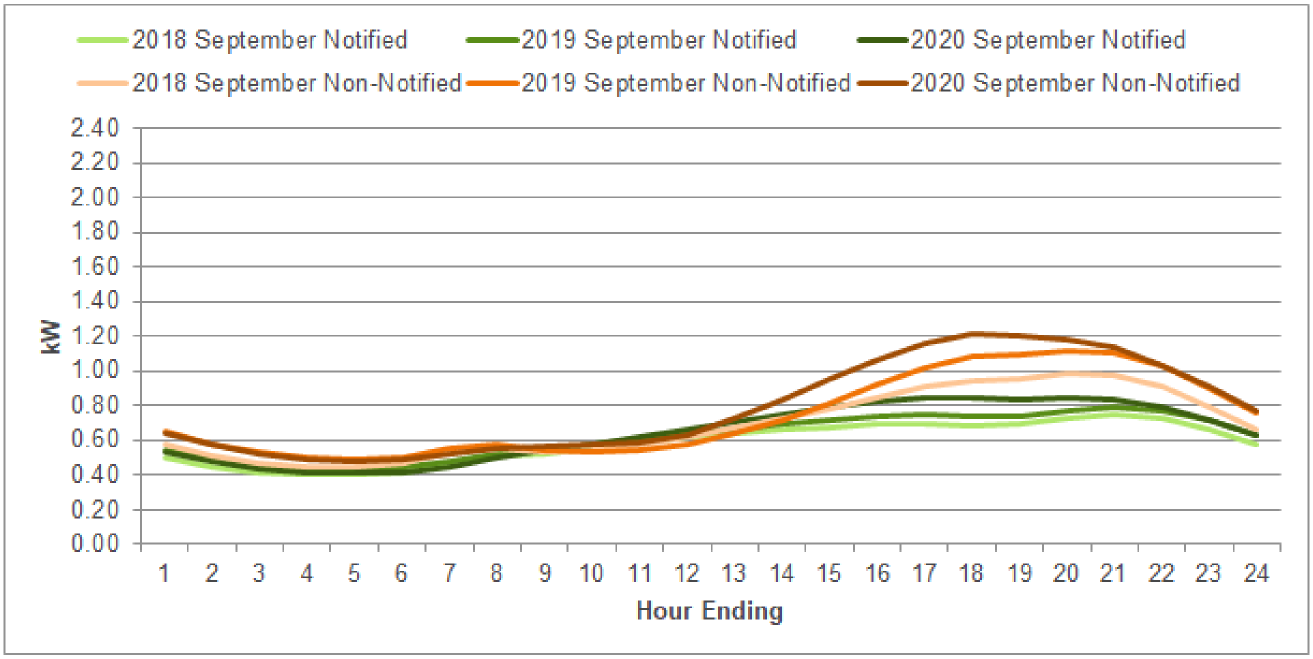


Figure 6: September Electricity usage, by Notification Status, Cool Climate Region



Simulation of notified customer group response impacts

The scatter plots and load shape figures in the prior section did not provide visual confirmation of the notified control customers responding to the default notifications. The analysis in this section simulates the effect on the overall pilot load impacts as if the notified control group population did respond to the notification, and assumes that the notified control group customers produced load impacts consistent with the treated customers in their respective climate regions. Table 5 provides definitions of each of the variables presented in Table 6. At a high level, the general approach was to determine the typical load impact for customers in each climate region, and determine the load impact the notified control group customers might have had if they were enrolled on the pilot rate. The potential load impact was then added to the reference load for the notified customers to estimate what they may have used in the absence of responding to a TOU rate. As the load impact is the reference load minus the load from the treatment group, this would increase the overall reference load and subsequently increase the load impacts.

As we saw from the figures in the prior section, the notified customers had much lower peak period load. The load impacts used to develop the assumed kW impacts for the notified customers are based on the full population in the respective climate regions, and are likely much larger than the load impacts the notified control group customers would have produced if they were actually on a TOU rate. This results in the following analysis representing an upper bound to the level of influence we might expect had these notified customers responded to the default notification.

Table 5: Variable Definitions

Variable	Definition
Treatment kW	Average hourly peak period kW for treatment customers
Reference kW Full Population	Average hourly load during peak period from control group customers
Reference kW (Non-Notified)	Average hourly load during peak period from control group customers who did not receive default notification
Reference kW (Notified)	Average hourly load during peak period from control group customers who did received default notification
Assumed kW Impact for Notified	kW impact derived from observed impacts from treatment group customers weighted by the climate regions for the notified customers. This is likely the upper bound for any sort of load impacts from customers who received notifications- based on the climate regions of the notified customers. There are two reasons for this. First, the notified control customers were not enrolled on the rate until October 2020 (outside of the evaluation period). Second, the customers who were notified are customers who are expected to save money on the TOU rate (benefiters), who would potentially have smaller impacts than the general Pilot population. With this in mind, it is likely that any load reductions within the notified population are smaller than those of treatment customers in the Pilot.
Adjusted Notified Reference kW	Reference kW for notified customers + assumed kW impact for notified customers. Essentially, the assumed load impact is added to the known reference load
Combined Adjusted Reference kW	The population weighted reference kW from the non-notified population combined with the adjusted notified reference kW. This represents what we think the reference load could have been if the notified customers did respond, and those impacts are added back.
Original Impact kW	Original load impact (Reference kW Full Population - Treatment kW) based on load impact tables
Adjusted Impact kW	Adjusted impacts based on adding back any potential load impacts from notified control group customers (Combined Adjusted Reference kW - Treatment kW)

Table 6 presents the outcomes from the simulation. The reference kW for the full population increased from 1.5236 kW to 1.5247 kW based on adding in an assumed 0.0130 kW load impact per notified control group customer. The result of this change is the original impact of 0.0180 kW increased slightly to 0.0191 kW, an increase of 0.0011 kW. Results are typically presented with two decimal places, and are shown at four decimal places in order to show the small differences in this analysis. When the results are presented at the second decimal place, both results are impacts of 0.02 kW. The 90% confidence interval of the original impact is 0.0180 kW +/- 0.0018 kW. Therefore, the observed difference of 0.0011 kW is well within the 90% confidence interval and the results are not statistically significantly different.

As noted above, we expect this is the upper bound of possible outcomes because (1) the customers only received notifications but weren't actually enrolled on the rate yet and (2) they are benefiters who would potentially have smaller impacts anyway, even within the cool climate region. Indeed, it is likely that their load impacts would be less than customers who are actually enrolled.

Based on the observed outcomes from this analysis, it is Nexant's recommendation to not change the analysis approach from the current RED design to an analysis based on matched control group. The matched control group approach is the next best analysis approach when a RED or RCT design is not possible. However, the accuracy lost to matching wouldn't justify switching from the RED analysis to matching, as the RED design is a more robust analysis approach.

Table 6: Simulation of Reference Load Adjustment

Treatment kW	Reference kW (Full Population)	Reference kW (Non-Notified)	Reference kW (Notified)	Assumed kW Impact for Notified	Adjusted Notified Reference kW	Combined Adjusted Reference kW	Original Impact kW	Adjusted Impact kW
1.5056	1.5236	1.5824	0.8981	0.0130	0.9112	1.5247	0.0180	0.0191

Headquarters
45 Stevenson Street, Suite 700
San Francisco CA 94105-3651
Tel: (415) 369-1000
Fax: (415) 369-9700
www.nexant.com