



2019 Load Impact Evaluation of San Diego Gas and Electric's Residential Default Time-Of-Use Rates

Prepared for:

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1 Executive Summary

This report documents the 2019 load impact evaluation of San Diego Gas & Electric Company's (SDG&E) 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 continue to help guide SDG&E'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 October 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 SDG&E'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 November 2018 through May 2019. Behavioral bill impacts and total bill impacts are provided for the full first year of the pilot, from June 2018 through May 2019. Customer attrition throughout the first year is also included in the Final Report.

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

1.1 Pilot Background and Design

The pilot tested two different TOU rate options: Rate 1 and Rate 2. Approximately 141,000 households were assigned to one of the two TOU rates, and an additional 169,000 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 choice of staying on their otherwise applicable tariff or selecting an alternative TOU rate plan. If a customer took no action, they were placed on the default rate associated with their assigned group.

Figure 1-1 and Figure 1-2 show the timing of the rate periods for Rates 1 and 2 and the prices¹ in each period. Rate 1 is a three-period rate in summer and winter. Prices are the same on weekdays and weekends but weekends have a longer super off-peak period relative to

¹ Prices do not reflect the baseline credit of \$0.10 per kWh for electricity usage up to 130% of the customer's baseline allocation.

weekdays. The peak period in both summer and winter is from 4 to 9 PM. The rate structure for winter is the same as summer except for the months of March and April where there is an additional super off-peak period from 10 AM to 2 PM. The peak-to-super-off-peak price ratio in summer is 1.9:1 for usage above the baseline quantity. In winter, the peak and off-peak prices are very similar, as super off-peak prices are nearly 6% lower than peak-period prices. The structure of Rate 2 is simpler compared to Rate 1 as there are only two rate periods that don't vary throughout the year or on weekdays or weekends. The peak period is the same as Rate 1 (4 PM to 9 PM) and the remaining period is an off-peak period from 9 PM to 4 PM.

Figure 1-1: Default Pilot Rate 1²

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	Super Off-Peak (29¢)						Off-Peak (35¢)									Peak (56¢)								
	Winter	Super Off-Peak (35¢)						Off-Peak (36¢)									Peak (37¢)								
	March - April	Super Off-Peak (35¢)						Off-Peak (36¢)									Peak (37¢)								
Weekend	Summer	Super Off-Peak (29¢)																Peak (56¢)							
	Winter	Super Off-Peak (35¢)																Peak (37¢)							

Figure 1-2: Default Pilot Rate 2

Day Type	Season	Hour Ending																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Weekday	Summer	Off-Peak (34¢)																Peak (53¢)							
	Winter	Off-Peak (36¢)																Peak (37¢)							
Weekend	Summer	Off-Peak (34¢)																Peak (53¢)							
	Winter	Off-Peak (36¢)																Peak (37¢)							

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.

Based on pre-treatment validations it was determined that an error had occurred in the pilot implementation and the control groups were not statistically equivalent to the treatment groups. Without pre-treatment statistical equivalence between the treatment and control groups, the RED analysis framework was no longer valid. SDG&E selected a revised control group for each rate from the original pool of eligible customers. The revised control group for Rate 2 was statistically equivalent to the treatment group. However, the Rate 1 control group was not. As a result, statistical matching was implemented to select a revised control group for the Rate 1 population. Statistical matching involves selecting customers from a population of customers who were not subject to default notification that are most similar to the participant population

² Rates effective June 1, 2019, and do not reflect the baseline credit of approximately .10 cents kWh for usage up to 130% of baseline.

based on observable variables (primarily load shape). The approach to selecting a matched control group is described in Section 3 of the Interim Report.

Load impacts were estimated separately for net metered and non-net metered customers on the pilot rates. Load impacts were also estimated for three different climate regions in SDG&E's service territory (hot, moderate, and cool). For the moderate and cool climate regions, estimates were also made for two customer segments, CARE/FERA customers and non-CARE/FERA customers. CARE/FERA customers in the hot climate region were not allowed to be enrolled on TOU tariffs using default recruitment. As such, comparisons across the 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.

1.2 Overall Findings

1.2.1 Ex Post Load Impacts

Table 1-1 presents the average weekday peak period load reduction for each pilot rate. Key findings for load impacts are summarized in following the table.

Table 1-1: Peak Period Load Reductions on Average Weekday³

Utility	Metric	Rate 1 Summer Non-NEM	Rate 1 Summer NEM	Rate 2 Summer Non-NEM	Rate 2 Summer NEM
SDG&E	Peak Period Hours	4-9 PM	4-9 PM	4-9 PM	4-9 PM
	% Impact	1.1%	-0.6%	1.8%	N/A
	Absolute Impact (kW)	0.01 kW	-0.01 kW	0.01 kW	N/A
	Average Number of Enrolled Customers	68,332	3,393	17,424	2,269
	Number of Customers in Analysis	66,928	903	16,942	0

Key findings pertaining to load impacts from the SDG&E pilots include:

- Customers who are net energy metered (NEM), meaning that they have installed solar generation systems, have a significant influence on the overall TOU population, distorting load impact results and the quality of the matched control group as NEM

³ The average number of enrolled customers in this table represents the average number of customers enrolled during the summer months by rate and NEM status. The differences in customer counts between enrolled and analyzed customers are due to data incompleteness and exclusion of customers who transitioned to NEM during the pre-treatment or treatment periods of the pilot. Rate 2 did not have any NEM customers prior to the pre-treatment or treatment periods of the pilot.

enrollments varied over the pilot period. For this reason, this analysis focused on customers who never became NEM during the evaluation period (non-NEM). Separately, the evaluation recreated the matched control group and performed analysis for NEM customers who had become NEM at least one year prior to the treatment period. See Section 3.1.3 for additional details.

- During the first summer, the average number of eligible customers for the analysis was 88,169 for Rate 1 and 20,781 for Rate 2. For the current analysis, after including the additional exclusion of the NEM enrollments after the pre-treatment period, the average number of customers included in the analysis was 67,831 for Rate 1 and 16,942 for Rate 2. The decrease in customers between summers was primarily due to customer attrition and account terminations (Section 5).
- On average, default customers on both Rates 1 and 2 produced small, but statistically significant, peak-period load reductions in the summer months. Peak period load reductions averaged roughly 1.1% for Rate 1 and 1.8% for Rate 2 (Sections 5.2 and 5.3).
 - These percentage reductions were similar to those from the previous pilot evaluation, which saw load reductions of 1.5% for Rate 1 and 2.0% for Rate 2.
- In the summer months, load reductions were greater for Rate 2 than for Rate 1, despite having the same peak period time period (4 PM to 9 PM) and despite Rate 1 having higher peak-period prices than Rate 2. While the difference between Rate 1 and Rate 2 impacts are statistically significant, it is important to keep in mind that the estimates were calculated using different estimation techniques and the populations are not equivalent in size or distribution (Section 5.4).
- At the territory level, neither customers on Rate 1 nor Rate 2 showed a statistically significant change in net daily electricity consumption on any day types during the second summer compared to the pretreatment period (Table 5-1 and Table 5-4). The evaluation of the first summer found small, but statistically significant changes in net daily consumption for both rates.
- In the summer months, the pattern of load reductions varied across climate regions between the two rates. For Rate 1, the moderate climate region had the largest impacts of 1.6%, while the hot climate region showed -1.4% (however, this was not statistically significant due to small population size). For Rate 2, all climate regions showed larger impacts. The hot climate region showed the highest statistically significant impacts of 4.2% or 0.04 kW. Absolute peak period load reductions were largest in the hot climate region, but these segments did not include CARE/FERA customers. Absolute impacts were smallest in the cool climate region, which included CARE/FERA and non-CARE/FERA customers (Sections 5.2 and 5.3).
- In the moderate and cool climate regions in the summer, non-CARE/FERA customers typically had statistically significantly greater absolute peak-period impacts compared to CARE/FERA customers. As found in the previous evaluation's surveys, this could be due to the non-CARE/FERA customers' greater knowledge of the TOU rate plan and its associated peak hours. Efforts to more effectively educate CARE/FERA customers regarding their TOU rate plan could improve load reductions for this customer segment (Sections 5.2 and 5.3).

- NEM customers in Rate 1 showed small load increases of 0.01 kW (0.6%) during the peak period. However, due to the small sample size (approximately 900 customers), the negative impacts are not statistically significant. Treatment customers show slightly higher usage during the middle of the day when solar generation is at its highest. This effect persists into the first two hours of the peak period (Section 5.2.2).

1.2.2 Persistence of Load Impacts

An additional analysis was conducted to explore the impacts for customers who remained active SDG&E D-TOU customers from April 2018 until the end of October 2019. Key findings pertaining to the load impacts for these persistent customers include:

- Load impacts for the persistent customers generally decreased between the two summers of the pilot. Impacts for the first and second summer were about 1.6% in 2018 and 1.1% in 2019. The difference was statistically significant (Section 6.1 and Section 6.2).
- For the territory as a whole, load impacts were smaller in winter of 2018/2019 than in the two summer seasons. For Rate 1, the winter impacts for the persistent set of customers was 1.1%, while the summer 2018 impact was 1.7% and the summer 2019 impact was 1.3% (Section 6.1). For Rate 2, the winter impact was 0.9%, while the summer 2018 impact was 2.3% and the summer 2019 impact was 1.8% (Section 6.2).
- Rate 1 NEM customers showed a statistically significant decrease in impacts after the first summer in both the winter and second summer. The percentage impacts decreased from 5% to -0.9% in the winter and -0.5% in the second summer (Section 6.1).
- For all climate zones for both rates, there was a decrease in impacts between the first summer and the second summer. For Rate 1, the largest statistically significant decrease was in the moderate climate zone (2.2% to 1.5%) (Section 6.1). For Rate 2, the largest statistically significant decrease was in the cool climate zone (2.0% to 1.2%) (Section 6.2).
- On average, temperatures were cooler in 2019 (average *mean* of 69 °F versus 71 °F in 2018). At similar temperatures, impacts in 2019 were slightly lower than impacts in 2018. It may be possible that customers were slightly less responsive to the rates in the second summer (Section 6.3).

1.2.3 Ex Ante Load Impacts

Key findings pertaining to the ex ante analysis include:

- Territory-wide mass defaulting of residential customers throughout 2019 led to a large growth in the starting point for the enrollment forecast for the ex ante analysis, beginning at about 700,000 for Rate 1 and 28,500 for Rate 2 in March 2020. The TOU Enrollment onto Rate 1 is expected to grow at a rate of 1% per year to approximately 780,000 by 2030. After 2021, no new enrollments are anticipated for Rate 2, and the population is expected to decline by approximately 1% per year (based on account closure and opt out rates observed in 2018 and 2019). The Rate 2 population is expected to reach 27,000 by 2030 (Section 7.1).
- Generally speaking, ex post and ex ante load impacts are larger under higher temperatures. As such, the largest ex ante impacts (over 0.014 kW per customer on Rate 1 and 0.018 kW on Rate 2) are forecasted for 1-in-10 weather conditions during the

hottest summer month (July). Winter ex ante load impact estimates are expected to be similar under 1-in-2 and 1-in-10 weather conditions (Sections 7.2 and 7.3).

- The ex ante load impacts under SDG&E 1-in-2 weather conditions are similar to the ex post load impact estimates. This finding is expected as the average monthly temperatures are similar between November 2018 through October 2019 and the ex ante weather conditions. The temperatures under 1-in-10 weather condition are warmer than the ex post weather conditions; therefore, the load impacts under the 1-in-10 conditions are expected to be greater than the ex post load impacts (Sections 7.2 and 7.3).
- In 2020, the largest aggregate ex ante impact estimates are in August under SDG&E weather scenarios. For Rate 1, they are estimated to be 8.0 MW for 1-in-2 weather conditions, and 9.7 MW for 1-in-10 conditions (Section 7.2). For Rate 2, the estimates for the same conditions are 0.4 MW for 1-in-2 and 0.5 MW for 1-in-10 (Section 7.3).

2 Introduction

The pilot tested two different TOU rate options: Rate 1 and Rate 2. Approximately 141,000 households were assigned to one of the two TOU rates, and an additional 169,000 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 choice of staying on their otherwise applicable tariff or selecting an alternative TOU rate plan. 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 October 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 SDG&E’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 November 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.

Figure 2-1 and Figure 2-2 show the timing of the rate periods for Rates 1 and 2 and the prices in each period. Importantly, the prices shown in the figures do not reflect the baseline credit of 10¢/kWh that applies to each rate.

Figure 2-1: Default Pilot Rate 1⁴

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	Super Off-Peak (29¢)						Off-Peak (35¢)									Peak (56¢)								
	Winter	Super Off-Peak (35¢)						Off-Peak (36¢)									Peak (37¢)								
	March - April	Super Off-Peak (35¢)						Off-Peak (36¢)									Peak (37¢)								
Weekend	Summer	Super Off-Peak (29¢)												Peak (56¢)											
	Winter	Super Off-Peak (35¢)												Peak (37¢)											

⁴ Rates effective May 1, 2019, and do not reflect the baseline credit of approximately .10 cents kWh for usage up to 130% of baseline.

Figure 2-2: Default Pilot Rate 2

Day Type	Season	Hour Ending																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Weekday	Summer	Off-Peak (34¢)																Peak (53¢)							
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	Winter	Off-Peak (36¢)																Peak (37¢)							

Rate 1 is a three-period rate in summer and winter. Prices are the same on weekdays and weekends but weekends have a longer super off-peak period relative to weekdays. The peak period in both summer and winter is from 4 to 9 PM. The rate structure for winter is the same as summer except for the months of March and April where there is an additional super off-peak period from 10 AM to 2 PM. The peak-to-super-off-peak price ratio in summer is 1.9:1 for usage above the baseline quantity. In winter, the peak and off-peak prices are very similar, as super off-peak prices are nearly 6% lower than peak-period prices. The structure of Rate 2 is simpler compared to Rate 1 as there are only two rate periods that don't vary throughout the year or on weekdays or weekends. The peak period is the same as Rate 1 (4 PM to 9 PM) and the remaining period is an off-peak period from 9 PM to 4 PM.

Load impacts were estimated for three different climate regions in SDG&E's service territory (hot, moderate, and cool). For the moderate and cool climate regions, estimates were also made for two customer segments, CARE/FERA customers and non-CARE/FERA customers. CARE/FERA customers in the hot climate region were not allowed to be enrolled on TOU tariffs using default recruitment. As such, comparisons across the 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.

2.1 Evaluation Objectives

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

- Estimate hourly ex post load impacts for the summer period from June to October 2019;
- Forecast 2020-2030 D-TOU hourly ex ante load impacts for 1-in-2 and 1-in-10 year weather conditions by month – in the aggregate and per customer – for utility-specific and CAISO peak conditions;
- Estimate ex post and ex ante load reductions for each climate region (hot, moderate, and cool), pilot segment (non-CARE/FERA and CARE/FERA), and for net metered and non-net metered 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)⁵ and

⁵ California Public Utilities Commission Decision 08-04-050 issued on April 28, 2008 with Attachment A.

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).⁶

Based on pre-treatment validations it was determined that an error had occurred in the pilot implementation and the control groups were not statistically equivalent to the treatment groups. Without pre-treatment statistical equivalence between the treatment and control groups, the RED analysis framework was no longer valid. SDG&E selected a revised control group for each rate from the original pool of eligible customers. The revised control group for Rate 2 was statistically equivalent to the treatment group. However, the Rate 1 control group was not. As a result, statistical matching was implemented to select a revised control group for the Rate 1 population. Statistical matching involves selecting customers from a population of customers who were not subject to default notification that are most similar to the participant population based on observable variables (primarily load shape). The approach to selecting a matched control group is described in Section 3 of the Interim Report.

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 SDG&E TOU customers from the launch of the pilot through the end of October 2019.

After developing initial ex post load impacts for both rates, it became apparent that there was a significant influence from customers that were producing energy from installed solar systems during the middle of the day. These customers are known as being net energy metered (NEM). Given these differences, the decision was made to report ex post load impacts separately for NEM and non-NEM customers. For the analysis, NEM customers were limited to those who became NEM prior to 12 months before the beginning of the treatment period (since June 2017). Any participants who became NEM after this period were excluded from the ex post analysis altogether. This is discussed further in 3.1.3.

Additionally, due to the inherent difficulty in accounting for rolling NEM enrollments during the treatment period, as well as the inconsistent tracking of NEM transition dates, the NEM group

⁶ 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.

for the analysis was limited to those who had installed solar prior to one year before the treatment period began (NEM prior to June 2017). Customers who became NEM any time after June 2017 were removed from all analyses. Using these definitions, a new matched control group was formed for the NEM treatment customers using pre-treatment usage data and was carried through the ex post analysis.

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

2.3 Report Organization

The remainder of this report is organized as follows:

- Section 3 describes the methodology used to estimate ex post impacts;
- Section 4 presents post-enrollment opt-out rates;
- Sections 5 and 6 present ex post impacts and the persistence of load impacts;
- Section 7 presents ex ante estimates; and
- Section 8 present recommendations.

3 Methodology

This report provides ex post load impacts for the summer 2019 period (June 1, 2019 through October 31, 2019), and ex ante impacts for 1-in-2 and 1-in-10 year weather conditions for 2020 through 2030. The persistence of load impacts for customers who remained active accounts from the launch of the pilot through the end of October 2019 is also reported. Post-enrollment opt-out rates for each climate region and customer segment are also reported in Section 4. This section summarizes the methodological approaches used to estimate the metrics of interest for each customer segment. The discussion is organized into three broad sections summarizing the approach for estimating ex post load impacts, the persistence of load impacts, and ex ante load impacts.

3.1 Ex Post Load Impacts Methodology

The estimation of ex post load impacts by rate period and changes in daily energy use for each pilot rate are key pilot objectives. Also of interest is how load impacts vary across climate regions and customer segments (e.g., non-CARE/FERA customers and CARE/FERA customers) for two of the three climate regions, since CARE/FERA customers could not be defaulted in the hot climate region. The approaches used to estimate load impacts are summarized below.

3.1.1 Rate 1 Matched Control Group Methodology

The initial and revised control groups selected by SDG&E were not statistically equivalent to the Rate 1 treatment group during the pretreatment period. In order to have a valid comparison group for Rate 1, Nexant developed a matched control group using propensity score matching. In this procedure, a probit model is used to estimate a score for each customer based on a set of observable variables. A probit model is a regression model designed to estimate probabilities – in this case, the probability that a customer would be assigned to Rate 1 for the default TOU pilot. The propensity score can be thought of as a summary variable that includes all the relevant information in the observable variables about whether a customer would be part of the treatment group. Each customer in the Rate 1 population was matched with a customer in the eligible (but untreated) population that has the closest propensity score.

Nexant performed the match within specific customer segments: climate zone, CARE/FERA status, and My Account enrollment status. Because the hot climate zone segment is so small, it was not separated by CARE/FERA status or My Account enrollment status. A control group was developed for each season (summer and winter) and day type (average weekday, average weekend, and monthly system peak day). Matches were based on a set of variables that characterize load shape and the magnitude of electricity use on each day type for each season. Relevant variables include kW demand in the hours ending 4 AM, 8 AM, 12 PM, 4 PM, 8 PM, and 12 AM.

Each treatment customer on Rate 1 was matched to one control customer for each day type and season, but each control customer could be matched to multiple treatment customers. Load impacts for each segment were estimated using a difference-in-differences (DiD) methodology

following the completion and validation of the matching assignments. This method estimates impacts by subtracting treatment 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 inaccuracies in the matching algorithms.

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.⁷ Implementing a DiD through simple arithmetic would yield the same point estimate but it would not generate confidence intervals.

A typical regression specification for estimating impacts is shown below:

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

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 treat post term is the interaction of treat and post and its coefficient β is a difference-in-differences estimator of the treatment effect that makes use of the pretreatment data. The primary parameter of interest is β , which provides the estimated demand impact during the relevant period. The parameter 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.

3.1.2 Rate 2 Randomized Encouragement Design

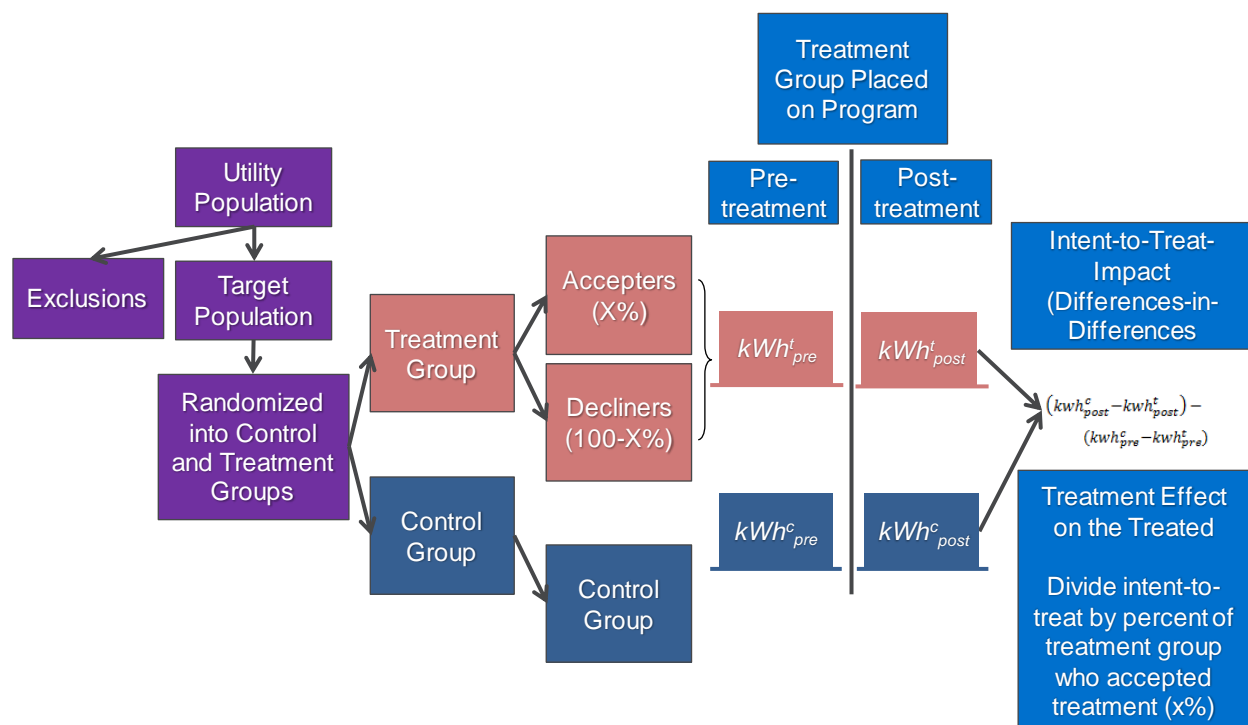
As discussed in Section 2, the pilot was designed as a randomized encouragement experimental design. Rate 1 was analyzed via a matched control group due to the pilot implementation challenges, but Rate 2 was analyzed as a RED. With a RED structure involving a single rate treatment of interest (for simplicity), 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

⁷ More accurately, they account for the correlation in regression errors within customers over time.

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).⁸ For Rate 2, the first stage ITT impact was estimated using the same DiD analysis used for Rate 1. A conceptual overview of the RED design and analysis for estimating load impacts is shown in Figure 3-1.

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



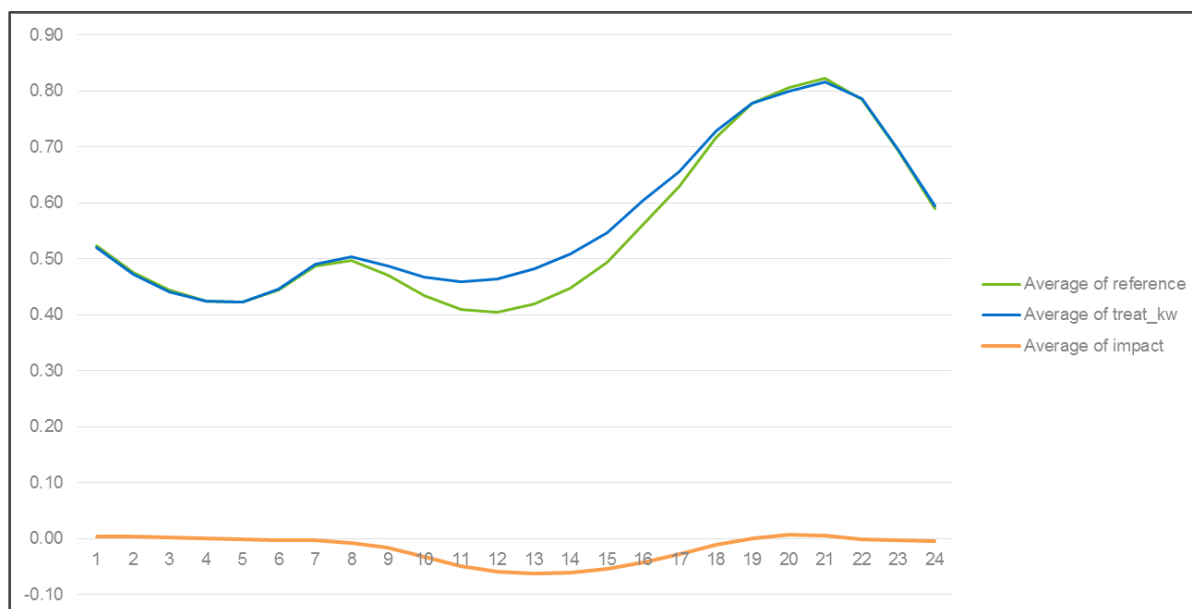
Customer attrition is an important factor to address in the load impact analysis. Customer attrition stems from four factors; customers who move (referred to as churn); customers who become ineligible after enrolling in the pilot; customers who opted out before the pilot began, and customers who dropped 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.

⁸ 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.

3.1.3 Net Energy Metering Customers

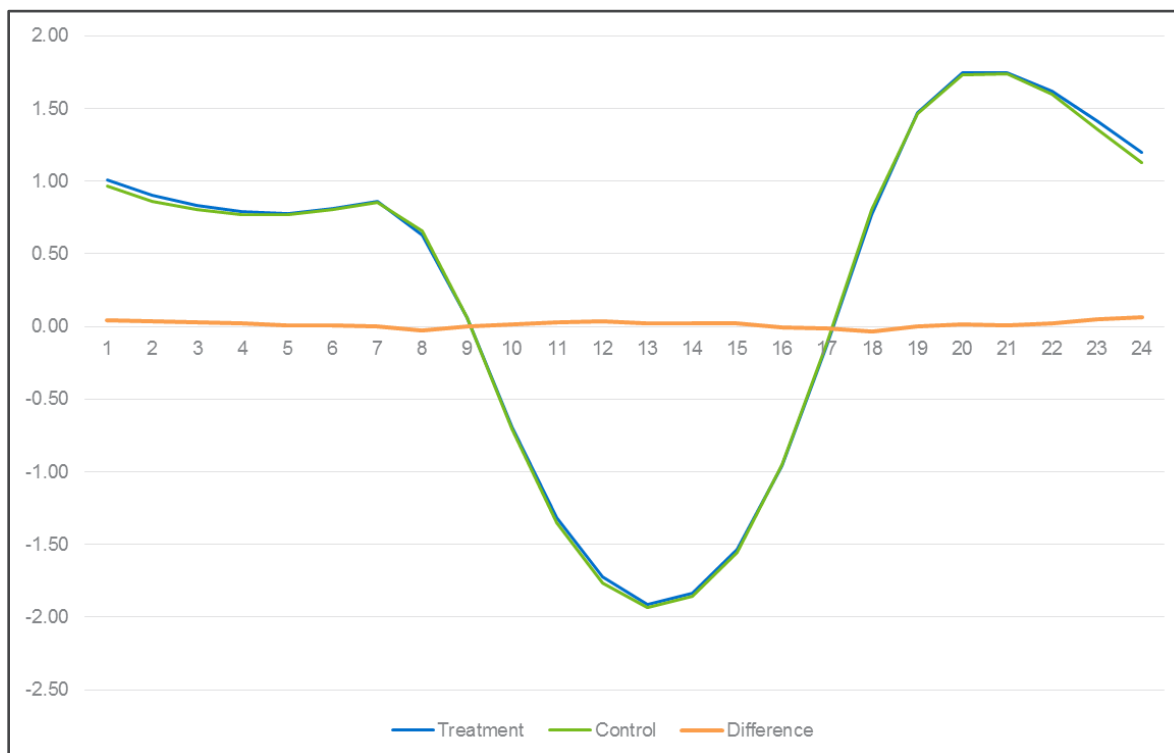
After developing initial ex post load impacts for both rates, it became apparent that there was a significant influence from customers that were producing energy from installed solar systems during the middle of the day. As seen in Figure 3-2, these net energy metered (NEM) customers were causing a significant drop in both the reference and treatment loads in the middle of the average weekday. Furthermore, there was a significant separation between the reference and treatment loads of a much larger magnitude than previously observed for TOU impacts, suggesting that matched treatment and control pairings had diverged in terms of becoming NEM at varying points throughout the pilot period.

Figure 3-2: Preliminary Rate 1 Ex Post Results – Average Weekday



Given these observed differences, the decision was made to report ex post load impacts separately for NEM and non-NEM customers. Additionally, due to the inherent difficulty in accounting for rolling NEM enrollments during the treatment period, as well as the inconsistent tracking of NEM transition dates, the NEM group for the analysis was limited to those who had installed solar prior to one year before the first summer of the pilot (NEM prior to June 2017). Customers who became NEM any time after June 2017 were removed from all analyses. This resulted in the exclusion of approximately 2,484 customers in Rate 1 and 2,269 customers in Rate 2 from the analysis. Using these definitions, a new matched control group was formed for the NEM treatment customers using pre-treatment usage data and was carried through the ex post analysis. Figure 3-3 shows the quality of the matching for these NEM customers. There is excellent agreement between the treatment and control loads in the pretreatment period, which improves the quality of the ex post impact estimation.

Figure 3-3: Average Weekday NEM Treatment and Control Loads during Pretreatment Period after Re-matching



3.1.4 Ex Post Load Impact Reporting

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.⁹ 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 monthly system peak days. Weather normalized results, such as those conducted for demand response ex ante load impacts, are not currently in scope for this evaluation. Load impacts are presented in both nominal (kWh) and proportional (%) terms.

⁹ http://www.calmac.org/events/FinalDecision_AttachmentA.pdf

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 independently by segment and climate region (for both treatment and control customers). These estimates are internally valid by virtue of the DiD analysis implemented in both the matched control group for Rate 1 and RED analysis for Rate 2.

3.2 Persistence of Load Impacts Methodology

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

As such, load impacts for the persistence analysis pertain to the population of customers that remained active SDG&E accounts over the entire period starting in April 2018 through the end of October 2019. The same methodology used to estimate ex post load impacts was used to estimate load impacts for this specific group of customers. Rate 1 customers who opted out or terminated their account are removed from the analysis dataset. For Rate 2, customers who opted out are retained in the analysis dataset to maintain the RED. The ITT adjustments are then updated using the persistent set of customers. While there is not a second winter for persistence comparison, the winter impacts for the subset of customers who were active for the full duration of the pilot are included with the two summer impacts to illustrate the relative differences in impacts between the summer and winter seasons for a common set of customers.

3.3 Ex Ante Load Impacts Methodology

Ex ante load impacts represent what the default TOU rates can deliver under a standardized set of weather conditions given changes in enrollment over the forecast horizon. The weather used for ex ante load impact estimation is meant to reflect under both normal (1-in-2 years) and extreme (1-in-10 years) weather. Ex ante impacts are reported for the Resource Adequacy (RA) window. The current RA window runs from 4 PM to 9 PM and is in effect during all months of the year.¹⁰ These are the same hours as the Rate 1 and Rate 2 peak period. However, because the TOU Off-Peak/Super Off-Peak hours are in effect for all hours outside of the RA window, ex ante estimates are established for these hours as well.

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

- First, ex post load impacts from November 2018 through October 2019 were developed using the fixed effects regression methodology described in Section 3.1;

¹⁰ 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 to 6 PM in the summer and 4 to 9 PM in the winter.

- Next, the relationship between ex post load impacts and temperature is estimated for each hour of the day, each season (summer/winter) and each rate (and for NEM and non-NEM separately for Rate1);
- Then, ex ante weather conditions are used as input to the regression models to predict impacts for each hour for the average weekday and monthly system peak days from January through December.

3.3.1 Estimating Ex Ante Weather Conditions

The CPUC Load Impact Protocols¹¹ (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. Nexant subsequently updated these weather conditions for SDG&E in 2017. The new ex ante weather dataset utilizes a shorter historical window of weather conditions that better reflect recent warming trends.

3.3.2 Estimating Ex Ante Load Impacts

Ex ante impact estimates were calculated by making predictions for ex ante weather conditions using a regression model of ex post impacts from 2018 and 2019. The ex ante model specification takes as its dependent variable the average hourly ex post impact for each week from November 2018 through October 2019. The independent variables for each hour were the average temperature from midnight to hour ending 17 (mean17) and a binary indicator for the calendar month. There is a positive relationship between temperature and load impacts; as temperatures rise, so do load impacts. The model specification is presented in Equation 3-1:¹²

Equation 3-1: Hourly Ex Ante Load Impact Model Specification

$$Impact_h = a + b \cdot mean17_h + \sum_{i=1}^{12} c_i \cdot month_{hi} + \epsilon$$

¹¹ See CPUC Rulemaking (R.) 07-01-041 Decision (D.) 08-04-050, "Adopting Protocols for Estimating Demand Response Load Impacts" and Attachment A, "Protocols."

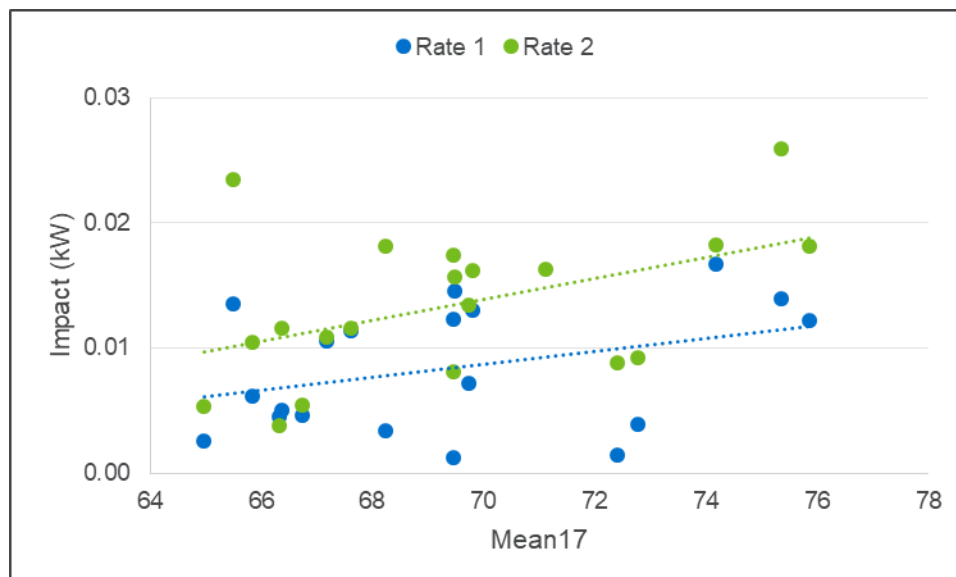
¹² Nexant has used similar model specifications in a number of load impact evaluations. It was originally chosen based on extensive validation analysis of many different model specifications conducted in conjunction with these prior evaluations.

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

Variable	Description
$Impact_h$	Per customer ex post load impact for each week, for the hour h
a	Estimated constant
b	Estimated parameter coefficient
c	Estimated parameter coefficient
$mean17_h$	Average temperature from midnight to hour ending 17
$month_{hi}$	A binary indicator for each month i of the year, January through December, for the hour h of interest
ε	The error term, 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 used 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 net metered and non-net metered customers and for each rate. Predictions from the model are then made separately for net metered and non-net metered customers and each rate's individual ex ante weather conditions.

Figure 3-4 illustrates the relationships between summer peak period temperatures and per customer load impacts for Rate 1 and Rate 2 customers. Similar relationships of ex post load impacts are estimated for each the winter season.

Figure 3-4: Peak Period Ex Post Impact versus Temperature – Rate 1 and Rate 2

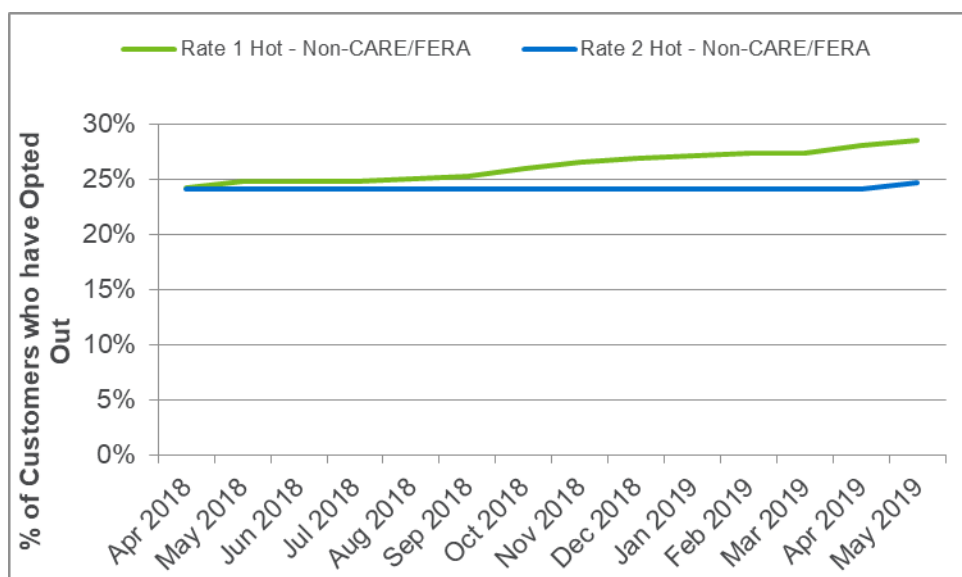
4 Customer Attrition

This section summarizes customer post-enrollment opt-out rates for each rate tested by SDG&E. 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.

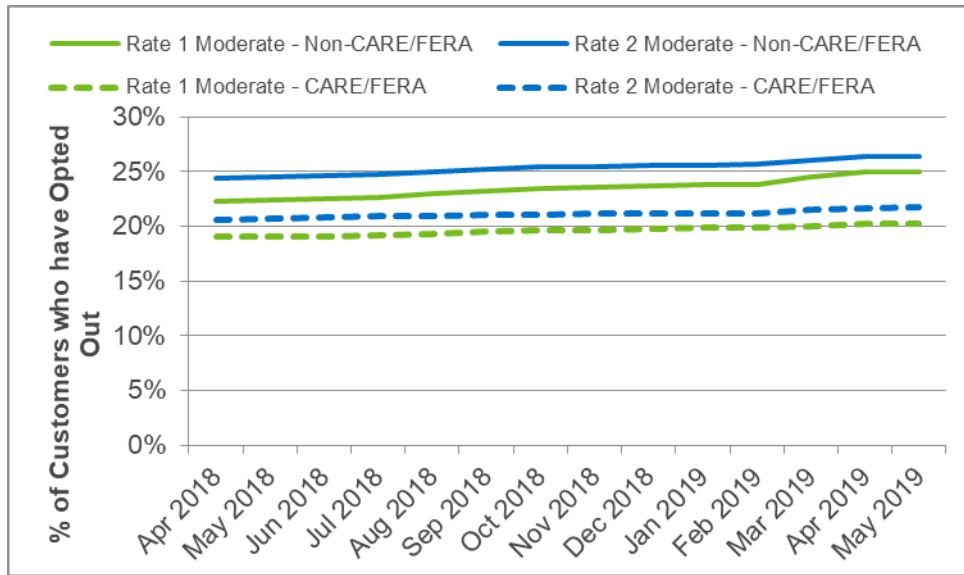
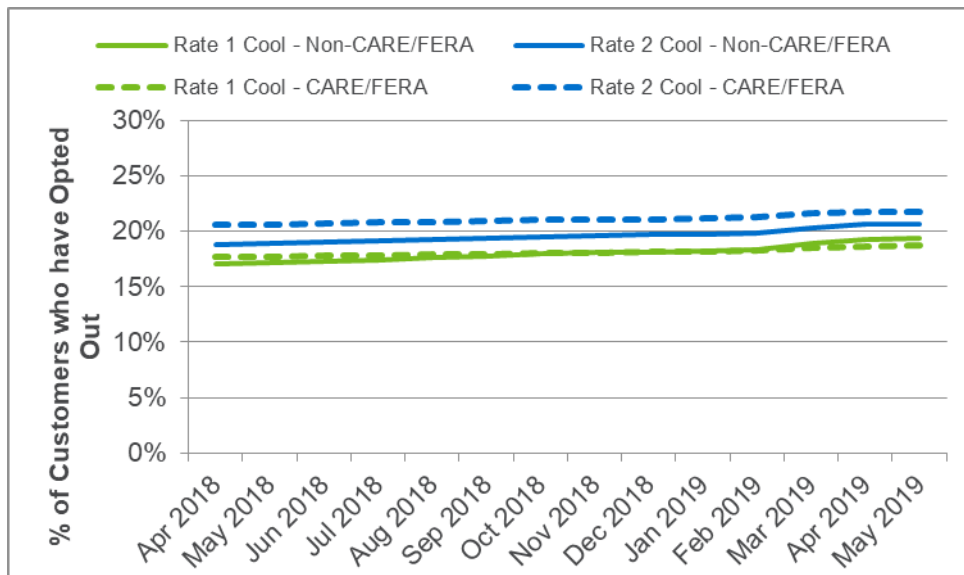
4.1 Post-enrollment Opt-Outs

Post-enrollment opt-out rates were very small during the period following enrollment through the end of the first summer (October 2018), and increased slightly throughout the winter months and second summer months. Cumulative opt-out rates are presented for the post-enrollment period for each climate region and CARE/FERA status in Figure 4-1 through 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 1.3% and 4.8%. Post enrollment opt-out rates are lowest in the cool climate region and highest in the hot region.

Figure 4-1: Cumulative Opt-Out Rates for Hot Climate Region¹³



¹³ Opt-out rates here present customers who opted out to the OAT, not those who opted out into the alternate rate.

Figure 4-2: Cumulative Opt-Out Rates for Moderate Climate Region**Figure 4-3: Cumulative Opt-Out Rates for Cool Climate Region**

5 Ex Post Load Impacts

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

- Rate 1:
 - Customers who were never net energy-metered (NEM) from 12 months before the onset of the pilot through September 2019, by climate region (hot, moderate, and cool) and CARE/FERA status, referred to as “non-NEM” customers. Throughout summer 2019, there was an average of 68,332 enrolled customers that fell into this category. After data cleaning, the final analysis used an average of 66,928 customers.
 - Customers who have been net energy-metered (NEM) since at least 12 months before the onset of the pilot, referred to as “NEM” customers. Throughout summer 2019, there was an average of 3,393 enrolled customers that fell into this category. After data cleaning and excluding customers that became NEM after 12 months before the onset of the pilot, the final analysis used an average of 903 customers.
- Rate 2:
 - Customers who were never net energy-metered (NEM) from 12 months before the onset of the pilot through September 2019, by climate region (hot, moderate, and cool) and CARE/FERA status, referred to as “non-NEM” customers. Throughout summer 2019, there was an average of 17,424 enrolled customers that fell into this category. After data cleaning, the final analysis used an average of 16,942 customers.
 - There were no Rate 2 NEM customers prior to the pilot launch. Approximately 2,269 Rate 2 customers transitioned to NEM during the pilot. The analysis of NEM customers in this evaluation is limited to customers who were NEM prior to the 12-month pre-treatment period. Accordingly, there are not any NEM customers included in the Rate 2 impact evaluation.

The pilot customers were segmented into those who were NEM at least 12 months before the onset of the pilot and those who were not. The ex post analysis focused on these two sets of customers. Those pilot participants who became NEM after the launch of the pilot are excluded from the analysis presented in this section. This resulted in the exclusion of approximately 2,484 customers in Rate 1 and 2,269 customers in Rate 2 from the analysis. See Section 3.1.3 for additional details.

As discussed in Section 3.1.2 and Section 4, customer attrition is an important factor to address in the load impact analysis. Customers who moved, became ineligible after enrolling in the pilot, opted out before the pilot began, or dropped off the rate after enrollment are removed from the analysis. During the first summer, the average number of eligible customers for the analysis was

88,169 for Rate 1 and 20,781 for Rate 2. For the current analysis, after including the additional exclusion of the NEM enrollments after the pre-treatment period, the average number of customers included in the analysis was 67,831 for Rate 1 and 16,942 for Rate 2.

It is also imperative that comparisons across climate regions are cognizant of the differences in the mix of customers across regions. That is, because CARE/FERA customers are not included in the hot climate region, comparisons of load impacts across the 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 hot region. Similarly, comparisons across customer segments for the service territory as a whole do not just reflect differences in behavior between CARE/FERA and non-CARE/FERA customers but also differences in the mix of customers across climate regions. Therefore, it is not appropriate to claim that differences between CARE/FERA and non-CARE/FERA customers at the service territory level accurately reflects a difference in behavior between the two groups of customers, all other factors held constant.

Load impacts are reported here for each rate period for the average weekday, average weekend, and the average monthly peak day for the summer months of June through October. Impacts are reported for each rate, customer segment, and climate region 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 tables for SDG&E Rate 1 for all eligible customers in the service territory. Pull down menus in the upper left hand corner allow users to select different climate regions, day types (e.g., weekdays, weekends, monthly peak day) and time period (individual months or the average of June through October). 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.

Figure 5-1: Example of Content of Electronic Tables Underlying Load Impacts Summarized in this Report (SDG&E Rate 1, Average Summer 2019 Weekday, All Non-NEM Customers)

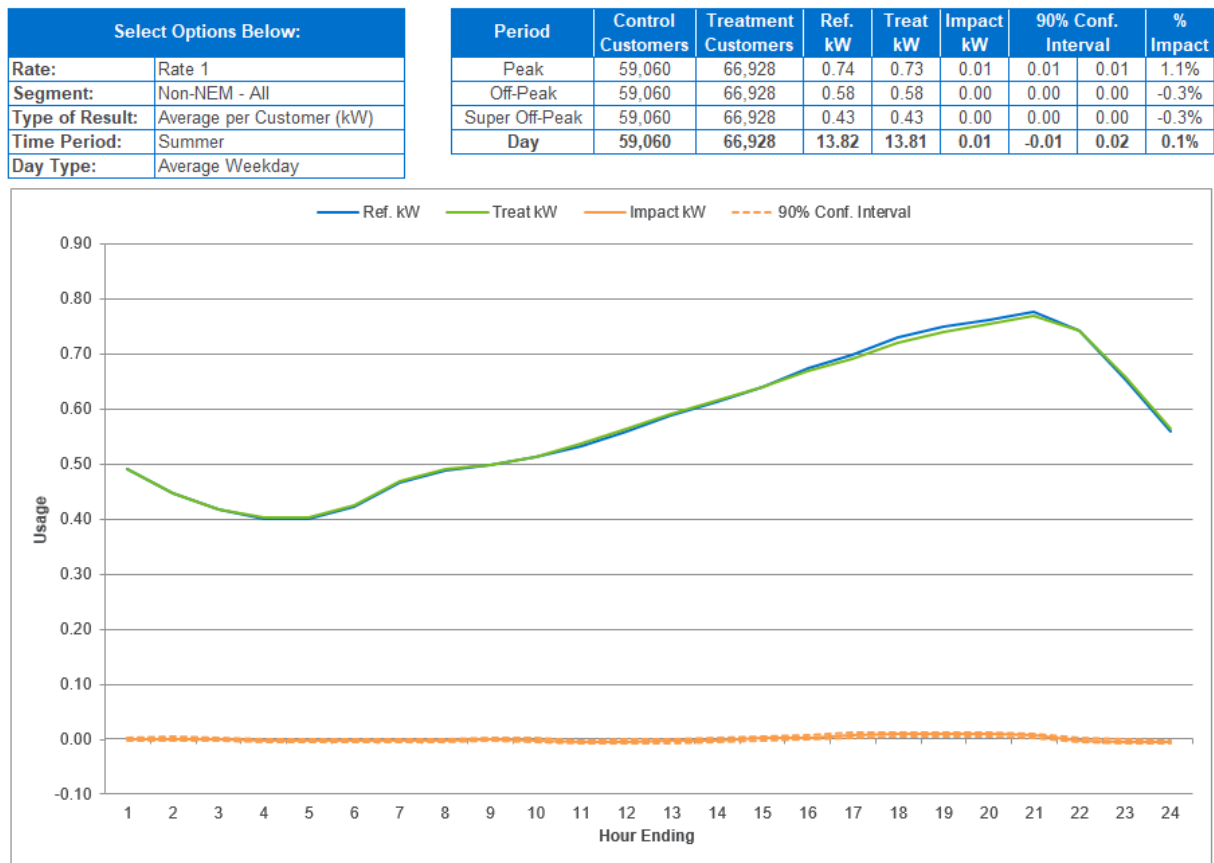


Figure 5-1 (Continued): Example of Content of Electronic Tables Underlying Load Impacts Summarized in this Report (SDG&E Rate 1, Average Summer 2019 Weekday, All Non-NEM Customers)

Hour	Period	Ref. kW	Treat kW	Impact kW	% Impact	Weighted Temp. (°F)	Uncertainty-adjusted Impact - Percentiles				
							10th	30th	50th	70th	90th
1	Super Off-Peak	0.49	0.49	0.00	0.1%	65.0	0.00	0.00	0.00	0.00	0.00
2	Super Off-Peak	0.45	0.45	0.00	0.1%	64.6	0.00	0.00	0.00	0.00	0.00
3	Super Off-Peak	0.42	0.42	0.00	-0.2%	64.2	0.00	0.00	0.00	0.00	0.00
4	Super Off-Peak	0.40	0.40	0.00	-0.5%	63.8	0.00	0.00	0.00	0.00	0.00
5	Super Off-Peak	0.40	0.40	0.00	-0.8%	63.4	-0.01	0.00	0.00	0.00	0.00
6	Super Off-Peak	0.42	0.43	0.00	-0.8%	63.2	-0.01	0.00	0.00	0.00	0.00
7	Off-Peak	0.47	0.47	0.00	-0.7%	63.0	-0.01	0.00	0.00	0.00	0.00
8	Off-Peak	0.49	0.49	0.00	-0.4%	63.3	0.00	0.00	0.00	0.00	0.00
9	Off-Peak	0.50	0.50	0.00	0.1%	65.3	0.00	0.00	0.00	0.00	0.00
10	Off-Peak	0.51	0.51	0.00	-0.2%	68.6	0.00	0.00	0.00	0.00	0.00
11	Off-Peak	0.53	0.54	0.00	-0.8%	72.0	-0.01	-0.01	0.00	0.00	0.00
12	Off-Peak	0.56	0.56	0.00	-0.7%	74.9	-0.01	-0.01	0.00	0.00	0.00
13	Off-Peak	0.59	0.59	0.00	-0.6%	76.5	-0.01	0.00	0.00	0.00	0.00
14	Off-Peak	0.61	0.61	0.00	-0.3%	77.3	0.00	0.00	0.00	0.00	0.00
15	Off-Peak	0.64	0.64	0.00	0.2%	77.5	0.00	0.00	0.00	0.00	0.00
16	Off-Peak	0.67	0.67	0.00	0.5%	77.3	0.00	0.00	0.00	0.00	0.01
17	Peak	0.70	0.69	0.01	1.1%	76.5	0.00	0.01	0.01	0.01	0.01
18	Peak	0.73	0.72	0.01	1.2%	75.1	0.01	0.01	0.01	0.01	0.01
19	Peak	0.75	0.74	0.01	1.2%	73.2	0.01	0.01	0.01	0.01	0.01
20	Peak	0.76	0.75	0.01	1.2%	70.6	0.01	0.01	0.01	0.01	0.01
21	Peak	0.78	0.77	0.01	0.8%	68.3	0.00	0.01	0.01	0.01	0.01
22	Off-Peak	0.74	0.74	0.00	-0.2%	67.0	0.00	0.00	0.00	0.00	0.00
23	Off-Peak	0.66	0.66	0.00	-0.6%	66.1	-0.01	0.00	0.00	0.00	0.00
24	Off-Peak	0.56	0.56	0.00	-0.9%	65.5	-0.01	-0.01	0.00	0.00	0.00

The remainder of this section is organized by rate treatment—that is, load impacts are presented for each relevant customer segment and climate region for each of the two rates. Finally, comparisons of load impacts across the two TOU rates are made for the peak period from 4 to 9 PM and for the average weekday as a whole.

5.1 Summary of Pilot Rates

Figure 2-1 and Figure 2-2 in Section 2 summarized the rate periods and prices for Rates 1 and 2. Importantly, the prices shown in those figures and discussed below do not reflect the baseline credit of 10¢/kWh that applies to each rate for usage below 130% of the baseline quantity.

Rate 1 has three rate periods on summer and winter weekdays. The peak period on Rate 1 is the same all year long and runs from 4 PM to 9 PM on weekdays and weekends. The off-peak and super off-peak periods are the same all year as well. On weekdays, the off-peak (or shoulder) period runs from 6 AM to 4 PM and 9 PM to midnight and the super off-peak period lasts from midnight to 6 AM. The peak to super off-peak price ratio (ignoring the baseline credit) is 1.9 to 1 in summer and the peak to super off-peak ratio is 1.1 to 1 in winter. The months of March and April have an additional super off-peak period from 10 AM to 2 PM.

The peak period for average weekends is the same as on weekdays (4 PM to 9 PM). The super off-peak period is longer for average weekends as it extends from 12 AM to 2 PM and that leaves the remaining time periods of 2 PM to 4 PM and 9 PM to 12 AM as off-peak periods.

SDG&E's Rate 2 rate structure is simpler than Rate 1 as it has two rate periods for average weekdays and average weekends during the summer and winter seasons. Rate 2 has the same peak period duration as Rate 1, from 4 PM to 9 PM, but it has a slightly lower peak price in summer months (53¢/kWh for Rate 2 versus 56¢/kWh for Rate 1) and the same peak price in winter months (37¢/). The off-peak price for Rate 2 is 34¢/kWh during the summer months which represents a peak to off-peak price ratio of 1.6 to 1. The winter season for both rates runs from is November 1 through May 31.

5.2 Rate 1

This section presents load impacts for Rate 1 TOU customers who never became NEM during the pilot period, as well as load impacts for customers who had become NEM prior to 12 months before the pilot period began. Load impacts are presented at the overall level, as well as by climate region and CARE/FERA status.

5.2.1 Load Impacts for Non-NEM Customers by Pilot Segment

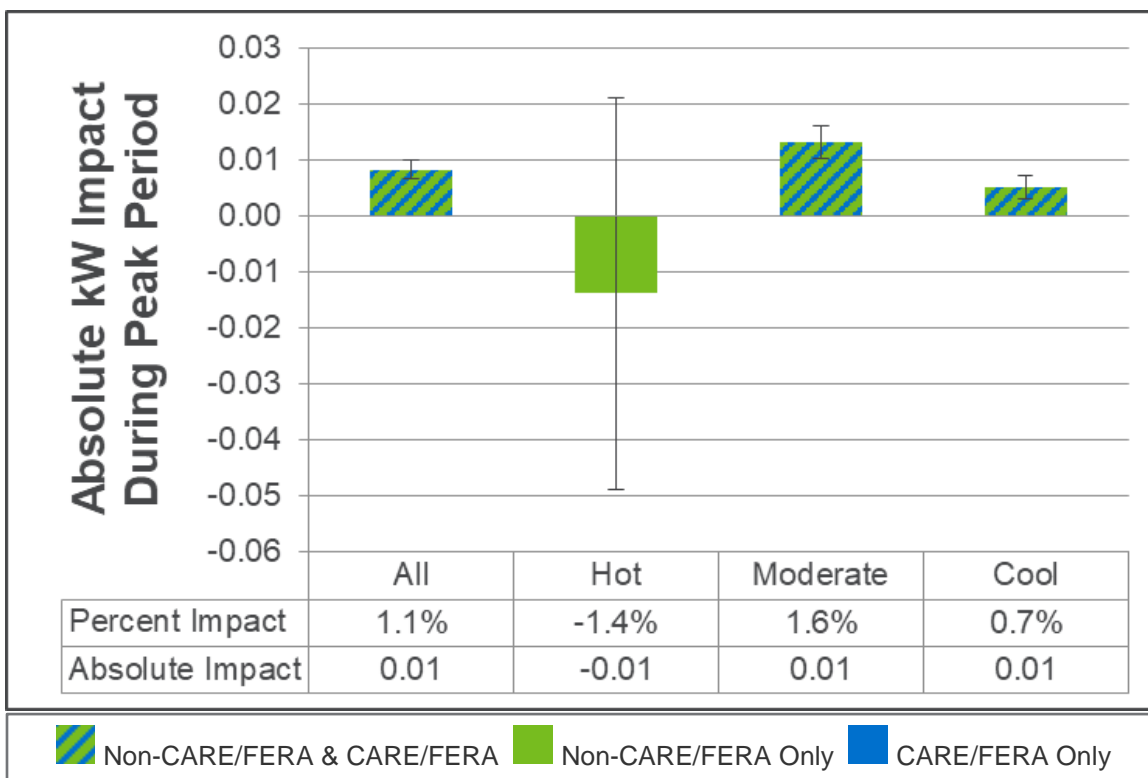
Figure 5-2 shows the average peak-period load reduction in absolute terms for Rate 1 for non-net metered customers in SDG&E's service territory as a whole and for each climate region. The lines bisecting the top of each bar in the figures show the 90% confidence band for each estimate. If the confidence band includes 0, it means that the estimated load impact is not statistically different from 0 at the 90% level of confidence. If the confidence bands for two bars do not overlap, it means 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.¹⁴ In these cases, t-tests were calculated to determine whether the difference is statistically significant.¹⁵

Bars with blue and green stripes indicate that the segment includes a combination of CARE/FERA customers and non-CARE/FERA customers, while solid green bars represent segments that are non-CARE/FERA only. Solid blue bars represent segments that are CARE/FERA customers only. However, it is important to note that the "All" category includes non-CARE/FERA customers from all climate regions but CARE/FERA customers only from the moderate and cool climate regions. As a result, the "All" estimates cannot be directly compared to the "Moderate" and "Cool" estimates.

¹⁴ For further discussion of this topic, see <https://www.cscu.cornell.edu/news/statnews/stnews73.pdf>.

¹⁵ The test was applied at the 90% confidence level which means that a t-value exceeding 1.65 indicates statistical significance.

Figure 5-2: Average Peak Period Load Impacts for SDG&E Rate 1 by Climate Region
(Positive values represent load reductions)



As seen in Figure 5-2, the average peak-period load impacts for the service territory as a whole and for the moderate and cool climate regions are statistically significant at the 90% level of confidence. On average, default pilot participants across SDG&E's service territory on Rate 1 reduced peak-period electricity use by 1.1%, or 0.01 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 1.6% and 0.01 kW in the moderate climate region to a low of about 0.7% and 0.01 kW in the cool climate region. Customers in the hot climate region showed peak period load increases, but the impact was not statistically significant at the 90% confidence level.

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

Table 5-1: Average Hourly Load Impacts by Climate Region, Rate Period and Day Type for SDG&E Rate 1 – Non-NEM
(Positive values represent load reductions, negative values represent load increases)

Rate 1														
Day Type	Period	Hours	All			Hot			Moderate			Cool		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	0.74	0.01	1.1%	1.03	-0.01	-1.4%	0.83	0.01	1.6%	0.69	0.01	0.7%
	Off-Peak	6 AM to 4 PM and 9 PM to 12 AM	0.58	>-0.01	-0.3%	0.77	-0.01	-1.6%	0.63	>-0.01	-0.1%	0.55	>-0.01	-0.5%
	Super Off-Peak	12 AM to 6 AM	0.43	>-0.01	-0.3%	0.49	0.01	1.8%	0.45	>-0.01	-0.3%	0.41	>-0.01	-0.4%
	Day	All Hours	0.58	<0.01	0.1%	0.75	-0.01	-0.9%	0.62	<0.01	0.3%	0.54	>-0.01	-0.1%
Average Weekend	Peak	4 PM to 9 PM	0.76	0.01	0.9%	1.05	<0.01	0.1%	0.84	0.01	1.5%	0.71	<0.01	0.5%
	Off-Peak	2 PM to 4 PM and 9 PM to 12 AM	0.68	>-0.01	-0.3%	0.86	-0.01	-1.2%	0.75	>-0.01	-0.2%	0.64	>-0.01	-0.3%
	Super Off-Peak	12 AM to 2 PM	0.51	>-0.01	-0.7%	0.65	-0.01	-1.4%	0.54	>-0.01	-0.5%	0.49	>-0.01	-0.8%
	Day	All Hours	0.60	>-0.01	-0.2%	0.78	-0.01	-0.9%	0.65	<0.01	0.1%	0.57	>-0.01	-0.3%
Monthly System Peak	Peak	4 PM to 9 PM	0.99	0.02	2.1%	1.30	0.02	1.2%	1.15	0.03	2.8%	0.89	0.01	1.5%
	Off-Peak	6 AM to 4 PM and 9 PM to 12 AM	0.72	>-0.01	0.0%	0.92	0.02	2.0%	0.80	<0.01	0.2%	0.66	>-0.01	-0.2%
	Super Off-Peak	12 AM to 6 AM	0.49	>-0.01	-0.5%	0.58	0.03	4.5%	0.53	-0.01	-1.0%	0.47	>-0.01	-0.2%
	Day	All Hours	0.72	<0.01	0.5%	0.91	0.02	2.2%	0.81	0.01	0.8%	0.66	<0.01	0.2%

* A shaded cell indicates estimate is not statistically significant

The reference loads shown in Table 5-1 represent estimates of what customers on the TOU rate would have used if they had not responded to the price signals contained in the TOU tariff. As seen in the table, average hourly usage during the peak period is roughly 0.74 kW for the SDG&E territory as a whole, and around 0.58 kW for the 24 hour average weekday. In the hot climate region the average usage during the peak period is higher (1.03 kW) than in the moderate climate region (0.83 kW) or cool climate region (0.69 kW). However, the cool and moderate climate regions include CARE/FERA customers while the hot climate region does not.

The monthly system peak day estimates represent the average across the five weekdays, one in each summer month, when SDG&E's system peaked in 2019. Peak period reference loads are higher on these days than on the average weekday. In all climate regions, both the percent and absolute impacts were largest on the average monthly system peak day.

As seen in Table 5-1, peak-period load reductions were statistically significant for all climate regions and day types, except for those associated with the hot climate region. In the off-peak (or shoulder) period, which varied in timing and length between weekdays and weekends, load reductions were essentially nonexistent in all climate regions and day types. However, the overall and cool climate regions produced statistically significant load increases on the average weekday. In the super off-peak period, which runs from midnight to 6 AM, for the overall and cool climate regions, there were also statistically significant load increases on both the average weekday and average weekend. For non-NEM customers in SDG&E service territory, there was no statistically significant increase or decrease in daily electricity use on the average weekday.

Figure 5-3 shows the absolute-peak period load impacts for Rate 1 for non-NEM CARE/FERA and non-CARE/FERA customers for the service territory as a whole and for each climate region. Non-CARE/FERA segments are shaded in green while CARE/FERA segments are shaded in blue. In the combined regions and in the moderate and cool regions, both the percent and

absolute load impacts were greater for non-CARE/FERA customers than for CARE/FERA and the differences were statistically significant. The greatest load reductions came from non-CARE/FERA customers in the moderate climate region, at 1.7% and 0.01 kW. The smallest load reductions in turn are from the non-CARE/FERA customers in the hot climate region with -1.4% and -0.01 kW (this impact was not statistically significant).

Figure 5-3: Average Peak Period Impacts for SDG&E Rate 1 by Climate Region & CARE/FERA Status – Non-NEM
(Positive values represent load reductions)

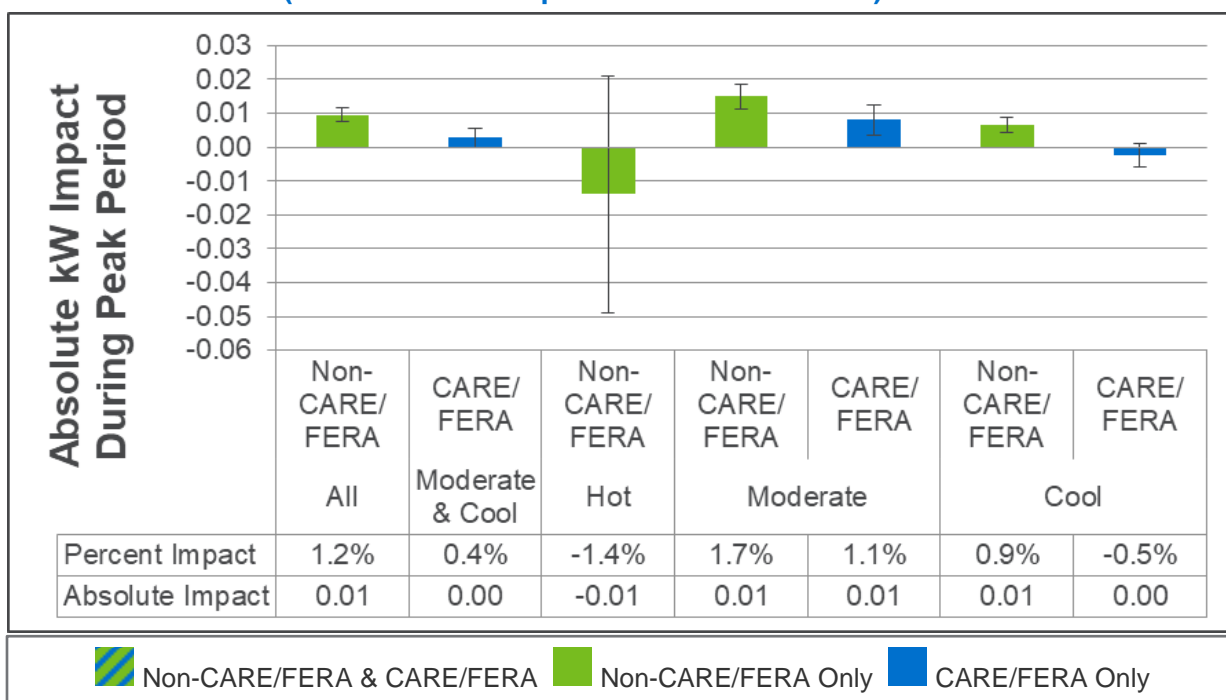


Table 5-2 shows the estimated load impacts for each rate period and day type for the service territory as a whole and by climate region for non-CARE/FERA customers and Table 5-3 shows the impacts for CARE/FERA customers. The hot climate region in Table 5-3 displays N/A values as there are no CARE/FERA customers in the hot region.

For the moderate and cool climate regions, non-CARE/FERA customers have greater peak-period demand than CARE/FERA customers. For example, on the average weekday in the moderate and cool climate regions, peak period demand is equal to 0.86 kW and 0.72 kW for non-CARE/FERA customers and 0.71 kW and 0.52 kW for CARE/FERA customers, respectively.

CARE/FERA and non-CARE/FERA customers both showed mostly statistically significant load reductions during peak periods across the territory as a whole and in each climate region on the average weekday, average weekend, and monthly system peak. The exceptions were for CARE/FERA customers in the combined moderate and cool climate zone on the average weekday, CARE/FERA customers in the cool climate zone on the average weekday and average weekend, and non-CARE/FERA customers in the hot climate region for all day types.

CARE/FERA customers in the default pilot population showed small but statistically significant increases in off-peak demand on weekdays and super off-peak demand on weekends.

Table 5-2: Average Hourly Load Impacts by Rate Period and Day Type for SDG&E Rate 1 by Climate Region – Non-CARE/FERA
(Positive values represent load reductions, negative values represent load increases)

Rate 1														
Day Type	Period	Hours	All - Non-CARE/FERA			Hot - Non-CARE/FERA			Moderate - Non-CARE/FERA			Cool - Non-CARE/FERA		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	0.77	0.01	1.2%	1.03	-0.01	-1.4%	0.86	0.01	1.7%	0.72	0.01	0.9%
	Off-Peak	6 AM to 4 PM and 9 PM to 12 AM	0.60	>-0.01	-0.2%	0.77	-0.01	-1.6%	0.65	>-0.01	0.0%	0.57	>-0.01	-0.3%
	Super Off-Peak	12 AM to 6 AM	0.45	>-0.01	-0.2%	0.49	0.01	1.8%	0.47	>-0.01	-0.2%	0.43	>-0.01	-0.3%
	Day	All Hours	0.60	<0.01	0.2%	0.75	-0.01	-0.9%	0.65	<0.01	0.4%	0.57	>-0.01	0.0%
Average Weekend	Peak	4 PM to 9 PM	0.80	0.01	1.0%	1.05	<0.01	0.1%	0.88	0.02	1.8%	0.74	<0.01	0.5%
	Off-Peak	2 PM to 4 PM and 9 PM to 12 AM	0.71	>-0.01	-0.2%	0.86	-0.01	-1.2%	0.78	>-0.01	-0.1%	0.67	>-0.01	-0.3%
	Super Off-Peak	12 AM to 2 PM	0.54	>-0.01	-0.7%	0.65	-0.01	-1.4%	0.57	>-0.01	-0.6%	0.52	>-0.01	-0.7%
	Day	All Hours	0.63	>-0.01	-0.1%	0.78	-0.01	-0.9%	0.68	<0.01	0.2%	0.59	>-0.01	-0.3%
Monthly System Peak	Peak	4 PM to 9 PM	1.04	0.02	2.2%	1.30	0.02	1.2%	1.21	0.04	3.2%	0.94	0.01	1.5%
	Off-Peak	6 AM to 4 PM and 9 PM to 12 AM	0.75	<0.01	0.1%	0.92	0.02	2.0%	0.84	<0.01	0.4%	0.70	>-0.01	-0.2%
	Super Off-Peak	12 AM to 6 AM	0.51	>-0.01	-0.4%	0.58	0.03	4.5%	0.55	-0.01	-1.0%	0.49	>-0.01	0.0%
	Day	All Hours	0.75	<0.01	0.6%	0.91	0.02	2.2%	0.84	0.01	1.0%	0.70	<0.01	0.3%

* A shaded cell indicates estimate is not statistically significant

Table 5-3: Average Hourly Load Impacts by Rate Period and Day Type for SDG&E Rate 1 by Climate Region – CARE/FERA
(Positive values represent load reductions, negative values represent load increases)

Rate 1														
Day Type	Period	Hours	Moderate & Cool - CARE/FERA			Hot - CARE/FERA			Moderate - CARE/FERA			Cool - CARE/FERA		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	0.61	<0.01	0.4%	N/A	N/A	N/A	0.71	0.01	1.1%	0.52	>-0.01	-0.5%
	Off-Peak	6 AM to 4 PM and 9 PM to 12 AM	0.47	>-0.01	-0.8%	N/A	N/A	N/A	0.53	>-0.01	-0.3%	0.41	-0.01	-1.5%
	Super Off-Peak	12 AM to 6 AM	0.35	>-0.01	-0.8%	N/A	N/A	N/A	0.39	>-0.01	-0.5%	0.32	>-0.01	-1.2%
	Day	All Hours	0.47	>-0.01	-0.5%	N/A	N/A	N/A	0.53	<0.01	0.1%	0.41	>-0.01	-1.1%
Average Weekend	Peak	4 PM to 9 PM	0.61	<0.01	0.5%	N/A	N/A	N/A	0.69	<0.01	0.4%	0.52	<0.01	0.6%
	Off-Peak	2 PM to 4 PM and 9 PM to 12 AM	0.56	>-0.01	-0.7%	N/A	N/A	N/A	0.63	-0.01	-0.8%	0.49	>-0.01	-0.5%
	Super Off-Peak	12 AM to 2 PM	0.41	>-0.01	-0.7%	N/A	N/A	N/A	0.46	>-0.01	-0.4%	0.37	>-0.01	-1.1%
	Day	All Hours	0.48	>-0.01	-0.4%	N/A	N/A	N/A	0.54	>-0.01	-0.3%	0.43	>-0.01	-0.5%
Monthly System Peak	Peak	4 PM to 9 PM	0.78	0.01	1.7%	N/A	N/A	N/A	0.95	0.02	1.7%	0.64	0.01	1.7%
	Off-Peak	6 AM to 4 PM and 9 PM to 12 AM	0.57	>-0.01	-0.4%	N/A	N/A	N/A	0.68	>-0.01	-0.5%	0.48	>-0.01	-0.3%
	Super Off-Peak	12 AM to 6 AM	0.41	>-0.01	-1.2%	N/A	N/A	N/A	0.47	>-0.01	-0.8%	0.36	-0.01	-1.7%
	Day	All Hours	0.58	<0.01	0.1%	N/A	N/A	N/A	0.68	<0.01	0.1%	0.48	<0.01	0.0%

* A shaded cell indicates estimate is not statistically significant

5.2.2 Load Impacts for NEM Customers

For this analysis, NEM customers are defined to be customers who were net metered prior to 12 months from before the beginning of the pilot (June 2017) through the end of the second summer (October 2019). Customers who became net metered during the pilot are excluded from the analysis presented here. Figure 5-4 presents average summer weekday peak period load reductions for net metered (NEM) customers. These NEM customers showed small load increases of 0.01 kW (0.6%). However, due to the small sample size (approximately 900 customers), the negative impacts are not statistically significant. Figure 5-4 also presents estimates for load impacts for the combined group of NEM and non-NEM customers, based on a weighted average of the two groups' impacts using the population proportion of NEM customers.

Figure 5-4: Average Peak Period Load Impacts for SDG&E Rate 1 by NEM Status
(Positive values represent load reductions)

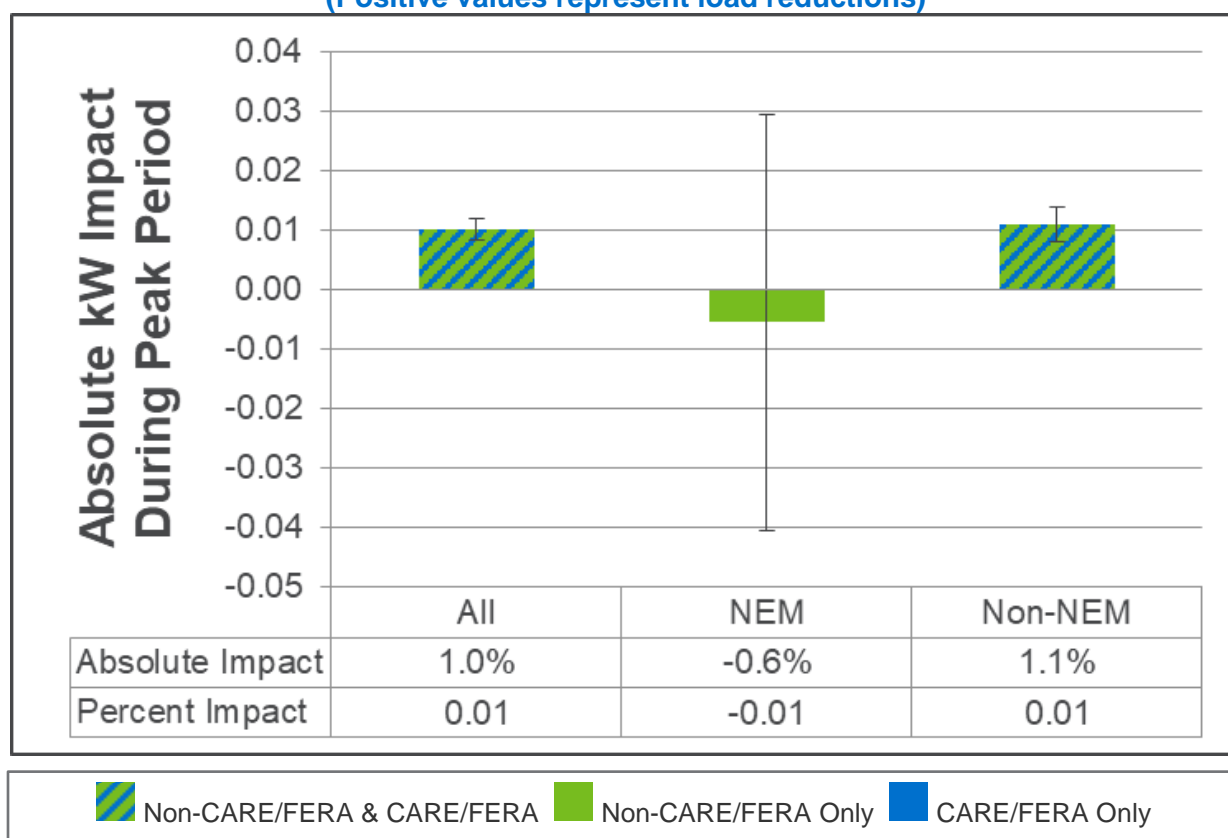
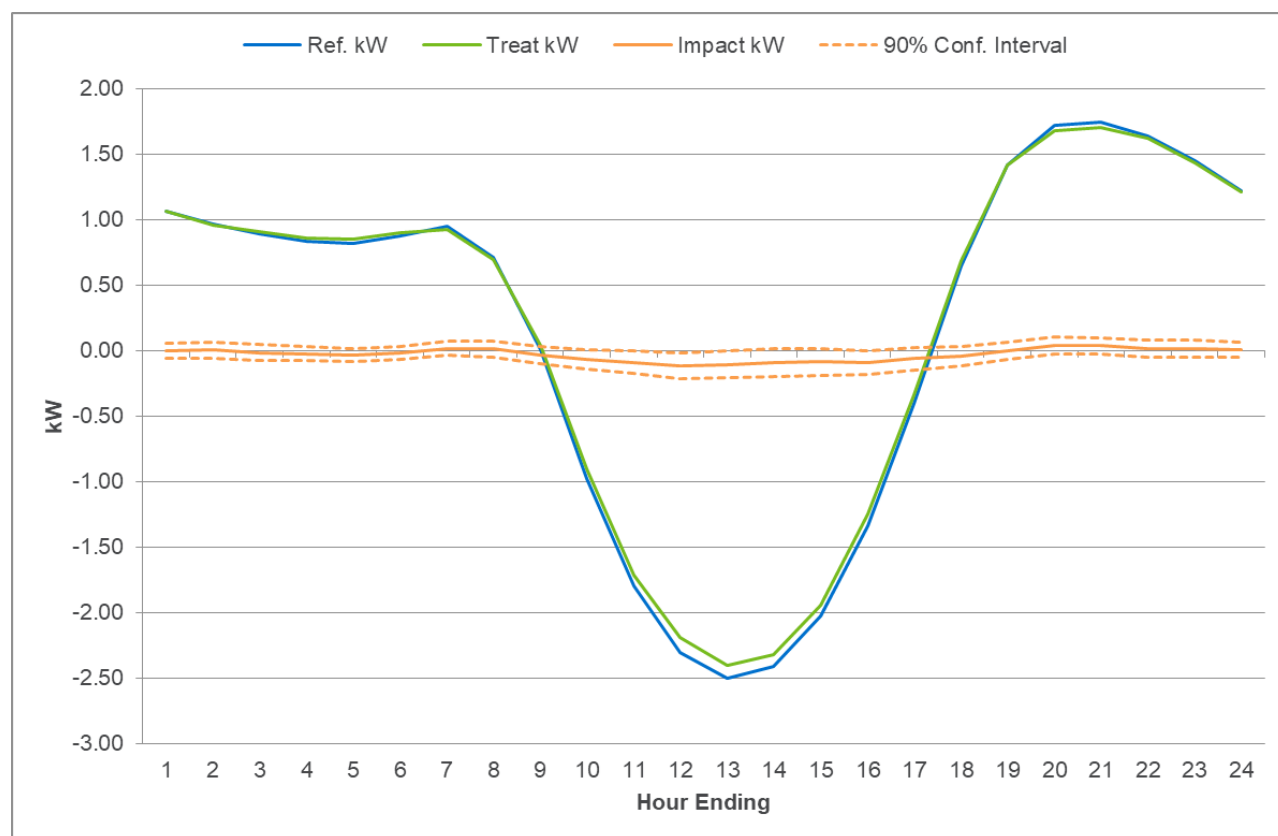


Figure 5-5 shows the daily reference and treatment loads for Rate 1 NEM customers on the average weekday during summer 2019. Treatment customers show slightly higher usage during the middle of the day when solar generation is at its highest. This effect persists into the first two hours of the peak period (hours ending 17 and 18), leading to slightly negative load impacts of -0.05 kW before transitioning to positive load impacts of 0.03 kW for the remaining three hours of the period.

Figure 5-5: Average Weekday Summer Daily Load Impacts for SDG&E Rate 1 - NEM

5.3 Rate 2

This section presents load impacts for Rate 2 TOU customers who never became NEM during the pilot period. There were no Rate 2 customers that were net energy metered since 12 months prior to the beginning of the pilot, so this section presents load impacts for the non-NEM customers, which effectively comprise the entire Rate 2 population for the purposes of this analysis. Unlike Rate 1, NEM customers were not included in the initial Rate 2 population. Load impacts are presented at the overall level, as well as by climate region and CARE/FERA status.

5.3.1 Load Impacts for Non-NEM Customers by Pilot Segment

SDG&E's Rate 2 differs from Rate 1 as it is a two-period rate, rather than a three-period rate. Like Rate 1, the peak period is from 4 PM to 9 PM on weekdays and weekends. In summer, for electricity usage above 130% of the baseline quantity, prices equal 53 ¢/kWh in the peak period and 34 ¢/kWh in the off-peak period. Like Rate 1, a credit of 10 ¢/kWh is applied to usage below 130% of the baseline quantity.

Figure 5-6 shows the absolute load impacts for the weekday peak period for Rate 2 for SDG&E's service territory as a whole and for each climate region. The load reductions for the SDG&E territory as a whole, 1.8% or 0.01 kW, are larger than those for Rate 1 (1.1% or 0.01 kW) and the difference in both absolute and percentage terms is statistically significant. This was the same trend observed in the first summer of the pilot in 2018. The average hourly peak-

period load reductions are statistically significant in both absolute and percentage terms. Customers in the hot climate region had the largest peak period load impacts of 4.2% or 0.04 kW. However, impacts in the hot climate region are not statistically significantly greater than those in the cool and moderate climate regions. The load impacts in the moderate and cool climate regions were both statistically significant. The moderate climate region showed impacts equal to about 2.5% or 0.02 kW, while the cool climate region showed 1.2% or 0.01 kW.

Figure 5-6: Average Peak Period Load Impacts for SDG&E Rate 2 by Climate Region
(Positive values represent load reductions)

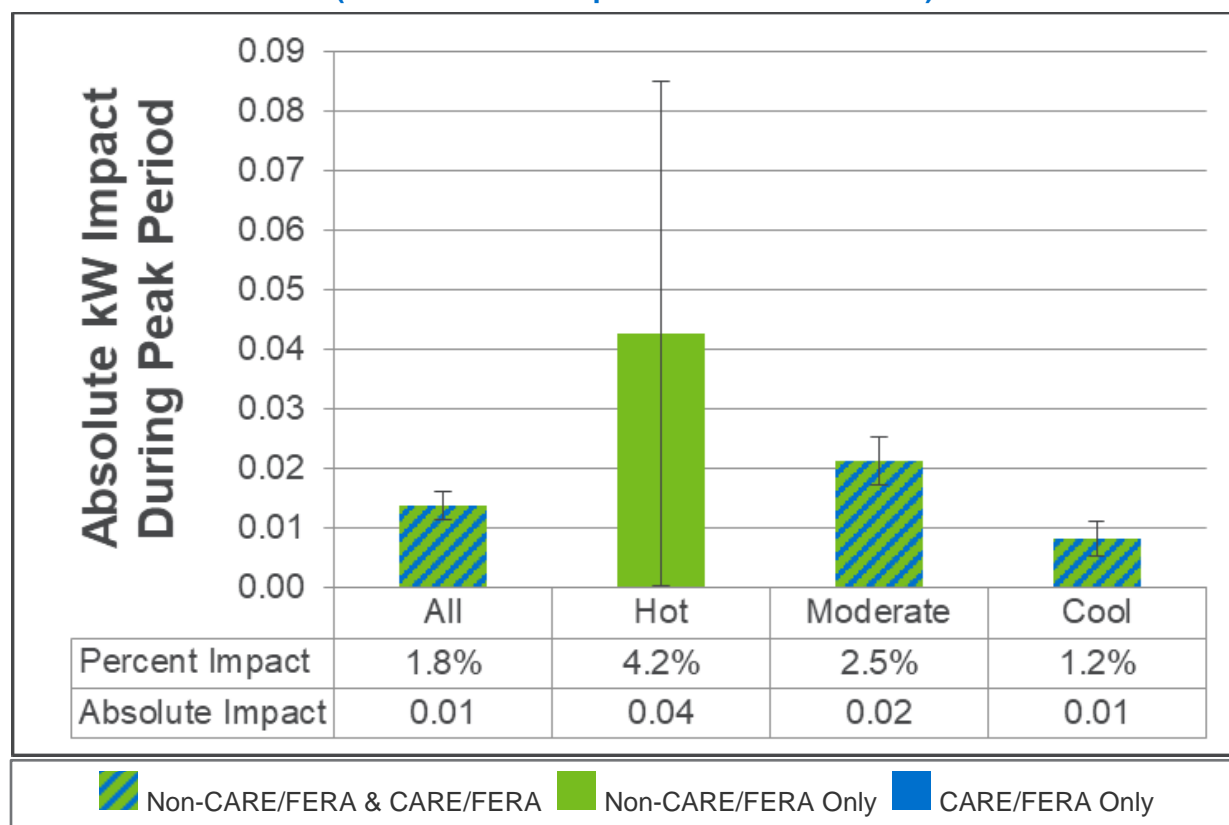


Table 5-4 presents estimates of load impacts for all relevant rate periods and day types for Rate 2 at the service territory and climate region level. Average reference load usage was 0.77 at the overall level during the peak period on the average weekday. The highest demand estimates were observed in the hot climate region on monthly system peak days during the peak period with a reference load of 1.27 kW.

For the average weekday, average weekend, and monthly system peak days, there were statistically significant load reductions during the peak period in every climate region and at the service territory level, except for the hot region on the average weekend. There were off-peak load increases in the overall group for the average weekday, average weekend, and monthly system peak days. However, any changes in the net load for the entire weekday were not statistically significant.

The largest load reduction of 13%, or 0.17 kW, occurred in the hot climate region during the peak period on the average monthly system peak day. However, the sample size of customers

enrolled on Rate 2 in SDG&E's hot climate region is very small (115 treatment customers) so the confidence bands on this estimate are wide and this load impact estimate is highly uncertain.

Table 5-4: Average Hourly Load Impacts by Climate Region, Rate Period and Day Type for SDG&E Rate 2
(Positive values represent load reductions, negative values represent load increases)

Rate 2														
Day Type	Period	Hours	All			Hot			Moderate			Cool		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	0.77	0.01	1.8%	1.02	0.04	4.2%	0.85	0.02	2.5%	0.71	0.01	1.2%
	Off-Peak	9 PM to 4 PM	0.54	>-0.01	-0.3%	0.66	-0.03	-3.9%	0.58	>-0.01	-0.1%	0.52	>-0.01	-0.5%
	Day	All Hours	0.59	<0.01	0.2%	0.74	-0.01	-1.6%	0.63	<0.01	0.6%	0.56	>-0.01	0.0%
Average Weekend	Peak	4 PM to 9 PM	0.79	0.01	1.8%	1.10	0.02	2.2%	0.87	0.02	2.2%	0.72	0.01	1.4%
	Off-Peak	9 PM to 4 PM	0.57	>-0.01	-0.3%	0.73	-0.02	-2.7%	0.61	<0.01	0.1%	0.54	>-0.01	-0.6%
	Day	All Hours	0.61	<0.01	0.3%	0.81	-0.01	-1.3%	0.66	<0.01	0.7%	0.58	>-0.01	-0.1%
Monthly System Peak Day	Peak	4 PM to 9 PM	1.03	0.02	2.0%	1.27	0.17	13.0%	1.19	0.03	2.4%	0.92	0.01	1.3%
	Off-Peak	9 PM to 4 PM	0.66	-0.01	-0.9%	0.79	0.02	2.9%	0.73	-0.01	-0.9%	0.61	-0.01	-1.0%
	Day	All Hours	0.74	>-0.01	0.0%	0.89	0.05	5.9%	0.82	<0.01	0.1%	0.67	>-0.01	-0.3%

* A shaded cell indicates estimate is not statistically significant

Figure 5-7 shows the peak-period load reductions on weekdays for non-CARE/FERA and CARE/FERA customers. Non-CARE/FERA customers in the service territory as a whole had greater percent impacts (2.0% and 0.02 kW) than the combined moderate and cool climate region for CARE/FERA (1.1% and 0.01 kW) and these differences are statistically significant in both absolute and percentage terms. CARE/FERA customers also had statistically significantly smaller load impacts in the cool and moderate climate regions, compared to the non-CARE/FERA segments. However, the CARE/FERA impacts themselves were not statistically significant in the cool region.

Figure 5-7: Average Peak Period Impacts for SDG&E Rate 2 by Climate Region & CARE/FERA Status
(Positive values represent load reductions)

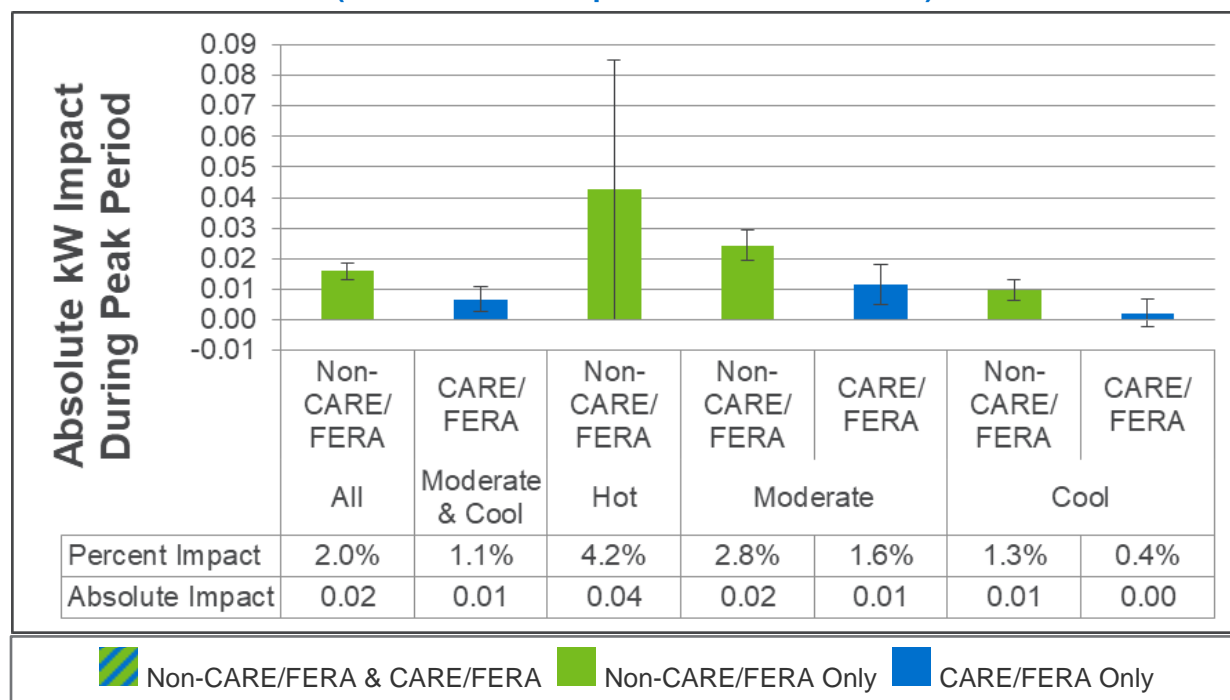


Table 5-5 and Table 5-6 show the load impacts for each rate period and day type for Rate 2 at the service territory level and across climate regions for non-CARE/FERA and CARE/FERA customers, respectively. Non-CARE/FERA customers had higher average load and load reductions during peak periods across all climate regions on average weekdays, weekends and monthly system peak days.

Non-CARE/FERA customers had statistically significant load increases during the off-peak periods for the service territory as a whole and for the hot and cool climate regions on average weekdays and weekends. This was true for CARE/FERA customers in all climate regions on average weekdays, weekends, and monthly system peak days. Neither CARE/FERA nor non-CARE/FERA customers exhibited any statistically significant changes to their overall average daily load for any of the day types.

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

Rate 2														
Day Type	Period	Hours	All - Non-CARE/FERA			Hot - Non-CARE/FERA			Moderate - Non-CARE/FERA			Cool - Non-CARE/FERA		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	0.80	0.02	2.0%	1.02	0.04	4.2%	0.89	0.02	2.8%	0.74	0.01	1.3%
	Off-Peak	9 PM to 4 PM	0.56	>-0.01	-0.3%	0.66	-0.03	-3.9%	0.60	<0.01	0.0%	0.54	>-0.01	-0.4%
	Day	All Hours	0.61	<0.01	0.3%	0.74	-0.01	-1.6%	0.66	0.01	0.8%	0.58	<0.01	0.0%
Average Weekend	Peak	4 PM to 9 PM	0.82	0.02	1.9%	1.10	0.02	2.2%	0.91	0.02	2.3%	0.76	0.01	1.5%
	Off-Peak	9 PM to 4 PM	0.59	>-0.01	-0.2%	0.73	-0.02	-2.7%	0.63	<0.01	0.2%	0.56	>-0.01	-0.5%
	Day	All Hours	0.64	<0.01	0.3%	0.81	-0.01	-1.3%	0.69	0.01	0.8%	0.60	<0.01	0.0%
Monthly System Peak Day	Peak	4 PM to 9 PM	1.08	0.03	2.4%	1.27	0.17	13.0%	1.25	0.04	2.9%	0.96	0.02	1.6%
	Off-Peak	9 PM to 4 PM	0.69	-0.01	-0.8%	0.79	0.02	2.9%	0.76	-0.01	-0.7%	0.64	-0.01	-1.1%
	Day	All Hours	0.77	<0.01	0.1%	0.89	0.05	5.9%	0.86	<0.01	0.4%	0.71	>-0.01	-0.3%

* A shaded cell indicates estimate is not statistically significant

Table 5-6: Average Hourly Load Impacts by Rate Period and Day Type for SDG&E Rate 2 by Climate Region –CARE/FERA
(Positive values represent load reductions, negative values represent load increases)

Rate 2														
Day Type	Period	Hours	Moderate & Cool - CARE/FERA			Hot - CARE/FERA			Moderate - CARE/FERA			Cool - CARE/FERA		
			Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact	Ref. kW	Impact kW	% Impact
Average Weekday	Peak	4 PM to 9 PM	0.63	0.01	1.1%	N/A	N/A	N/A	0.73	0.01	1.6%	0.53	<0.01	0.4%
	Off-Peak	9 PM to 4 PM	0.44	>-0.01	-0.7%	N/A	N/A	N/A	0.49	>-0.01	-0.6%	0.38	>-0.01	-0.7%
	Day	All Hours	0.47	>-0.01	-0.2%	N/A	N/A	N/A	0.54	>-0.01	0.0%	0.41	>-0.01	-0.4%
Average Weekend	Peak	4 PM to 9 PM	0.62	0.01	1.3%	N/A	N/A	N/A	0.72	0.01	2.0%	0.53	<0.01	0.4%
	Off-Peak	9 PM to 4 PM	0.45	>-0.01	-0.6%	N/A	N/A	N/A	0.52	>-0.01	-0.3%	0.40	>-0.01	-1.0%
	Day	All Hours	0.49	>-0.01	-0.1%	N/A	N/A	N/A	0.56	<0.01	0.3%	0.42	>-0.01	-0.6%
Monthly System Peak Day	Peak	4 PM to 9 PM	0.80	<0.01	0.5%	N/A	N/A	N/A	0.96	0.01	1.0%	0.64	>-0.01	-0.1%
	Off-Peak	9 PM to 4 PM	0.52	>-0.01	-0.6%	N/A	N/A	N/A	0.61	-0.01	-1.3%	0.44	<0.01	0.4%
	Day	All Hours	0.58	>-0.01	-0.3%	N/A	N/A	N/A	0.68	>-0.01	-0.7%	0.48	<0.01	0.2%

* A shaded cell indicates estimate is not statistically significant

5.4 Comparison across Rates

Figure 5-8 shows the average weekday peak-period impact for Rate 1 and Rate 2 in the summer months. The peak period covers the same hours for each rate (4 PM to 9 PM) and the peak-period price is slightly higher for Rate 1 (56 ¢/kWh) compared with Rate 2 (53 ¢/kWh). The difference in load impacts at the service territory level is statistically significant but is driven by the statistically significant difference in the moderate climate region. There are no statistically significant differences between Rate 1 and Rate 2 in the hot or cool climate regions. Recall that

there were different estimation methods used for each rate due to the complications with the treatment and control population assignments. Furthermore, Net Energy Metering (NEM) customers were allowed to enroll on Rate 1 but excluded from Rate 2. Accordingly, these differences should be taken into consideration when comparing the results.

Figure 5-8: Average Peak Period Impacts from 4 PM to 9 PM across Rates
(Positive values represent load reductions)

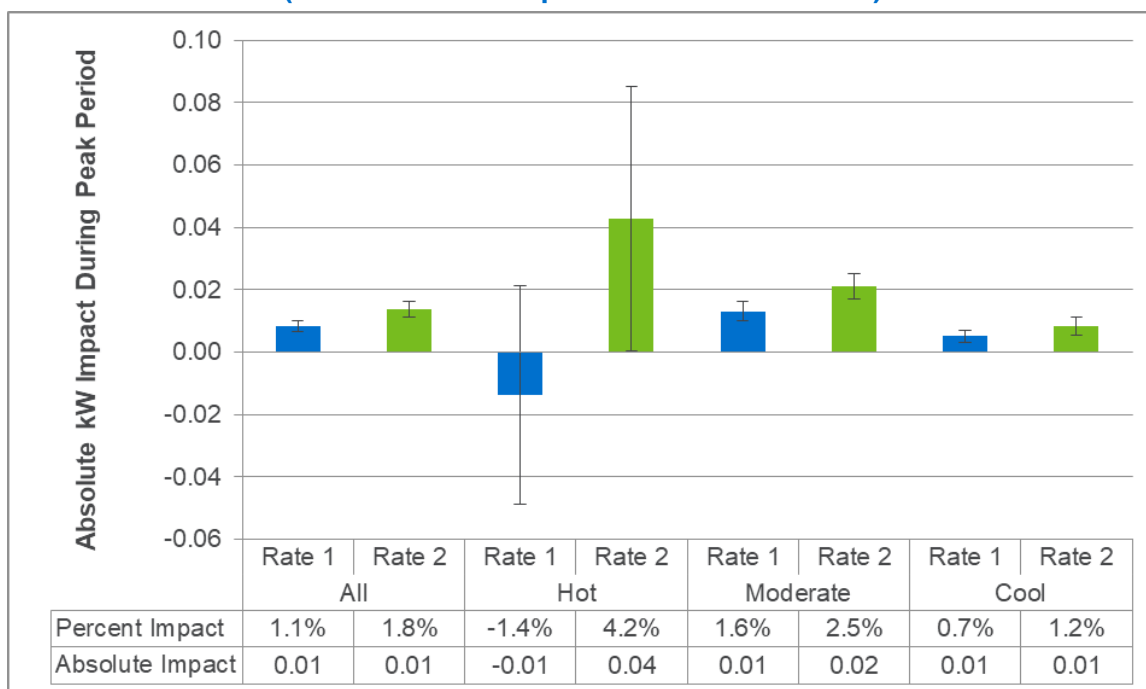
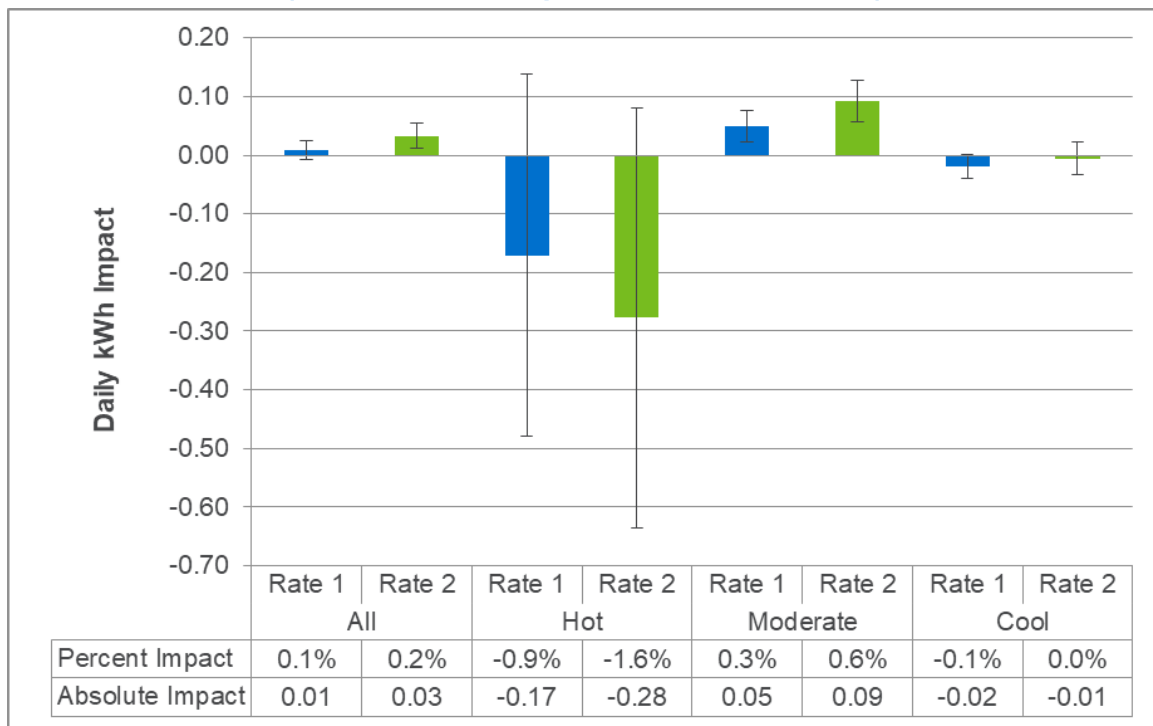


Figure 5-9 shows the average daily kWh impact during the summer period for Rate 1 and Rate 2. At the territory level, customers on Rate 2 showed statistically significant average daily kWh usage reductions, while customers on Rate 1 did not show any statistically significant change. Customers on both rates in the moderate climate region showed statistically significant daily reductions in consumption. Customers on both rates in the hot and cool climate regions showed daily increases in consumption, but they were not statistically significant.

Figure 5-9: Average Daily kWh Impacts across Rates
(Positive values represent load reductions)



6 Persistence of Load Impacts

The impacts in this section represent the population of customers who remained active SDG&E D-TOU customers from April 2018 until the end of October 2019. Using this method, it is possible to compare impacts between the two pilot summer seasons for a single consistent group of customers, rather than a changing population. A comparison of load impacts for customers enrolled in 2018 with those enrolled in 2019 is not a valid estimate of persistence since any observed difference might be due in large part to changes in the participant population rather than changes in behavior of customers that participated in both summer periods. Customers who opted out of the pilot are included here to maintain the RED, and the methodology used here is identical to that used in the ex post impact analysis. While there is not a second winter for persistence comparison, the winter impacts for the persistent subset of customers are included with the two summer impacts to illustrate the relative differences in impacts between the summer and winter seasons for a common set of customers.

6.1 Rate 1

Figure 6-1 presents the average percent impacts for the peak period for non-NEM customers who remained active SDG&E TOU customers through the second summer of the pilot (October 2019). This represented approximately 66,000 Rate 1 customers between 2018 and 2019. All three seasons are presented for the territory as a whole and for each climate region. In the overall service territory, there was a decrease in impacts between summer 2018 and summer 2019. Impacts for the first and second summer were about 1.6% in 2018 and 1.1% in 2019. While the percent impacts were similar, the difference was statistically significant in both absolute and percentage terms. For the territory as a whole, load impacts were smaller in winter than in the summer seasons. This was also true for customers in the moderate climate region. In the hot and cool climate regions, the winter impacts were smaller than those in the first summer, but larger than those in the second summer. However, there are again large error bands in the hot climate region due to its relatively small population size.

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

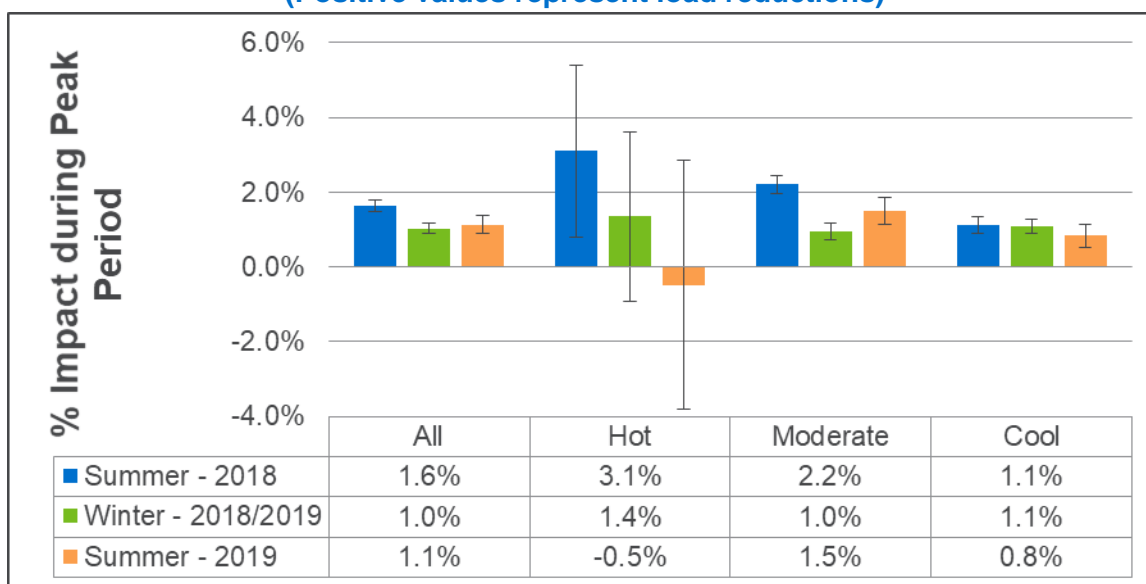


Figure 6-2 presents the impacts for the persistent set of NEM customers relative to the non-NEM population. These customers showed a statistically significant decrease in impacts after the first summer in both the winter and second summer. The percentage impacts decreased from 5% to -0.9% in the winter and -0.5% in the second summer. Although the error bands are wide for NEM due to the smaller population size, the decreases are still statistically significant.

Figure 6-2: Percent Impacts for Peak Period for Rate 1 – Non-NEM and NEM, by Season
(Positive values represent load reductions)

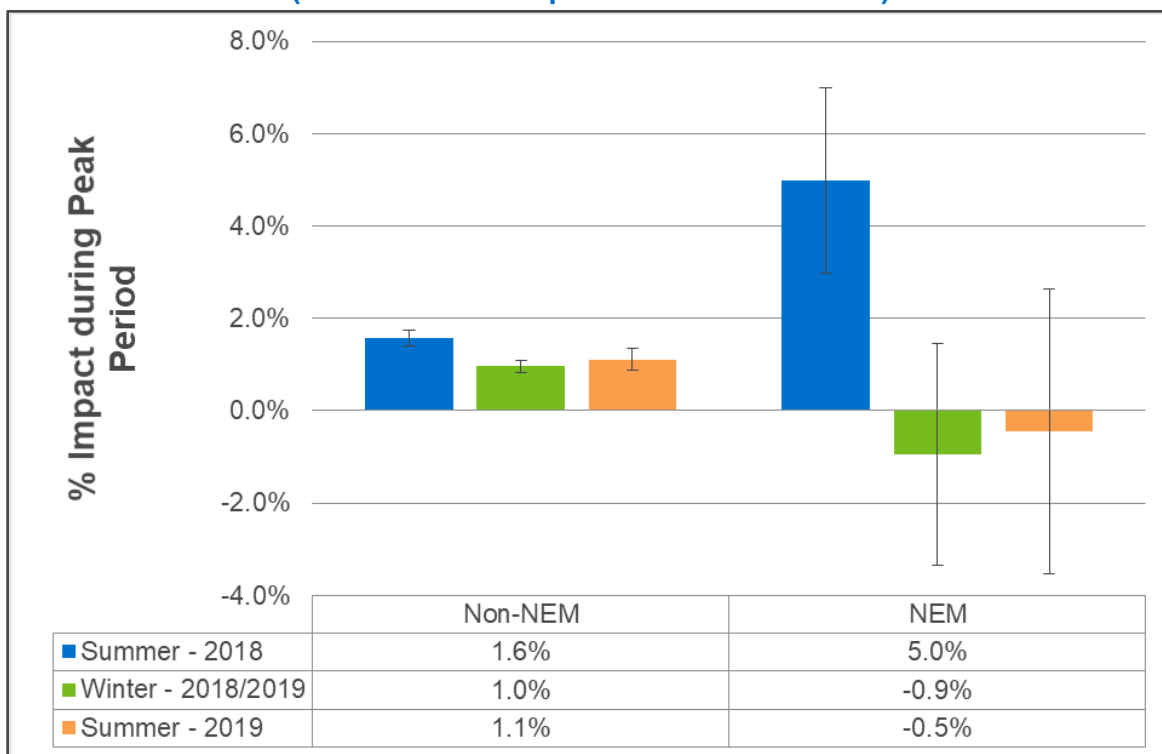
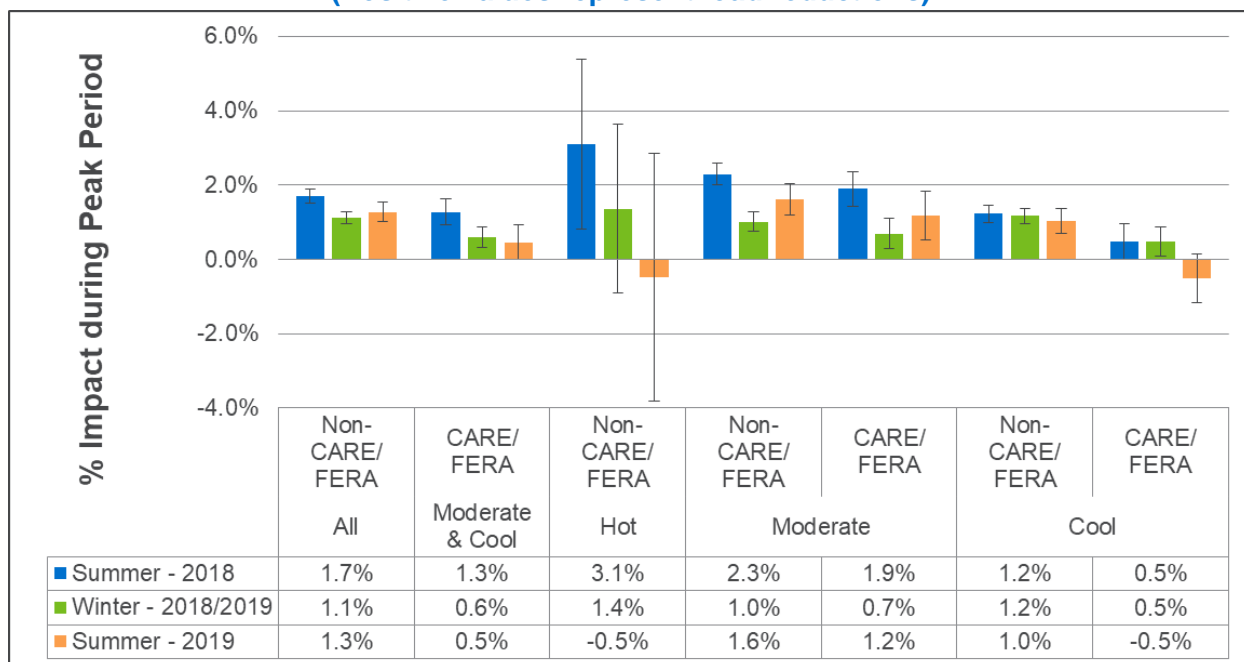


Figure 6-3 presents average seasonal impacts for non-CARE/FERA and CARE/FERA customers on Rate 1. CARE/FERA customers in the combined climate region showed a statistically significant decrease in percent impacts between the first and second summer, but these decreases were not statistically significant in the individual climate regions. Non-CARE/FERA showed statistically significant decreases in the overall and moderate climate regions. The non-CARE/FERA customers in the hot climate region and the CARE/FERA customers in the cool climate region showed negative percent impacts in the second summer, but they were not statistically significant.

Figure 6-3: Percent Impacts for Peak Period for Rate 1 – Non-NEM, by Season For CARE/FERA and Non-CARE/FERA Customers
(Positive values represent load reductions)



6.2 Rate 2

Figure 6-4 presents seasonal load impacts for Rate 2 customers in SDG&E's territory as a whole and for each climate region. Recall that in this evaluation, Rate 2's population does not include any NEM customers and that these persistent load impacts only represent customers who remained active SDG&E participants through the end of the second summer of the pilot. This represented approximately 16,000 Rate 2 customers between 2018 and 2019. For each climate zone and the SDG&E territory as a whole, impacts were greatest during the first summer (June through October 2018). The differences between the two summers were statistically significant in the overall territory and in the cool climate region. The winter load impacts were statistically significantly smaller than those in both summers in both the overall territory and the moderate climate region.

Figure 6-4: Percent Impacts for Peak Period for Rate 2, by Season
(Positive values represent load reductions)

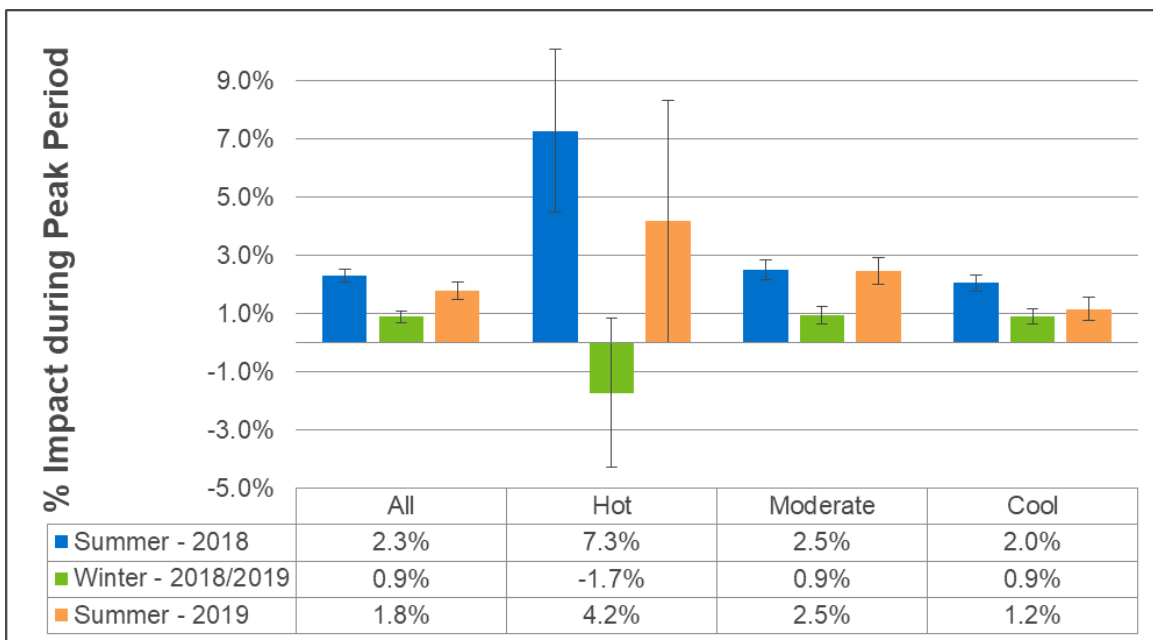
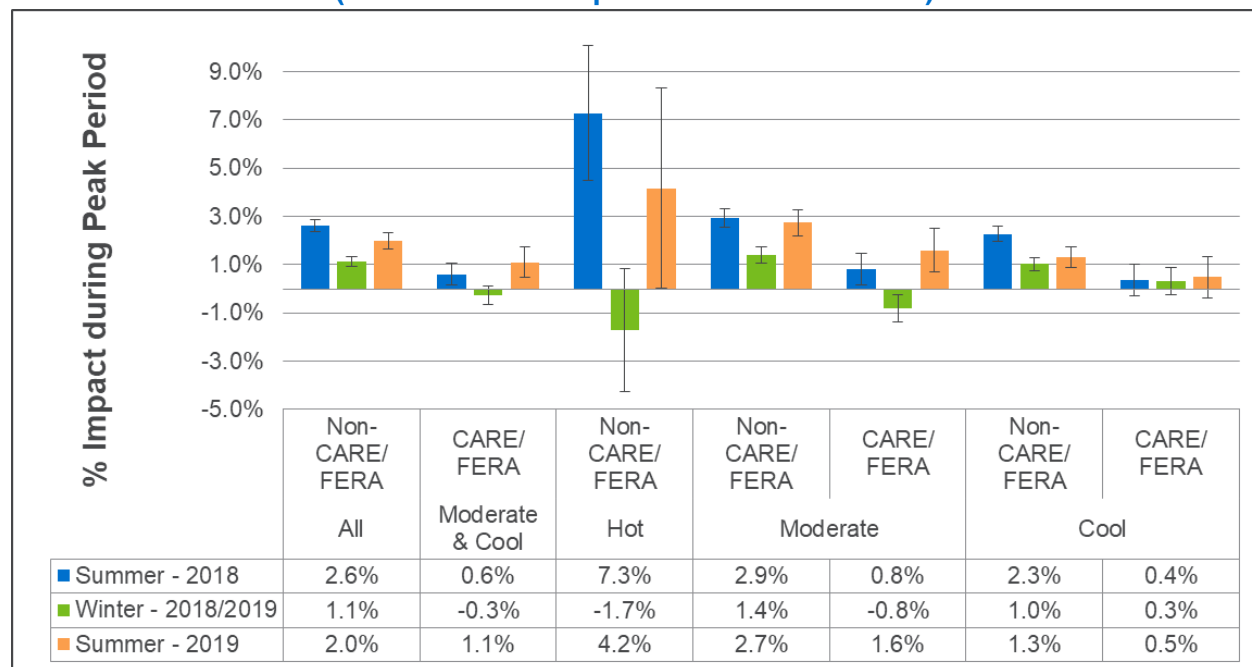


Figure 6-5 presents average seasonal impacts for non-CARE/FERA and CARE/FERA customers on Rate 2. CARE/FERA customers did not show statistically significant differences in impacts between the first and second summers. However, for CARE/FERA customers in the moderate climate zone, the decrease from 0.8% in the first summer to -0.8% in the winter, and the subsequent increase to 1.6% in the second summer were both statistically significant changes. Non-CARE/FERA customers in the overall territory showed a similar pattern of decreasing impacts between the first summer and the winter and decreasing impacts between the first summer and the second summer. In all cases, the winter percent impacts were lower than the summer impacts.

**Figure 6-5: Percent Impacts for Peak Period for Rate 2, by Season
For CARE/FERA and Non-CARE/FERA Customers
(Positive values represent load reductions)**



6.3 Comparison of 2018 and 2019 Weather

Several factors contribute to differences in load impacts from year to year, and a key driver is weather. Figure 6-6 presents non-NEM Rate 1 average weekday peak period impacts and temperatures for the summer periods in 2018 and 2019. Figure 6-7 presents the same information for Rate 2. Although it is difficult to compare the average peak load impacts between 2018 and 2019, a collection of average summer weekday impacts for the two years can be examined graphically to visualize how customers performed from year to year. The following figures illustrate that on average, temperatures were cooler in 2019 (average *mean* of 69 °F versus 71 °F in 2018). It also shows that at similar temperatures, impacts in 2019 were slightly lower than impacts in 2018 (the green trendline is below the blue trendline). It may be possible that customers were slightly less responsive to the rates in the second summer.

Figure 6-6: Comparison of Summer Average Weekday Peak Period Temperatures and Impacts – Rate 1

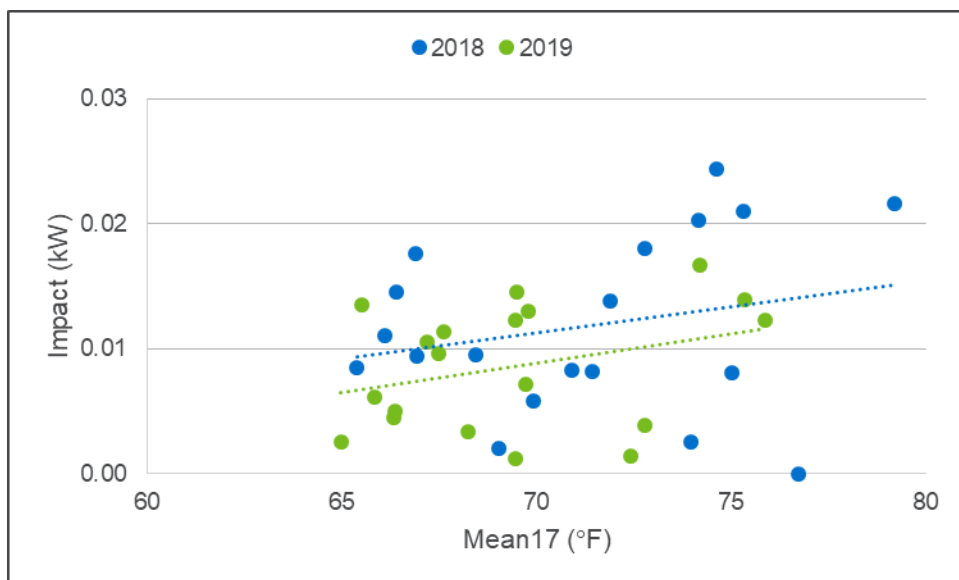
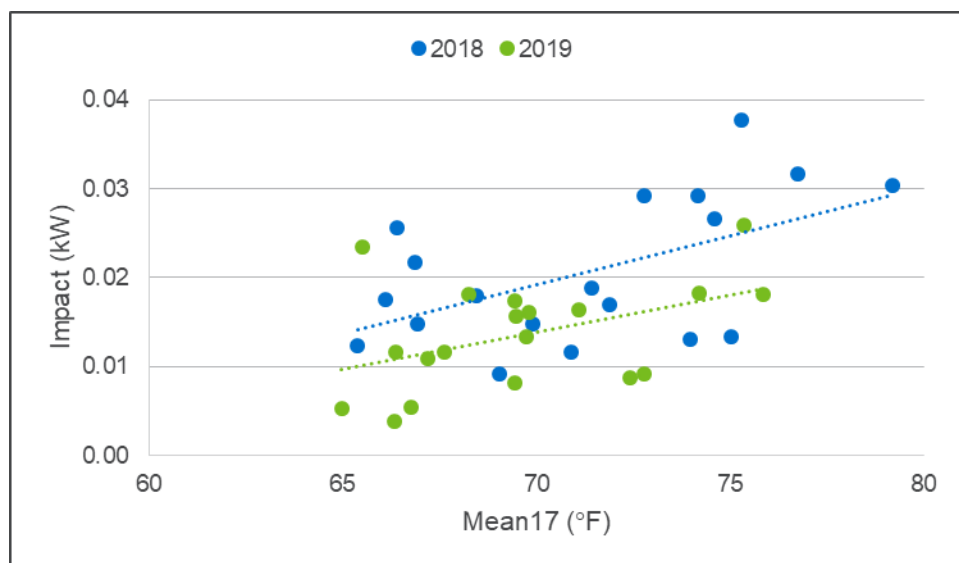


Figure 6-7: Comparison of Summer Average Weekday Peak Period Temperatures and Impacts – Rate 2



7 Ex Ante Load Impacts

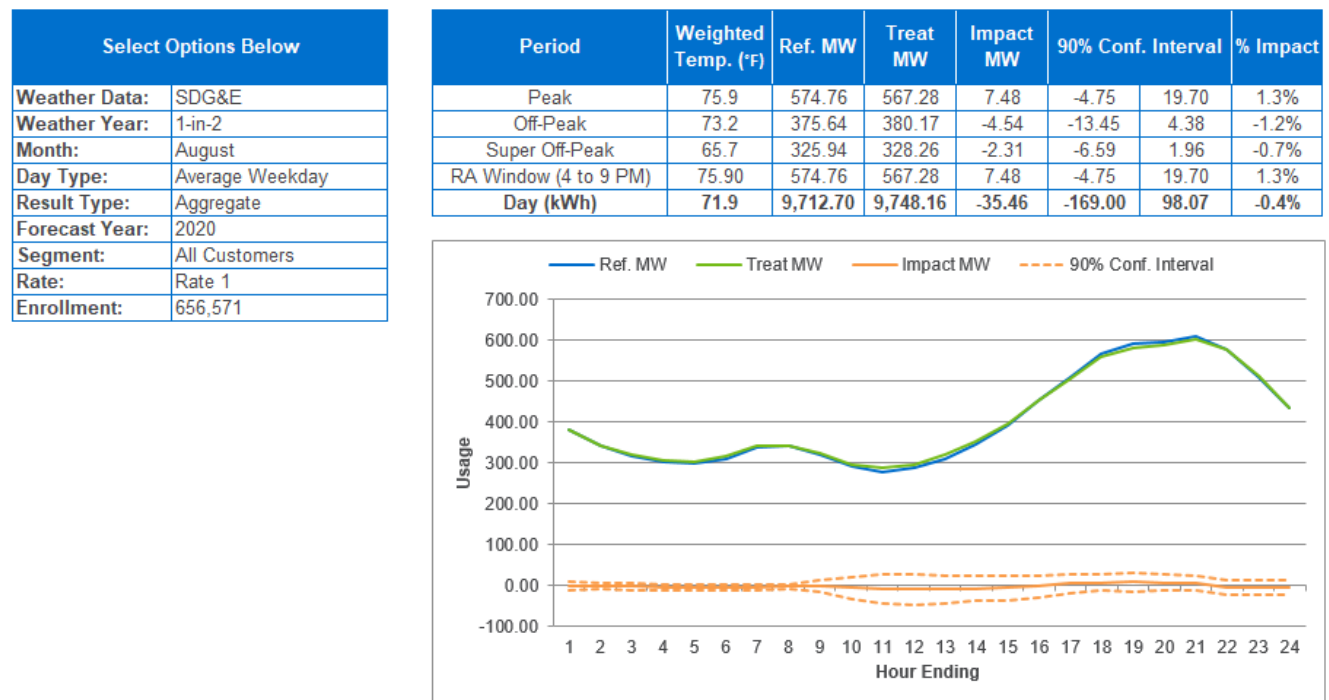
Ex ante load impacts represent what customers on the default TOU rates can deliver under a standardized set of weather conditions given changes in enrollment over the forecast horizon. The weather used for ex ante load impact estimation is meant to reflect conditions on the average weekday under both 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 1 and Rate 2 peak period (4 to 9 PM). The current RA window is in effect during all months of the year.

At a high level, ex ante impact estimates for Rate 1 and Rate 2 were developed using the following process:

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

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

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



Hour Ending	Period	Ref. MW	Treat MW	Impact MW	% Impact	Weighted Temp. (°F)	Uncertainty-adjusted Impact - Percentiles				
							10th	30th	50th	70th	90th
1	Super Off-Peak	380.66	381.40	-0.74	-0.2%	66.9	-11.93	-5.32	-0.74	3.84	10.46
2	Super Off-Peak	343.26	343.61	-0.34	-0.1%	66.4	-8.98	-3.88	-0.34	3.19	8.29
3	Super Off-Peak	318.54	320.19	-1.65	-0.5%	65.9	-10.15	-5.13	-1.65	1.83	6.86
4	Super Off-Peak	302.76	305.91	-3.15	-1.0%	65.5	-10.20	-6.03	-3.15	-0.26	3.90
5	Super Off-Peak	298.54	302.67	-4.13	-1.4%	65.0	-10.47	-6.72	-4.13	-1.54	2.21
6	Super Off-Peak	311.89	315.76	-3.87	-1.2%	64.7	-10.02	-6.39	-3.87	-1.36	2.27
7	Off-Peak	338.78	341.10	-2.33	-0.7%	64.6	-9.52	-5.27	-2.33	0.62	4.86
8	Off-Peak	341.15	342.57	-1.42	-0.4%	65.5	-6.76	-3.61	-1.42	0.77	3.93
9	Off-Peak	322.17	323.31	-1.14	-0.4%	68.5	-15.57	-7.04	-1.14	4.77	13.29
10	Off-Peak	292.03	297.28	-5.25	-1.8%	71.9	-31.58	-16.02	-5.25	5.52	21.07
11	Off-Peak	279.42	287.95	-8.53	-3.1%	75.9	-44.23	-23.14	-8.53	6.08	27.16
12	Off-Peak	287.02	295.92	-8.91	-3.1%	78.4	-44.91	-23.64	-8.91	5.83	27.10
13	Off-Peak	311.53	320.11	-8.58	-2.8%	79.7	-42.56	-22.49	-8.58	5.32	25.39
14	Off-Peak	346.53	353.61	-7.09	-2.0%	80.2	-37.34	-19.46	-7.09	5.29	23.17
15	Off-Peak	391.38	396.45	-5.07	-1.3%	80.4	-34.55	-17.13	-5.07	6.99	24.40
16	Off-Peak	452.46	454.19	-1.72	-0.4%	80.3	-27.93	-12.45	-1.72	9.00	24.49
17	Peak	510.30	504.71	5.59	1.1%	79.6	-18.70	-4.35	5.59	15.54	29.89
18	Peak	567.67	559.87	7.80	1.4%	78.4	-12.30	-0.42	7.80	16.03	27.91
19	Peak	591.57	582.63	8.94	1.5%	76.4	-14.46	-0.63	8.94	18.51	32.34
20	Peak	595.50	587.72	7.79	1.3%	73.8	-11.49	-0.10	7.79	15.67	27.06
21	Peak	608.75	601.49	7.25	1.2%	71.4	-11.58	-0.45	7.25	14.96	26.09
22	Off-Peak	576.75	579.58	-2.83	-0.5%	69.9	-20.75	-10.16	-2.83	4.50	15.09
23	Off-Peak	510.15	513.47	-3.32	-0.7%	68.9	-22.25	-11.07	-3.32	4.43	15.61
24	Off-Peak	433.89	436.66	-2.77	-0.6%	68.3	-20.05	-9.84	-2.77	4.30	14.51

7.1 Enrollment Forecast

Territory-wide mass defaulting of residential customers throughout 2019 led to a large growth in the starting point for the enrollment forecast for the ex ante analysis, beginning at about 700,000 for Rate 1 and 28,500 for Rate 2 in March 2020. Table 7-1 summarizes the enrollment forecast for Rate 1 and Rate 2 for January of each forecast year from 2020 through 2030. Enrollment onto Rate 1 is expected to grow at a rate of 1% per year. After 2021, no new enrollments are anticipated for Rate 2, and the population is expected to decline by approximately 1% per year (based on account closure and opt out rates observed in 2018 and 2019). For the NEM and Non-NEM forecasts, the proportion of all NEM customers, including those who enrolled during the treatment period, were carried forward through the forecast horizon. At the end of summer 2019, this proportion was approximately 5.6%.

Table 7-1: Enrollment Forecast by Rate and Forecast Year, All Customers (Non-NEM and NEM)

Forecast Year	Rate 1	Rate 2
2020	699,102	28,552
2021	710,135	28,906
2022	721,340	29,236
2023	728,587	28,945
2024	735,906	28,656
2025	743,299	28,371
2026	750,766	28,089
2027	758,308	27,809
2028	765,926	27,532
2029	773,621	27,258
2030	781,393	26,987

7.2 Rate 1

Table 7-2 presents per customer ex ante load reduction estimates for the average weekday under CAISO and SDG&E conditions. This table and the following tables represent impact estimates expected during the Resource Adequacy (RA) window, from 4 to 9 PM, which is the same as the peak period for Rate 1. Under 1-in-2 and 1-in-10 conditions, impacts are expected to be 0.00 kW in the shoulder months and 0.01 kW in the summer months.

Table 7-2: Average Weekday Ex Ante Impact Estimates Per Customer – All Rate 1 Customers (Non-NEM and NEM)

Weather Year	Month	SDG&E		CAISO	
		Impact (kW)	mean17 (°F)	Impact (kW)	mean17 (°F)
1-in-2	January	0.01	57.7	0.01	57.7
	February	0.00	54.8	0.00	54.8
	March	0.00	59.3	0.00	57.8
	April	0.00	60.5	0.00	58.5
	May	0.00	62.6	0.00	63.0
	June	0.00	64.9	0.00	64.5
	July	0.01	69.3	0.01	70.5
	August	0.01	71.7	0.01	72.9
	September	0.01	70.3	0.01	70.3
	October	0.00	65.2	0.00	64.1
	November	0.00	57.8	0.00	61.5
	December	0.01	54.9	0.01	57.3
1-in-10	January	0.00	52.9	0.00	52.8
	February	0.00	53.5	0.00	53.6
	March	0.00	57.8	0.00	57.8
	April	0.00	63.0	0.00	62.4
	May	0.00	65.0	0.00	63.4
	June	0.01	68.3	0.01	68.3
	July	0.01	72.2	0.01	72.1
	August	0.01	73.9	0.01	73.9
	September	0.01	74.7	0.01	74.7
	October	0.01	69.2	0.01	69.2
	November	0.00	63.2	0.00	63.2
	December	0.00	53.1	0.01	54.3

Figure 7-2 presents the average weekday impacts during the RA window under 1-in-2 and 1-in-10 SDG&E weather conditions with more detail. The greatest impacts for 1-in-2 and 1-in-10 SDG&E weather conditions occur in August, and September and are expected to be approximately 0.01 kW per customer. Impacts are smallest in February and March.

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 Weekday Ex Ante Impact Estimates – SDG&E Weather, All Rate 1 Customers (Non-NEM and NEM)

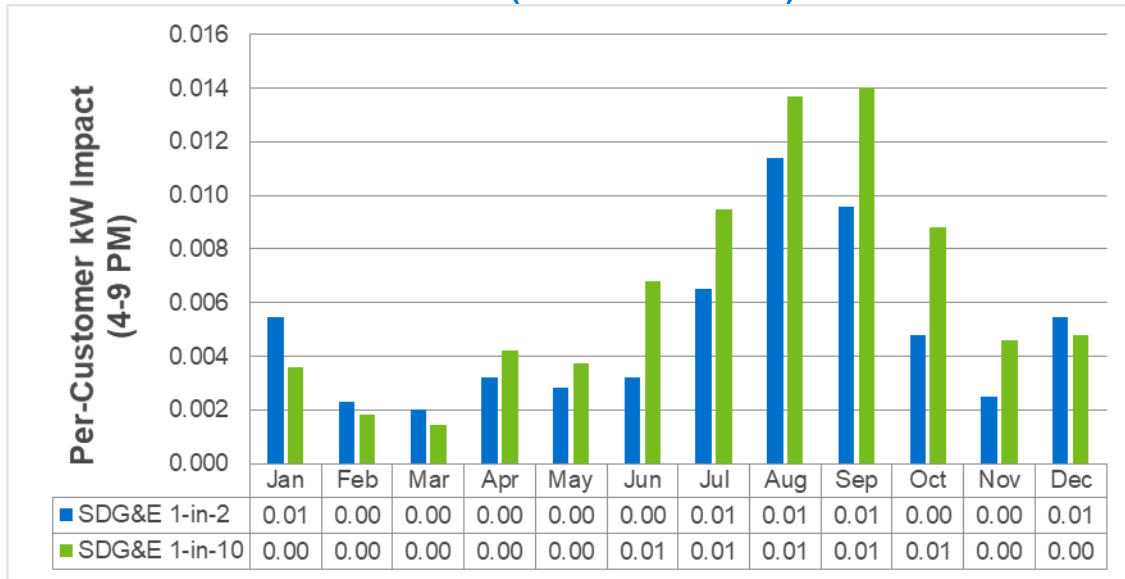


Table 7-3 summarizes the aggregate ex ante load impact estimates for each month and year of the forecast. The impacts presented in this table are in MW. As described previously, impacts are expected to be greatest in the summer months. The largest expected load impact of 11.0 MW occurs in September under 1-in-10 conditions, when the ex ante weather is warmest and when enrollment is expected to be near its highest. Aggregate impacts are expected to be smallest in March, with a forecast of 1.1 MW in most years.

Table 7-3: Aggregate MW Ex Ante Load Impacts by Forecast Year and Month, All Rate 1 Customers (Non-NEM and NEM)

Weather Year	Forecast Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SDG&E 1-in-2	2020	3.8	1.6	1.4	2.3	2.0	2.3	4.6	8.0	6.8	3.4	1.8	3.9
	2021	3.9	1.7	1.4	2.3	2.0	2.3	4.7	8.2	6.9	3.5	1.8	3.9
	2022	3.9	1.7	1.5	2.3	2.0	2.3	4.7	8.3	7.0	3.5	1.8	4.0
	2023	4.0	1.7	1.5	2.4	2.1	2.4	4.8	8.3	7.0	3.5	1.8	4.0
	2024	4.0	1.7	1.5	2.4	2.1	2.4	4.8	8.4	7.1	3.6	1.9	4.1
	2025	4.0	1.7	1.5	2.4	2.1	2.4	4.9	8.5	7.2	3.6	1.9	4.1
	2026	4.1	1.7	1.5	2.4	2.1	2.4	4.9	8.6	7.2	3.6	1.9	4.1
	2027	4.1	1.8	1.5	2.4	2.2	2.5	5.0	8.7	7.3	3.7	1.9	4.2
	2028	4.2	1.8	1.6	2.5	2.2	2.5	5.0	8.8	7.4	3.7	1.9	4.2
	2029	4.2	1.8	1.6	2.5	2.2	2.5	5.1	8.9	7.5	3.7	1.9	4.3
	2030	4.3	1.8	1.6	2.5	2.2	2.5	5.1	8.9	7.5	3.8	2.0	4.3
SDG&E 1-in-10	2020	2.5	1.3	1.0	3.0	2.6	4.8	6.7	9.7	9.9	6.2	3.2	3.4
	2021	2.5	1.3	1.0	3.0	2.7	4.9	6.8	9.8	10.1	6.3	3.3	3.4
	2022	2.6	1.3	1.0	3.0	2.7	4.9	6.9	9.9	10.2	6.4	3.3	3.5
	2023	2.6	1.3	1.1	3.1	2.7	5.0	6.9	10.0	10.3	6.5	3.4	3.5
	2024	2.6	1.4	1.1	3.1	2.8	5.0	7.0	10.1	10.4	6.5	3.4	3.5
	2025	2.7	1.4	1.1	3.1	2.8	5.1	7.1	10.2	10.5	6.6	3.4	3.6
	2026	2.7	1.4	1.1	3.2	2.8	5.1	7.2	10.3	10.6	6.7	3.5	3.6
	2027	2.7	1.4	1.1	3.2	2.9	5.2	7.2	10.4	10.7	6.7	3.5	3.7
	2028	2.8	1.4	1.1	3.2	2.9	5.2	7.3	10.6	10.8	6.8	3.5	3.7
	2029	2.8	1.4	1.1	3.3	2.9	5.3	7.4	10.7	10.9	6.9	3.6	3.7
	2030	2.8	1.4	1.1	3.3	2.9	5.3	7.5	10.8	11.0	6.9	3.6	3.8

7.3 Rate 2

Table 7-4 summarizes the average weekday ex ante impact estimates for Rate 2 under 1-in-2 and 1-in-10 SDG&E and CAISO weather conditions for the RA window from 4 to 9 PM, which is also the peak period for Rate 2. Impacts for Rate 2 are expected to be greater than those for Rate 1, especially in the warmer summer months. Under 1-in-2 SDG&E weather conditions, impacts are expected to reach 0.02 kW per customer in July. Under 1-in-10 SDG&E and CAISO conditions, impacts are forecasted to reach 0.02 kW in June, July, August, and September.

Table 7-4: Average Weekday Ex Ante Impact Estimates Per Customer – All Rate 2 Customers (Non-NEM and NEM)

Weather Year	Month	SDG&E		CAISO	
		Impact (kW)	mean17 (°F)	Impact (kW)	mean17 (°F)
1-in-2	January	0.01	57.7	0.01	57.7
	February	0.01	54.8	0.01	54.8
	March	0.00	59.3	0.00	57.8
	April	0.01	60.5	0.01	58.5
	May	0.01	62.6	0.01	63.0
	June	0.01	64.9	0.01	64.5
	July	0.02	69.3	0.02	70.4
	August	0.01	71.7	0.02	72.9
	September	0.01	70.3	0.01	70.3
	October	0.00	65.2	0.00	64.2
	November	0.01	57.8	0.01	61.5
	December	0.01	54.9	0.01	57.3
1-in-10	January	0.00	52.9	0.00	52.9
	February	0.01	53.6	0.01	53.6
	March	0.00	57.8	0.00	57.8
	April	0.01	63.1	0.01	62.4
	May	0.01	65.0	0.01	63.4
	June	0.02	68.2	0.02	68.2
	July	0.02	72.2	0.02	72.1
	August	0.02	73.9	0.02	73.9
	September	0.02	74.7	0.02	74.7
	October	0.01	69.2	0.01	69.2
	November	0.01	63.2	0.01	63.2
	December	0.01	53.1	0.01	54.3

Figure 7-3 presents the average weekday impacts during the RA window under 1-in-2 and 1-in-10 SCE weather conditions for Rate 2. Similar to Rate 1, 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 7-3: Average Weekday Ex Ante Impact Estimates – SDG&E Weather, All Rate 2 Customers (Non-NEM and NEM)

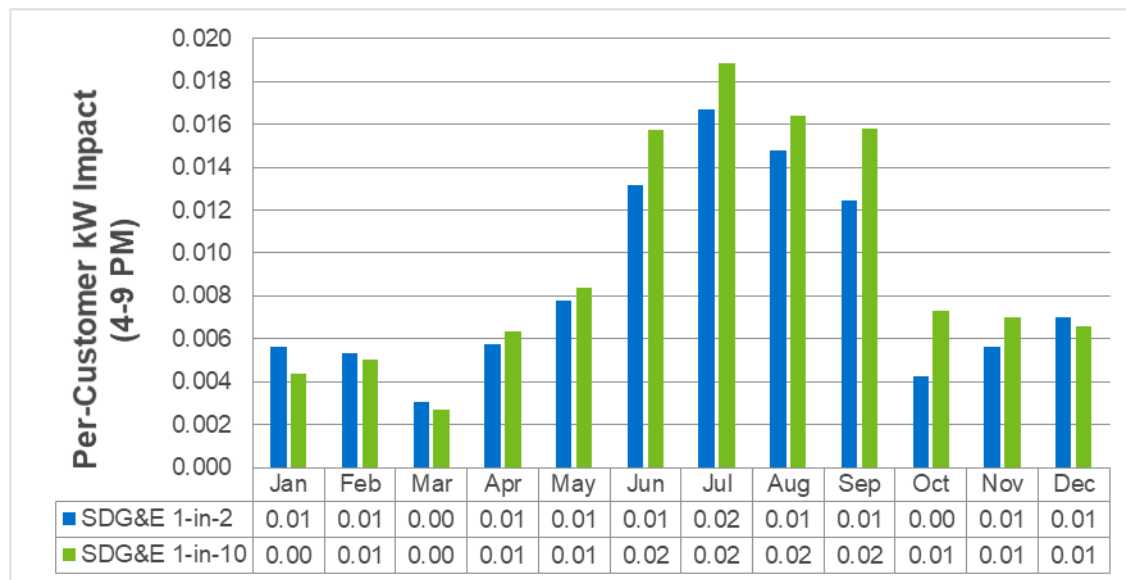


Table 7-5 summarizes the aggregate ex ante load impact estimates for each month and year of the forecast for Rate 2. Again, the impacts presented in this table are in MW, not kW. Like Rate 1, impacts are expected to be greatest in the summer months. The largest impacts are expected in July of both weather years in July (0.5 MW). The change in population from year to year is rather small, and as a result the aggregate impact is not expected to change drastically between 2020 and 2030.

Table 7-5: Aggregate MW Ex Ante Load Impacts by Forecast Year and Month, All Rate 2 Customers (Non-NEM and NEM)

Weather Year	Forecast Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
SDG&E 1-in-2	2020	0.2	0.2	0.1	0.2	0.2	0.4	0.5	0.4	0.4	0.1	0.2	0.2
	2021	0.2	0.2	0.1	0.2	0.2	0.4	0.5	0.4	0.4	0.1	0.2	0.2
	2022	0.2	0.2	0.1	0.2	0.2	0.4	0.5	0.4	0.4	0.1	0.2	0.2
	2023	0.2	0.2	0.1	0.2	0.2	0.4	0.5	0.4	0.4	0.1	0.2	0.2
	2024	0.2	0.2	0.1	0.2	0.2	0.4	0.5	0.4	0.4	0.1	0.2	0.2
	2025	0.2	0.2	0.1	0.2	0.2	0.4	0.5	0.4	0.4	0.1	0.2	0.2
	2026	0.2	0.2	0.1	0.2	0.2	0.4	0.5	0.4	0.3	0.1	0.2	0.2
	2027	0.2	0.1	0.1	0.2	0.2	0.4	0.5	0.4	0.3	0.1	0.2	0.2
	2028	0.2	0.1	0.1	0.2	0.2	0.4	0.5	0.4	0.3	0.1	0.2	0.2
	2029	0.2	0.1	0.1	0.2	0.2	0.4	0.5	0.4	0.3	0.1	0.2	0.2
	2030	0.2	0.1	0.1	0.2	0.2	0.4	0.4	0.4	0.3	0.1	0.2	0.2
SDG&E 1-in-10	2020	0.1	0.1	0.1	0.2	0.2	0.4	0.5	0.5	0.5	0.2	0.2	0.2
	2021	0.1	0.1	0.1	0.2	0.2	0.5	0.5	0.5	0.5	0.2	0.2	0.2
	2022	0.1	0.1	0.1	0.2	0.2	0.5	0.5	0.5	0.5	0.2	0.2	0.2
	2023	0.1	0.1	0.1	0.2	0.2	0.5	0.5	0.5	0.5	0.2	0.2	0.2
	2024	0.1	0.1	0.1	0.2	0.2	0.4	0.5	0.5	0.4	0.2	0.2	0.2
	2025	0.1	0.1	0.1	0.2	0.2	0.4	0.5	0.5	0.4	0.2	0.2	0.2
	2026	0.1	0.1	0.1	0.2	0.2	0.4	0.5	0.5	0.4	0.2	0.2	0.2
	2027	0.1	0.1	0.1	0.2	0.2	0.4	0.5	0.5	0.4	0.2	0.2	0.2
	2028	0.1	0.1	0.1	0.2	0.2	0.4	0.5	0.4	0.4	0.2	0.2	0.2
	2029	0.1	0.1	0.1	0.2	0.2	0.4	0.5	0.4	0.4	0.2	0.2	0.2
	2030	0.1	0.1	0.1	0.2	0.2	0.4	0.5	0.4	0.4	0.2	0.2	0.2

7.4 Comparison between Ex Post and Ex Ante

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

On average, the summer ex post impact for Rate 1 was 0.007 kW, seen in the third column of Table 7-6. However, the 2019 SDG&E 1-in-10 load impact for an average weekday is 0.011 kW, which is slightly higher due to the higher ex ante temperatures under the 1-in-10 conditions.

- First, on average, 0.007 kW was delivered by Rate 1 during summer months where mean17 was equal to 69.2 °F.

- At those temperature conditions our model predicts that Rate 1 load impacts from 4 to 9 PM will be 0.008 kW. This is very close to the ex post estimate, indicating that the model predicts well using historical weather data.
- Our ex post load impact of 0.007 kW occurred under weather conditions that were cooler than the 1-in-10 mean17 of 71.7 °F; therefore, we expect it to be smaller than the 1-in-10 ex ante load impact estimate. Indeed, that is the case – the 1-in-10 ex ante load impact is 0.011 kW, which is larger than the ex post load impact of 0.007.

Table 7-6: Comparison of Ex Post and Ex Ante Aggregate Impacts – All Rate 1 Customers (Non-NEM and NEM)

Month	Ex Post mean17 (°F)	Ex Post Impact (kW)	Ex Post Weather, Predicted Impact (kW)	1-in-2		1-in-10	
				mean17 (°F)	Impact (kW)	mean17 (°F)	Impact (kW)
January	55.8	0.005	0.005	57.7	0.005	52.9	0.004
February	52.6	0.001	0.001	54.8	0.002	53.5	0.002
March	57.3	0.001	0.001	59.3	0.002	57.8	0.001
April	61.7	0.006	0.004	60.5	0.003	63.0	0.004
May	61.5	0.004	0.002	62.6	0.003	65.0	0.004
June	65.7	0.004	0.004	64.9	0.003	68.3	0.007
July	70.5	0.008	0.008	69.3	0.007	72.2	0.009
August	71.3	0.011	0.011	71.7	0.011	73.9	0.014
September	71.6	0.010	0.011	70.3	0.010	74.7	0.014
October	67.0	0.004	0.007	65.2	0.005	69.2	0.009
November	62.9	0.005	0.004	57.8	0.002	63.2	0.005
December	56.6	0.006	0.006	54.9	0.005	53.1	0.005
Summer	69.2	0.007	0.008	68.3	0.007	71.7	0.011
Winter	58.4	0.004	0.003	58.2	0.003	58.3	0.003
Annual	62.9	0.005	0.005	62.4	0.005	63.9	0.006

Table 7-7 presents a similar comparison of ex post and ex ante estimates for Rate 2. The average ex post and predicted ex post impact in the summer months is 0.013 kW, indicating that the ex ante model accurately predicts load impacts under historical weather conditions. The same is true in the winter months and the year as a whole. Ex ante impacts are expected to be similar to ex post impacts under 1-in-2 weather conditions. Conversely, load impacts are expected to be slightly greater during 1-in-10 summer months, when temperatures are expected to be warmer than summer 2019.

Table 7-7: Comparison of Ex Post and Ex Ante Aggregate Impacts – All Rate 2 Customers (Non-NEM and NEM)

Month	Ex Post <i>mean17</i> (°F)	Ex Post Impact (kW)	Ex Post Weather, Predicted Impact (kW)	1-in-2		1-in-10	
				<i>mean17</i> (°F)	Impact (kW)	<i>mean17</i> (°F)	Impact (kW)
January	55.7	0.006	0.005	57.7	0.006	52.9	0.004
February	52.6	0.003	0.005	54.8	0.005	53.6	0.005
March	57.3	0.003	0.003	59.3	0.003	57.8	0.003
April	61.7	0.007	0.006	60.5	0.006	63.1	0.006
May	61.5	0.010	0.008	62.6	0.008	65.0	0.008
June	65.7	0.013	0.014	64.9	0.013	68.2	0.016
July	70.5	0.018	0.018	69.3	0.017	72.2	0.019
August	71.3	0.017	0.014	71.7	0.015	73.9	0.016
September	71.6	0.014	0.013	70.3	0.012	74.7	0.016
October	66.9	0.004	0.006	65.2	0.004	69.2	0.007
November	62.9	0.009	0.007	57.8	0.006	63.2	0.007
December	56.6	0.007	0.007	54.9	0.007	53.1	0.007
Summer	69.2	0.013	0.013	68.3	0.012	71.6	0.015
Winter	58.3	0.007	0.006	58.2	0.006	58.4	0.006
Annual	62.9	0.009	0.009	62.4	0.008	63.9	0.010

8 Recommendations

During SDG&E's Default TOU Pilot, a portion of customers were set aside to act as a control group in order to allow for estimation of load impacts under a Randomized Encouragement Design evaluation framework. Now that SDG&E has completed the customer transition to default TOU rates, there are no longer any customers available to serve as a valid control group to estimate load impacts under a similar evaluation framework.

This evaluation has shown that there are statistically significant impacts to customer load attributable to the TOU rates; impacts that need to be properly accounted for in utility load forecasting for resource adequacy. In the future, these changes in residential customer load could be captured in several ways. Alternative ex post evaluation approaches could be considered, or the customer load under TOU rates could be moved outside of measurement & evaluation and become integrated into the residential load forecast.



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