



2020 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 2020 load impact evaluation of San Diego Gas & Electric Company's (SDG&E) residential default time-of-use (TOU) rates. These rates were first implemented in a pilot capacity in response to California Public Utilities Commission (CPUC) Decision 15-07-001. The pilot tested two different TOU rate options: Rate 1 and Rate 2. A key objective of the pilot was to develop insights that helped 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.

SDG&E conducted the default pilot in 2018 with approximately 140,000 households being assigned to one of the two TOU rates, and an additional 170,000 retained in the study on the standard tiered rate to act as a control group. 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. Of the 140,000 customers notified of the new TOU rates, approximately 27,000 customers chose to stay on their existing rate, leaving around 113,000 customers in the TOU pilot study.

This report marks the fourth evaluation of SDG&E's residential default TOU pricing rates. 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. Most recently the third evaluation provided load impacts from the summer period of June through October 2019 are documented in the “2019 Load Impact Evaluation of San Diego Gas and Electric's Residential Default Time-of-Use Rates” dated April 1, 2020 (CALMAC Study ID SDG0325).

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 2020 (June through October 2020). This period marks the first full summer where the default TOU rates have been rolled out at a significant scale to SDG&E's residential population and a representative control group cannot be formed from the remaining non-TOU customers. Thus, the ex post methodology in this evaluation utilizes a weather-normalized pre- and post-treatment analysis instead of the

difference-in-differences approach used in prior evaluations. An additional objective of this study 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. Lastly, the summer of 2020 was unique in that from approximately March onwards, the COVID-19 pandemic led to stay-at-home orders for most residential customers and commercial shutdowns. This evaluation includes an investigation into the how reference loads and impacts for customers on TOU rates have significantly changed in 2020 due to COVID-19.

1.1 Background and Design

Figure 1-1 and Figure 1-2 show the timing of the rate periods for Rates 1 and 2 and the prices 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 periods 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 approximately 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 1¹

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 (28¢)						Off-Peak (32¢)										Peak (52¢)									
	Winter	Super Off-Peak (32¢)						Off-Peak (33¢)										Peak (34¢)									
	March - April	Super Off-Peak (32¢)						Off-Peak (33¢)												Peak (34¢)							
Weekend	Summer	Super Off-Peak (28¢)																		Peak (52¢)							
	Winter	Super Off-Peak (32¢)																		Peak (34¢)							

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 (32¢)												Peak (49¢)											
	Winter	Off-Peak (33¢)												Peak (34¢)											
Weekend	Summer	Off-Peak (32¢)												Peak (49¢)											
	Winter	Off-Peak (33¢)												Peak (34¢)											

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 defaulted onto TOU tariffs. 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

¹ Rates effective April 1, 2020, and do not reflect the baseline credit of approximately \$0.07 per kWh for usage up to 130% of baseline.

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 and Table 1-2 present the average weekday peak period load reduction for Rate 1 and Rate 2 customers, respectively. Both tables also show separate impacts for Non-NEM and NEM customers. Due to the limitations of the methodology, the load reduction estimates are not statistically significant (see Section 3.1.3 for more details). Key findings for load impacts are summarized in following the table.

Table 1-1: Rate 1 Summer Peak Period Load Reductions on Average Weekday²

Utility	Metric	Rate 1 Summer		
		All Customers	Non-NEM	NEM
SDG&E	Peak Period Hours	4-9 PM	4-9 PM	4-9 PM
	% Impact	3.3%	3.3%	4.4%
	Absolute Impact (kW)	0.03 kW	0.03 kW	0.06 kW
	Average Number of Enrolled Customers	854,576	787,881	66,695
	Number of Customers in Analysis	510,264	485,911	24,353

² 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.

Table 1-2: Rate 2 Summer Peak Period Load Reductions on Average Weekday³

Utility	Metric	Rate 2 Summer		
		All Customers	Non-NEM	NEM
SDG&E	Peak Period Hours	4-9 PM	4-9 PM	4-9 PM
	% Impact	6.4%	6.3%	17.4%
	Absolute Impact (kW)	0.07 kW	0.07 kW	0.28 kW
	Average Number of Enrolled Customers	27,544	25,076	2,468
	Number of Customers in Analysis	19,295	19,067	228

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

- Due to the majority of SDG&E's residential customers being on a TOU rate by the beginning of summer 2020, there were not enough customers remaining to create a matched control group to estimate ex post load impacts. As an alternative, Nexant performed a comparison of customers' energy usage prior to being defaulted onto a TOU rate with their energy usage after being defaulted. While this analysis yielded impact estimates that were in line with previous evaluations, the confidence intervals around these estimates are much wider than with the matched control group approach and the load impact estimates are not statistically significant. See Section 3.1.3 for additional details.
- During the summer of 2020, the average number of eligible customers for the analysis was 854,576 for Rate 1 and 27,544 for Rate 2. For the current analysis, after the additional exclusion of the NEM enrollments after the pre-treatment period and customers with insufficient pre-treatment data, the average number of customers included in the analysis was 510,264 for Rate 1 and 19,295 for Rate 2 (see Section 4).
- 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 as NEM 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 performed analysis for NEM customers who had become NEM at least one year prior to the treatment period.

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.

- On average, default customers on both Rates 1 and 2 produced peak-period load reductions in the summer months. Peak period load reductions averaged roughly 3.3% for Rate 1 and 6.3% for Rate 2 (Sections 4.2 and 4.3).
 - However, due to the limitations of the methodology, the load reduction estimates are not statistically significant.
- In the summer months, load reductions were greater for Rate 2 than for Rate 1, despite both rates having the same peak time period (4 PM to 9 PM) and Rate 1 having higher peak-period prices than Rate 2. (Sections 4.2 and 4.3).⁴
- In the summer months, the pattern of load reductions varied across climate regions. For Rate 1, the hot climate region had the largest impacts of 4.9%, while the moderate climate region showed 3.6% and the cool climate region showed 3.0%. (Sections 4.2 and 4.3).⁴ Similar results were observed in the three prior TOU rate studies that load reductions are higher in warmer climates.
- NEM customers in Rate 1 showed slightly higher peak period load impacts of 4.4% compared with the non-NEM Rate 1 population (3.3%). (Section 4.2.2).⁴

1.2.2 COVID-19 Impacts

An additional analysis was conducted to explore the effects of COVID-19 on load for customers on TOU rates. This analysis was conducted on pilot participants and those customers who were defaulted before the beginning of summer 2019. Key findings pertaining to the load impacts between summer periods for PY2019 and PY2020 for these customers include:

- On average, non-NEM default TOU customers across SDG&E's service territory on Rate 1 increased peak-period electricity use by 9%, or 0.09 kW. Average peak-period load increases range from a high of 15% and 0.25 kW in the hot climate region to a low of about 8% and 0.07 kW in the cool climate region. Rate 2 NEM customers showed load increases of 0.23 kW (17%). However, these COVID-19 load increases were not statistically significant at the 90% level of confidence.
- On average, non-NEM default TOU customers across SDG&E's service territory on Rate 2 increased peak-period electricity use by 11%, or 0.10 kW. Average peak-period load increases range from a high of 13% and 0.17 kW in the hot climate region to a low of about 10% and 0.08 kW in the cool climate region. Rate 2 NEM customers showed load increases of 0.36 kW (23%).⁴

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 and 2020 led to a large growth in the starting point for the enrollment forecast for the ex ante analysis, beginning at about 837,000 for Rate 1 and 27,000 for Rate 2 in January 2021. The TOU Enrollment onto Rate 1 is expected to grow at a rate of 0.4% per year to approximately 868,000 by 2031. After 2021, few new enrollments are anticipated for Rate 2, and the

⁴ The load impacts, and any differences in load impacts between different rates or customer segments, are not statistically significant. While not statistically significant, the findings provide a directional indication of relative performance differences between the various rates and segments.

population is expected to increase by only 0.02% per year. The Rate 2 population is expected to stay around 27,000 by 2030 (Section 6.1).

- Generally speaking, ex post and ex ante load impacts are larger under higher temperatures. As such, the largest ex ante impacts (0.021 kW per customer on Rate 1 and 0.019 kW on Rate 2) are forecasted for 1-in-10 weather conditions during the hottest summer month (August). Winter ex ante load impact estimates are expected to be similar under 1-in-2 and 1-in-10 weather conditions (Sections 6.2 and 6.3).
- In 2021, the largest aggregate ex ante impact estimates are in August under SDG&E weather scenarios. For Rate 1, they are estimated to be 17.9 MW for 1-in-2 weather conditions and 18.8 MW for 1-in-10 conditions (Section 6.2). For Rate 2, the estimates are largest in July, at 0.6 MW under both 1-in-2 and 1-in-10 weather conditions (Section 6.3).

Due to the majority of SDG&E's residential customers being on a TOU rate by the beginning of summer 2020, there were not enough customers remaining to create a matched control group to estimate ex post load impacts. In addition, the COVID-19 pandemic created an additional challenge to estimate ex post load impacts for 2020. While the revised methodology to circumvent these challenges did not produce statistically significant results, the estimates were in the expected range compared to previous evaluations. Additionally, several trends from previous evaluations were seen in the results from this study, including higher ex post load impacts for customers on Rate 2 than on Rate 1, as well as highest load reduction in the hot climate region, followed by the moderate and cool climate regions.

2 Introduction

SDG&E has two separate default TOU rate options: (TOU-DR-1) Rate 1 and (TOU-DR-2) Rate 2. The default pilot in 2018 was conducted with approximately 140,000 households being assigned to one of the two TOU rates and an additional 170,000 retained in the study on the standard tiered rate to act as a control group. 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. Of the 140,000 customers notified of the new TOU rates, approximately 27,000 customers chose to stay on their existing rate, leaving around 113,000 customers in the TOU pilot study. 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.

At the beginning of the summer of 2020, approximately 837,000 households were enrolled on one of the two TOU rates. Figure 2-1 and Figure 2-2 show total customer enrollment by month since the onset of the pilot for Rate 1 and Rate 2, respectively. The blue bars show customer counts during the pilot period while green bars show customer counts during the default period.

Figure 2-1: Rate 1 Total Enrolled Customers by Month

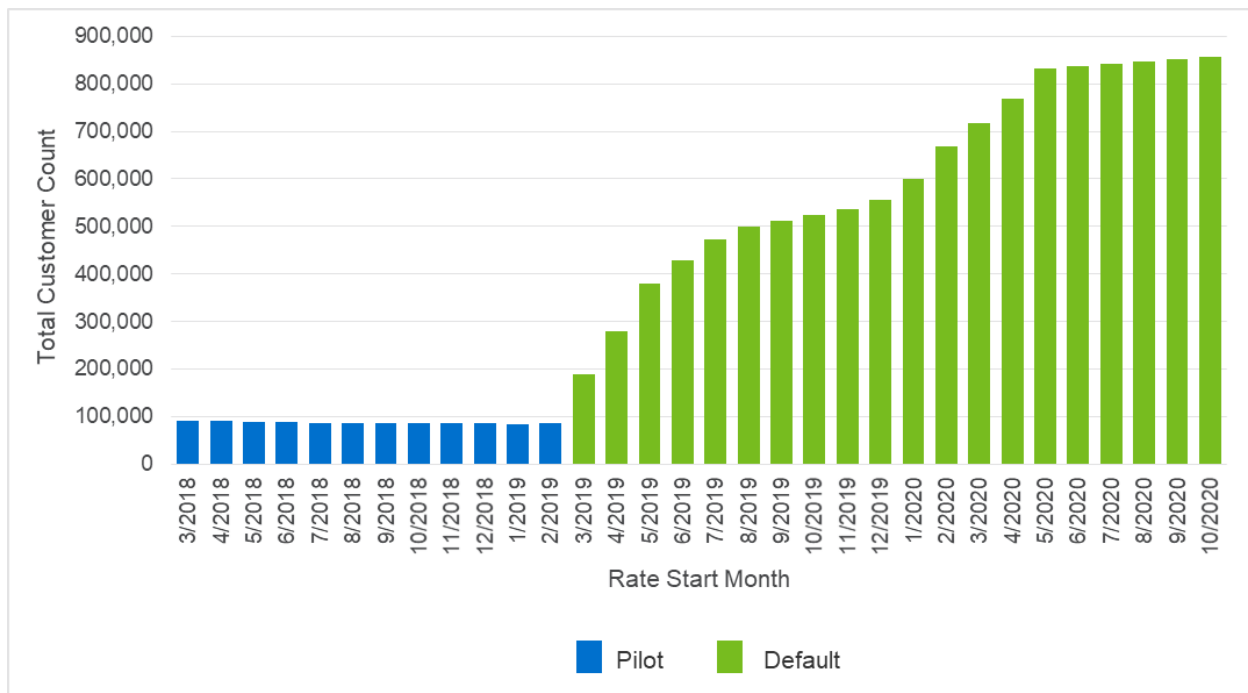
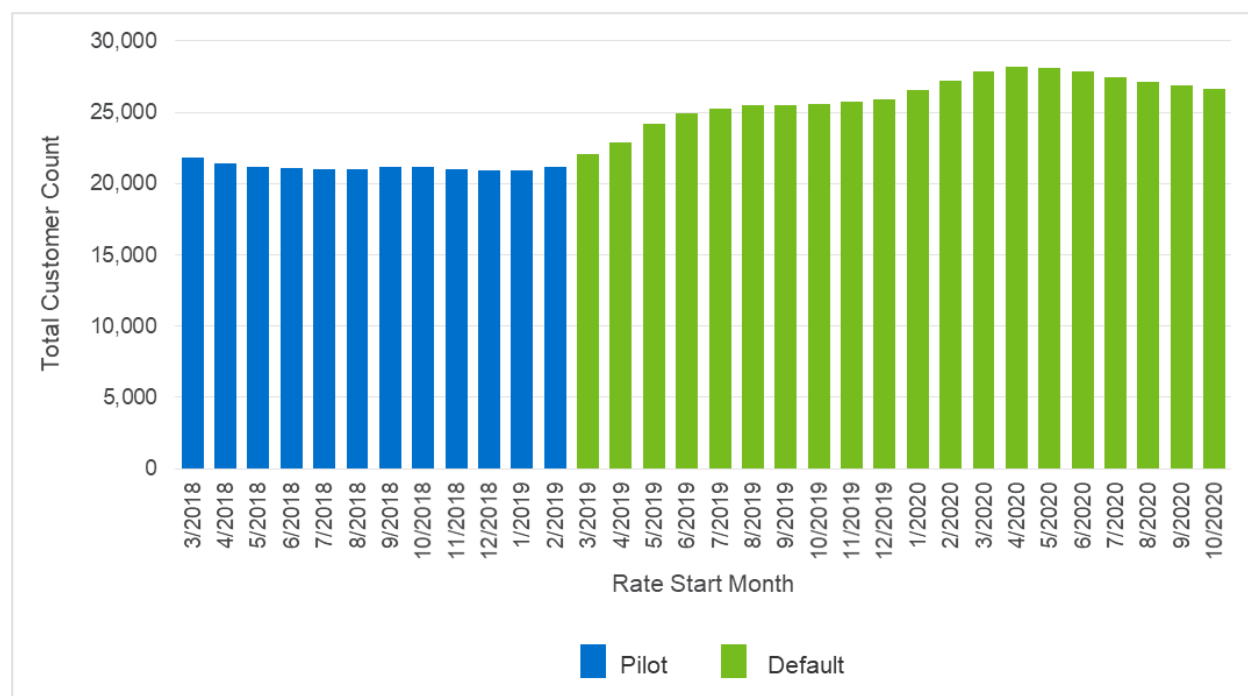


Figure 2-2: Rate 2 Total Enrolled Customers by Month

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. Most recently, load impacts from the summer period of June through October 2019 are documented in the “2019 Load Impact Evaluation of San Diego Gas and Electric’s Residential Default Time-of-Use Rates” dated April 1, 2020 (CALMAC Study ID SDG0325).

Figure 2-3 and Figure 2-4 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 approximately \$0.07/kWh that applies to each rate.

Figure 2-3: Default Pilot Rate 1⁵

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 (28¢)						Off-Peak (32¢)									Peak (52¢)								
	Winter	Super Off-Peak (32¢)						Off-Peak (33¢)									Peak (34¢)								
	March - April	Super Off-Peak (32¢)						Off-Peak (33¢)									Peak (34¢)								
Weekend	Summer	Super Off-Peak (28¢)												Peak (52¢)											
	Winter	Super Off-Peak (32¢)												Peak (34¢)											

Figure 2-4: 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 (32¢)												Peak (49¢)											
	Winter	Off-Peak (33¢)												Peak (34¢)											
Weekend	Summer	Off-Peak (32¢)												Peak (49¢)											
	Winter	Off-Peak (33¢)												Peak (34¢)											

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 approximately 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.

2.1 Evaluation Objectives

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

- Estimate hourly ex post load impacts for the summer period from June to October 2020;
- 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

⁵ Rates effective April 1, 2020, and do not reflect the baseline credit of approximately \$0.07 per kWh for usage up to 130% of baseline.

- Conduct the evaluation and produce all evaluation reporting in compliance with the California Public Utilities Commission (CPUC) Load Impact Protocols (Protocols) ⁶ and under guidance provided by the Demand Response Measurement and Evaluation Committee (DRMEC).

2.2 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 ex post impacts;
- Section 5 presents the COVID-19 impacts;
- Section 6 presents ex ante estimates; and
- Section 7 presents recommendations.

⁶ California Public Utilities Commission Decision 08-04-050 issued on April 28, 2008 with Attachment A.

3 Methodology

This report provides ex post load impacts for the summer 2020 period (June 1, 2020 through October 31, 2020), and ex ante impacts for 1-in-2 and 1-in-10 year weather conditions for 2020 through 2030. The impact of COVID-19 on energy consumption for customers who remained on a default TOU rate from the beginning of June 2019 through the end of October 2020 is also reported. 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 COVID-19 impact, 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 TOU rate are key evaluation 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 Weather-Normalized Pre- and Post-Treatment Analysis

In the previous Default TOU evaluations, a combination of matched control group and randomized encouragement design methodologies were used to evaluate SDG&E's TOU Rate 1 and Rate 2, respectively. In November 2019, SDG&E defaulted the remaining eligible residential customers which were by in large the control group used for the previous three studies. Therefore, by the summer of 2020, the majority of SDG&E's residential customers had been defaulted onto a TOU rate or chose to opt out. Because of this, there were not enough customers remaining that were not exposed to the TOU rates from which to create a valid comparison group.

To circumvent this challenge in this evaluation, participants' energy usage prior to being defaulted onto the TOU rate was compared with their energy usage after being defaulted onto the TOU rate. The comparison was weather-normalized in order to remove the impacts of varying weather characteristics in each year. This approach allowed for a meaningful estimation of load impacts in the absence of a proper comparison group while being able to utilize the majority of the data that has already been processed from the previous evaluations.

The general steps for this approach were: generating statistical estimates of usage as a function of weather, applying the resulting regression coefficients to 2020 weather conditions, and calculating the difference between weather-normalized pre-treatment and post-treatment usage values. The difference represents the change in consumption under 2020 weather conditions.

First, a degree-hour regression model was fit separately for each premise and time period. A typical regression specification of this nature is as follows:

$$kW_{i,t} = \alpha_i + \beta_{Cool} \times CDH_{i,t} + \beta_{Heat} \times HDH_{i,t} + \varepsilon_{i,t}$$

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

Variable	Description
$kW_{i,t}$	Per customer load impact for each week, for the hour h
α_i	Estimated constant
β_{Cool}	Estimated cooling parameter coefficient
β_{Heat}	Estimated heating parameter coefficient
$CDH_{i,t}$	Average cooling degree hours for each week, for the hour h
$HDH_{i,t}$	Average heating degree hours for each week, for the hour h
$\varepsilon_{i,t}$	The error term, assumed to be a mean zero and uncorrelated with any of the independent variables

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 pre-treatment and post-treatment periods for all participants. The terms $CDH_{i,t}$ and $HDH_{i,t}$ refer to the calculated cooling degree-hours or heating degree-hours at given base temperatures during the time period. Cooling or heating degree-hours are calculated as the difference between the mean temperature of the hour and a base temperature, usually 65°F. Cooling degree-hours are used if the actual temperature is above the base temperature, while heating degree-hours are used if the actual temperature is below the base temperature. A variety of base temperatures were tested, whether to use a fixed or variable degree-hour approach, and alternative temperature measurements to determine which specification performs best. Lastly, the β_{Cool} and β_{Heat} terms represent the estimated coefficients from the temperature terms.

After the optimal model was selected, the coefficients were applied to 2020 weather conditions. Lastly, load impacts for each segment were estimated by taking the difference between the weather-normalized pre-treatment and post-treatment usage values.

PY2020 is unique in that from approximately March onwards, the COVID-19 pandemic led to stay-at-home orders and commercial shutdowns. This has led to noticeable changes in residential load patterns that fall outside the explanation of seasonality. A regression model was developed that included a term to capture the increase in home occupancy and other effects of the pandemic. This approach is described in more detail in Section 3.2.

3.1.2 Ex Post Load Impact Reporting

The majority of load impact estimates reported in Section 4 are based on a comparison of customer loads before and after treatment. Estimates for customer segments and climate regions are developed by first partitioning the customers 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.⁷ 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. Load impacts are presented in both nominal (kW) and proportional (%) terms.

3.1.3 Limitations of Ex Post Load Impacts Methodology

Due to the majority of SDG&E's residential customers being on a TOU rate by the beginning of summer 2020, there were not enough customers remaining to create a matched control group to estimate ex post load impacts. As an alternative, customers' energy usage prior to being defaulted onto a TOU rate was compared with their energy usage after being defaulted. However, there are limitations with the regression-based approach that do not exist when comparing treatment customers to a control group.

In the matched control group methodology, customers in both treatment and control groups experience the same conditions except for exposure to the TOU rate. With an appropriately selected matched control group, exogenous influences such as weather and COVID-19 are inherently controlled for. This means when energy usage is compared across groups, the difference can be attributed to the treatment effect, i.e., the TOU load impact. Use of validated control groups has been shown to consistently outperform alternative baseline methodologies in estimating load reductions with low bias and high precision.

There are a number of factors that cause a customer's energy usage to change before and after defaulting onto a TOU rate besides the effect of the rate itself. The regression-based approach used in this evaluation aims to isolate the TOU load impact by removing the effects of varying conditions between the pre-treatment and the PY2020 post-treatment period. For each measurable condition, such as outdoor air temperature, the influence on a customer's energy usage can be estimated using a regression model. However, there are two primary limitations with this method.

First, the regression model only approximates the influence from each of these varying conditions. The accuracy of the model depends on how well changes in customers' energy

⁷ http://www.calmac.org/events/FinalDecision_AttachmentA.pdf

usage are explained by changes in the measurable conditions (e.g., increasing air conditioning load when outdoor air temperature increases). For customers with very consistent energy usage behaviors that closely match the measurable conditions, the model can predict energy usage quite well. However, for many customers, the relationship between energy usage and these measurable influences is not well-aligned, which decreases the accuracy of the model (increases error). Further, PY2020 is unique in that from approximately March onwards, the COVID-19 pandemic caused noticeable changes in residential load patterns that fall outside the explanation of seasonality. While the regression model included a term to capture the increase in home occupancy and other effects of the pandemic, model accuracy varied across the customer population.

Second, not all of the varying conditions between the pre-treatment and post-treatment periods can be measured and fit in a regression model, such as changes in customers' behavior and energy efficiency improvements. The time between the pre-treatment and post-treatment periods ranges from at least one year up to three years apart depending on when the customer started on the TOU rate, meaning the influence from these unmeasurable changes can be significant.

Based on previous evaluations, the average weekday TOU load impacts during the summer peak period ranged from -0.01 kW to 0.01 kW (-0.6% to 1.8% impact) depending on the rate and customer segment. This TOU effect is much smaller compared to the influence of weather and the COVID-19 pandemic on customer energy consumption, which means the error in the modeling approach could not extract statistically significant ex post load impacts.

3.2 COVID-19 Assessment Methodology

It is important to investigate whether consumption for customers on TOU rates has significantly changed between 2019 and 2020 due to COVID-19. When analyzing the COVID-19 effect, it is important to compare loads for the same group of customers over time. A comparison of customers enrolled in one year with those enrolled in the following year is not a valid estimate of COVID-19 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 years.

As such, load impacts for the COVID-19 analysis pertained to the populations of customers that remained enrolled on TOU rates over the same time periods. Pilot participants and those customers who were defaulted before the beginning of summer 2019 were analyzed for changes to loads in summer periods for PY2019 and PY2020.

The overall approach for this task was very similar to the ex post load impacts methodology, except instead of isolating the TOU effect from changes in weather from one year to another, this isolates the COVID-19 effect from changes in weather. As such, the same limitations of the ex post load impacts methodology described in Section 3.1.3 also apply to the COVID-19 assessment. The general steps for this approach were: generating statistical estimates of usage as a function of weather, applying the resulting regression coefficients to 2020 weather conditions, and calculating the difference between weather-normalized post-treatment usage values before and during the pandemic. The difference represents the change in consumption due to COVID-19 under 2020 weather conditions.

First, a weather-based regression model was fit separately for each premise and time period, similar to the ex post load impacts methodology. To represent the change in usage associated with COVID-19, an additional variable was added to capture months during the pandemic. A typical regression specification of this nature is as follows:

$$kW_{i,t} = \alpha_i + \beta_{Cool} \times CDH_{i,t} + \beta_{Heat} \times HDH_{i,t} + \beta_{COVID} \times COVID_{i,t} + \varepsilon_{i,t}$$

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

Variable	Description
$kW_{i,t}$	Per customer load impact for each week, for the hour h
α_i	Estimated constant
β_{Cool}	Estimated cooling parameter coefficient
β_{Heat}	Estimated heating parameter coefficient
β_{COVID}	Estimated COVID-19 impact parameter coefficient
$CDH_{i,t}$	Average cooling degree hours for each week, for the hour h
$HDH_{i,t}$	Average heating degree hours for each week, for the hour h
$COVID_{i,t}$	A binary indicator for each month for which COVID-19 impacts apply
$\varepsilon_{i,t}$	The error term, assumed to be a mean zero and uncorrelated with any of the independent variables

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 contains electricity usage data during the post-treatment periods for all participants in 2019 and 2020, with flags for each month of the pandemic. The COVID-19 binary flags for impact on residential customer load were provided by SDG&E and are shown in Table 3-3.

Table 3-3: Monthly COVID-19 Binary Variable

Month	2019	2020	2021	2022
January	0.00	0.00	0.93	0.00
February	0.00	0.00	0.85	0.00
March	0.00	0.00	0.78	0.00
April	0.00	1.00	0.71	0.00
May	0.00	1.00	0.64	0.00
June	0.00	1.00	0.56	0.00
July	0.00	1.00	0.49	0.00
August	0.00	1.00	0.42	0.00
September	0.00	1.00	0.35	0.00
October	0.00	1.00	0.27	0.00
November	0.00	1.00	0.20	0.00
December	0.00	1.00	0.20	0.00

A variety of temperature measurements were tested to determine which specification performs best. After the optimal model was selected, the resulting hourly coefficients for the COVID-19 variable were extracted for each rate and customer segment. This hourly coefficient, when multiplied by the COVID-19 binary variable (equal to 1.00 starting April 2020 and ramping back down to 0.00 by January 2022), represents the impact of the COVID-19 pandemic on customer's load. The coefficient was used to adjust the reference load to 2020 conditions for the ex post impacts analysis as well as ex ante forecasts through the end of 2021.

The outcomes of this analysis helped to inform the potential COVID-19 influence that is observed from the differences in load between 2019 and 2020 for the general population defaulted onto the TOU rates who are experiencing TOU and COVID-19 influences at the same time.

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 profiles used for ex ante load impact estimation are meant to reflect 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.⁸ 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.

Due to the limitations of the ex post methodology detailed in Section 3.1.3, the ex ante approach was modified to incorporate impacts from previous evaluations performed with control groups,

⁸ 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.

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

- First, assess how ex post reference loads in each hour from November 2019 through October 2020 vary, by segment, as a function of weather conditions using the weather-normalization regression methodology described in Section 3.1;
- Next, the hourly percentage impacts for each segment are estimated by taking a weighted average of ex post results from the pilot customers and newly defaulted customers in PY2019;
- Then, the estimated reference loads are combined with the percentage impacts and the relationship between reference loads, impacts and temperature is estimated for each hour of the day, each season (summer/winter) and each rate by segment;
- Finally, 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. Aggregate impacts are generated using the enrollment forecast provided by SDG&E.

3.3.1 Estimating Ex Ante Weather Conditions

The CPUC Load Impact Protocols⁹ (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.

⁹ See CPUC Rulemaking (R.) 07-01-041 Decision (D.) 08-04-050, "Adopting Protocols for Estimating Demand Response Load Impacts" and Attachment A, "Protocols."

3.3.2 Estimating Ex Ante Load Impacts

Ex ante impact estimates were calculated by incorporating ex post percentage load impacts from the most recent evaluations of SDG&E D-TOU customers. Nexant conducted evaluations in PY2019 for both the pilot customers and the first group of mass default customers. Both of these evaluations benefited from making use of a control group methodology, allowing for impact estimates that feature a much higher level of confidence than the current ex post evaluation. The normalized reference loads from the current evaluation were combined with these population-weighted percentage impacts to generate predictions for ex ante weather conditions using a regression model. The ex ante model specification takes as its dependent variable the average hourly impact and reference load for each month from November 2019 through October 2020. 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 3-1.¹⁰

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

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

Table 3-4: Description of Ex Ante Load Impact Regression Variables

Variable	Description
$Impact_h$	Per customer 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

The coefficients from the regression are applied to the ex ante weather scenarios described in the previous section. This produces per-customer estimates of reference and treatment loads for both 1-in-2 and 1-in-10 operating conditions for both average weekdays and monthly system peak days. Lastly, the enrollment forecast provided by SDG&E, which covers each month in 2021 through 2031, is combined with these estimates to generate aggregate ex ante impact estimates throughout the forecast horizon. The effect of COVID-19 on reference loads is accounted for by using the results detailed in Section 4 combined with a monthly “timing” factor

¹⁰ 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.

provided by SDG&E to create an overall COVID-19 effect. This effect is applied on a monthly basis according to the schedule shown in Table 3-3.

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.

4 Ex Post Load Impacts

This report section summarizes the load impacts for the two rate treatments tested by SDG&E. 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 default through October 2020, by climate region (hot, moderate, and cool) and CARE/FERA status, referred to as “non-NEM” customers. Throughout summer 2020, there was an average of 787,881 enrolled customers that fell into this category. After data cleaning, the final analysis used an average of 485,911 customers.
- Customers who have been net energy-metered (NEM) since at least 12 months before default, referred to as “NEM” customers. Throughout summer 2020, there was an average of 66,695 enrolled customers that fell into this category. After data cleaning and excluding customers that became NEM after 12 months prior to being defaulted onto Rate 1, the final analysis used an average of 24,353 customers.

Rate 2:

- Customers who were never net energy-metered (NEM) from 12 months before default through October 2020, by climate region (hot, moderate, and cool) and CARE/FERA status, referred to as “non-NEM” customers. Throughout summer 2020, there was an average of 25,076 enrolled customers that fell into this category. After data cleaning, the final analysis used an average of 19,067 customers.
- Customers who have been net energy-metered (NEM) since at least 12 months before default, referred to as “NEM” customers. Throughout summer 2020, there was an average of 2,468 enrolled customers that fell into this category. After data cleaning and excluding customers that became NEM after 12 months prior to being defaulted onto Rate 2, the final analysis used an average of 228 customers.

Customers were segmented into those who were NEM at least 12 months before default and those who were not. The ex post analysis focused on these two sets of customers. Those customers who became NEM after being defaulted onto the TOU rates are excluded from the analysis presented in this section. This resulted in the exclusion of approximately 42,342 customers in Rate 1 and 2,240 customers in Rate 2 from the analysis.

It is imperative that comparisons across climate regions are cognizant of the differences in the mix of customers across regions. That is, because CARE/FERA customers were not defaulted onto TOU rates 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 primarily 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 2020. Impacts are reported for each rate, customer segment, and climate region summarized above.

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.

4.1 Summary of Time-of-Use Rates

Figure 2-3 and Figure 2-4 in Section 2 summarize 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 approximately \$0.07/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 (49¢/kWh for Rate 2 versus 52¢/kWh for Rate 1) and the same peak price in winter months (34¢/kWh). The off-peak price for Rate 2 is 32¢/kWh during the summer months which represents a peak to off-peak price ratio of 1.5 to 1. The winter season for both rates runs from November 1 through May 31.

4.2 Rate 1

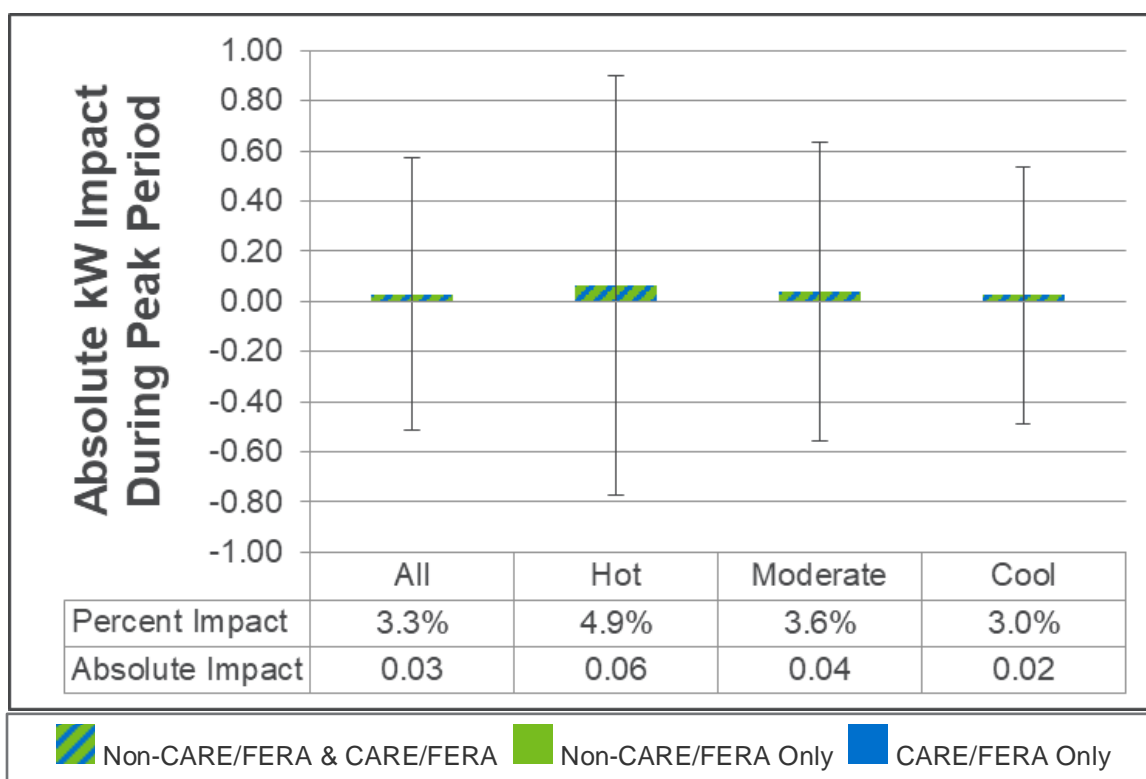
This section presents load impacts for Rate 1 TOU customers who never became NEM while on the rate, as well as load impacts for customers who had become NEM prior to 12 months before being defaulted onto the rate. Load impacts are presented at the overall level, as well as by climate region and CARE/FERA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

4.2.1 Load Impacts for Non-NEM Customers by Customer Segment

Figure 4-1 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.¹¹ In these cases, t-tests were calculated to determine whether the difference is statistically significant.¹²

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.

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



As seen in Figure 4-1, the average peak-period load impacts for the service territory as a whole and for the three climate regions are not statistically significant at the 90% level of confidence. On average, default TOU customers across SDG&E's service territory on Rate 1 reduced peak-

¹¹ For further discussion of this topic, see <https://www.cscu.cornell.edu/news/statnews/stnews73.pdf>.

¹² The test was applied at the 90% confidence level which means that a t-value exceeding 1.65 indicates statistical significance.

period electricity use by 3.3%, or 0.03 kW, across the five hour peak period from 4 PM to 9 PM. Average peak-period load reduction ranges from a high of 4.9% and 0.06 kW in the hot climate region to a low of about 3.0% and 0.02 kW in the cool climate region. These percent and absolute impacts are comparable with the summer 2019 evaluation of newly defaulted customers, which showed an overall impact of 2.2% and 0.02 kW. However, as described in Section 3.1.3, the limitations of the ex post methodology in the absence of an available control group result in a large degree of uncertainty around the impact estimates.

Table 4-1 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 4-1, which represent the load impacts in the peak period on the average weekday, equal the values shown in Figure 4-1, discussed above.

Table 4-1: 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)

Day Type	Period	Hours	Rate 1											
			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	0.89	0.03	3.3%	1.29	0.06	4.9%	1.02	0.04	3.6%	0.80	0.02	3.0%
	Off-Peak	6 AM to 4 PM and 9 PM to 12 AM	0.67	0.01	1.3%	0.94	0.02	1.9%	0.75	0.01	1.0%	0.62	0.01	1.4%
	Super Off-Peak	12 AM to 6 AM	0.47	<0.01	1.1%	0.60	<0.01	0.4%	0.50	0.01	1.2%	0.44	<0.01	1.0%
	Day	All Hours	0.66	0.01	1.8%	0.93	0.02	2.5%	0.74	0.01	1.8%	0.61	0.01	1.8%
Average Weekend	Peak	4 PM to 9 PM	0.93	0.04	4.5%	1.39	0.09	6.7%	1.08	0.05	4.8%	0.84	0.04	4.2%
	Off-Peak	2 PM to 4 PM and 9 PM to 12 AM	0.83	0.02	2.4%	1.14	0.04	3.3%	0.94	0.02	2.2%	0.75	0.02	2.6%
	Super Off-Peak	12 AM to 2 PM	0.59	0.01	2.0%	0.84	0.01	1.4%	0.66	0.01	2.0%	0.55	0.01	2.1%
	Day	All Hours	0.71	0.02	2.8%	1.02	0.03	3.3%	0.80	0.02	2.8%	0.65	0.02	2.8%
Monthly System Peak	Peak	4 PM to 9 PM	1.27	0.08	6.4%	1.76	0.16	9.2%	1.52	0.10	6.5%	1.11	0.07	6.3%
	Off-Peak	6 AM to 4 PM and 9 PM to 12 AM	0.93	0.05	5.4%	1.28	0.06	4.7%	1.07	0.05	4.4%	0.83	0.05	6.2%
	Super Off-Peak	12 AM to 6 AM	0.61	0.07	12.0%	0.75	0.06	8.5%	0.67	0.08	12.0%	0.57	0.07	12.1%
	Day	All Hours	0.92	0.06	6.8%	1.25	0.08	6.6%	1.07	0.07	6.2%	0.83	0.06	7.2%

* A shaded cell indicates estimate is not statistically significant

The reference loads shown in Table 4-1 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 0.89 kW for the SDG&E territory as a whole, and around 0.66 kW for the 24-hour average weekday. In the hot climate region the average usage during the peak period is higher (1.29 kW) than in the moderate climate region (1.02 kW) or cool climate region (0.80 kW).

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 2020. 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 4-1, peak-period load reductions were not statistically significant for all climate regions and day types. In the off-peak (or shoulder) period, which varied in timing and length between weekdays and weekends, load reductions were lower than other periods in all climate regions and day types. In the super off-peak period, which runs from midnight to 6 AM, load reductions were not statistically significant for the overall and three climate regions, for 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 4-2 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, but the differences were not statistically significant. The greatest load reductions came from all combined non-CARE/FERA and CARE/FERA customers in the hot climate region, at 4.9% and 0.06 kW. The smallest load reductions are from the CARE/FERA customers in the moderate climate region with 0.7% and 0.01 kW (this impact was not statistically significant).

Figure 4-2: Average Peak Period Impacts for SDG&E Rate 1 by Climate Region & CARE/FERA Status – Non-NEM
(Positive values represent load reductions)

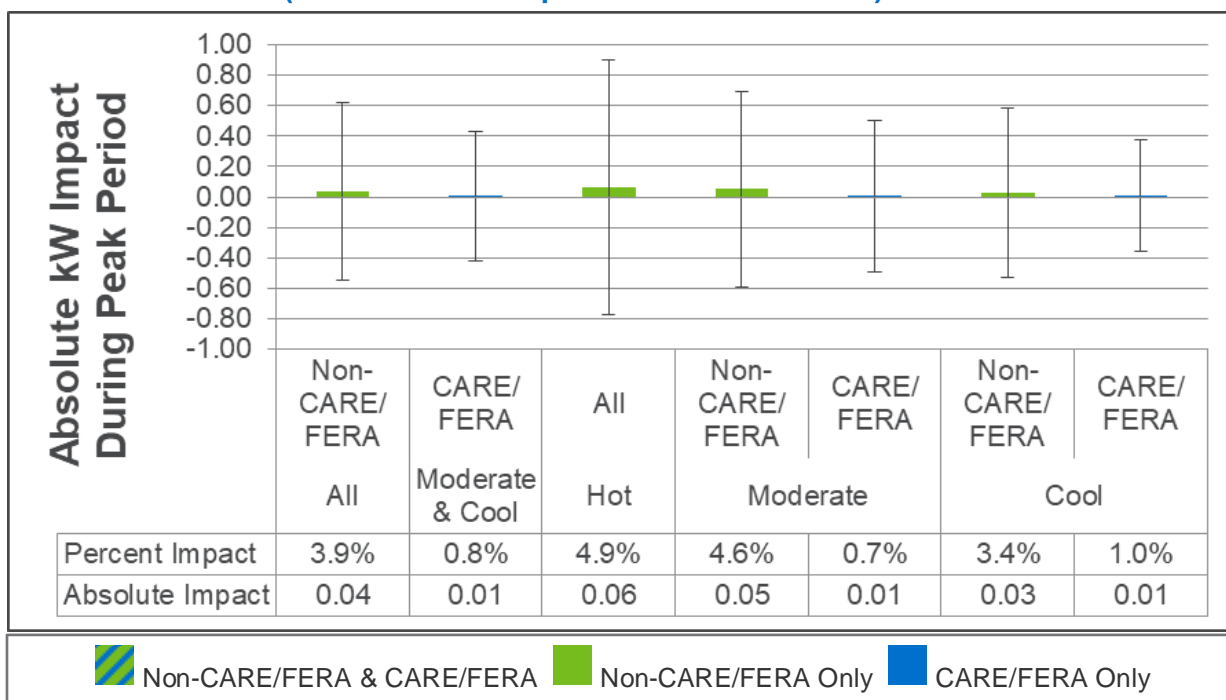


Table 4-2 shows the estimated load impacts for each rate period and day type for the service territory as a whole and by climate region for non-CARE/FERA customers and Table 4-3 shows the impacts for CARE/FERA customers. The hot climate region in Table 4-2 and Table 4-3

display N/A values as the customers in the hot region were not separated by CARE/FERA status for this analysis.

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 1.08 kW and 0.84 kW for non-CARE/FERA customers and 0.90 kW and 0.64 kW for CARE/FERA customers, respectively. None of the impacts for CARE/FERA and non-CARE/FERA customers were statistically significant.

Table 4-2: 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	0.92	0.04	3.9%	NA	NA	NA	1.08	0.05	4.6%	0.84	0.03	3.4%
	Off-Peak	6 AM to 4 PM and 9 PM to 12 AM	0.70	0.01	1.7%	NA	NA	NA	0.78	0.01	1.6%	0.66	0.01	1.7%
	Super Off-Peak	12 AM to 6 AM	0.48	0.01	1.2%	NA	NA	NA	0.52	0.01	1.4%	0.46	0.01	1.1%
	Day	All Hours	0.69	0.02	2.2%	NA	NA	NA	0.78	0.02	2.4%	0.64	0.01	2.1%
Average Weekend	Peak	4 PM to 9 PM	0.98	0.05	5.2%	NA	NA	NA	1.14	0.07	5.8%	0.89	0.04	4.7%
	Off-Peak	2 PM to 4 PM and 9 PM to 12 AM	0.86	0.03	3.0%	NA	NA	NA	0.99	0.03	3.0%	0.79	0.02	3.0%
	Super Off-Peak	12 AM to 2 PM	0.62	0.01	2.3%	NA	NA	NA	0.69	0.02	2.4%	0.58	0.01	2.3%
	Day	All Hours	0.74	0.02	3.3%	NA	NA	NA	0.84	0.03	3.5%	0.69	0.02	3.1%
Monthly System Peak	Peak	4 PM to 9 PM	1.35	0.10	7.4%	NA	NA	NA	1.63	0.13	7.9%	1.19	0.08	7.1%
	Off-Peak	6 AM to 4 PM and 9 PM to 12 AM	0.98	0.06	6.0%	NA	NA	NA	1.14	0.06	5.1%	0.89	0.06	6.7%
	Super Off-Peak	12 AM to 6 AM	0.63	0.08	12.3%	NA	NA	NA	0.68	0.08	12.2%	0.59	0.07	12.4%
	Day	All Hours	0.97	0.07	7.5%	NA	NA	NA	1.13	0.08	7.0%	0.88	0.07	7.8%

* A shaded cell indicates estimate is not statistically significant

Table 4-3: 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	0.76	0.01	0.8%	NA	NA	NA	0.90	0.01	0.7%	0.64	0.01	1.0%
	Off-Peak	6 AM to 4 PM and 9 PM to 12 AM	0.58	>-0.01	-0.3%	NA	NA	NA	0.67	>-0.01	-0.6%	0.50	<0.01	0.2%
	Super Off-Peak	12 AM to 6 AM	0.42	<0.01	0.5%	NA	NA	NA	0.47	<0.01	0.8%	0.37	<0.01	0.3%
	Day	All Hours	0.58	<0.01	0.2%	NA	NA	NA	0.67	>-0.01	0.0%	0.50	<0.01	0.4%
Average Weekend	Peak	4 PM to 9 PM	0.78	0.01	1.8%	NA	NA	NA	0.92	0.02	2.0%	0.65	0.01	1.6%
	Off-Peak	2 PM to 4 PM and 9 PM to 12 AM	0.71	<0.01	0.5%	NA	NA	NA	0.84	<0.01	0.3%	0.60	<0.01	0.7%
	Super Off-Peak	12 AM to 2 PM	0.51	<0.01	1.0%	NA	NA	NA	0.59	0.01	1.0%	0.45	<0.01	0.9%
	Day	All Hours	0.61	0.01	1.1%	NA	NA	NA	0.71	0.01	1.1%	0.52	0.01	1.0%
Monthly System Peak	Peak	4 PM to 9 PM	1.03	0.02	2.4%	NA	NA	NA	1.27	0.03	2.4%	0.83	0.02	2.4%
	Off-Peak	6 AM to 4 PM and 9 PM to 12 AM	0.77	0.02	2.9%	NA	NA	NA	0.93	0.02	2.5%	0.64	0.02	3.4%
	Super Off-Peak	12 AM to 6 AM	0.55	0.06	11.2%	NA	NA	NA	0.63	0.07	11.7%	0.48	0.05	10.6%
	Day	All Hours	0.77	0.03	4.2%	NA	NA	NA	0.93	0.04	4.0%	0.64	0.03	4.5%

* A shaded cell indicates estimate is not statistically significant

4.2.2 Load Impacts for NEM Customers

For this analysis, NEM customers are defined to be customers who were net metered prior to 12 months before going onto Rate 1 through the end of the third summer (October 2020).

Customers who became net metered any time after going onto Rate 1 are excluded from the analysis presented here. Figure 4-3 presents average summer weekday peak period load reductions for net metered (NEM) customers. These NEM customers showed load decreases of 0.06 kW (4.4%), but the positive impacts are not statistically significant. Figure 4-3 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 4-3: Average Peak Period Load Impacts for SDG&E Rate 1 by NEM Status
 (Positive values represent load reductions)

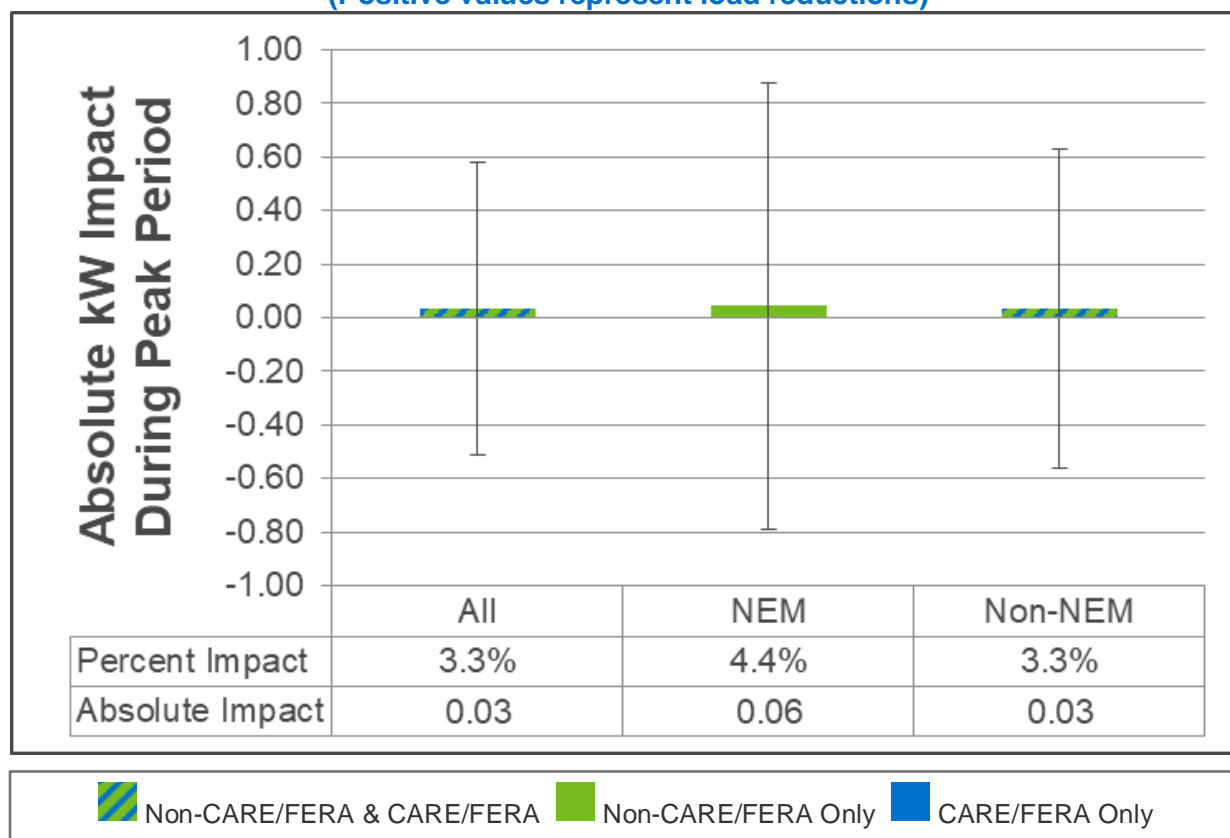
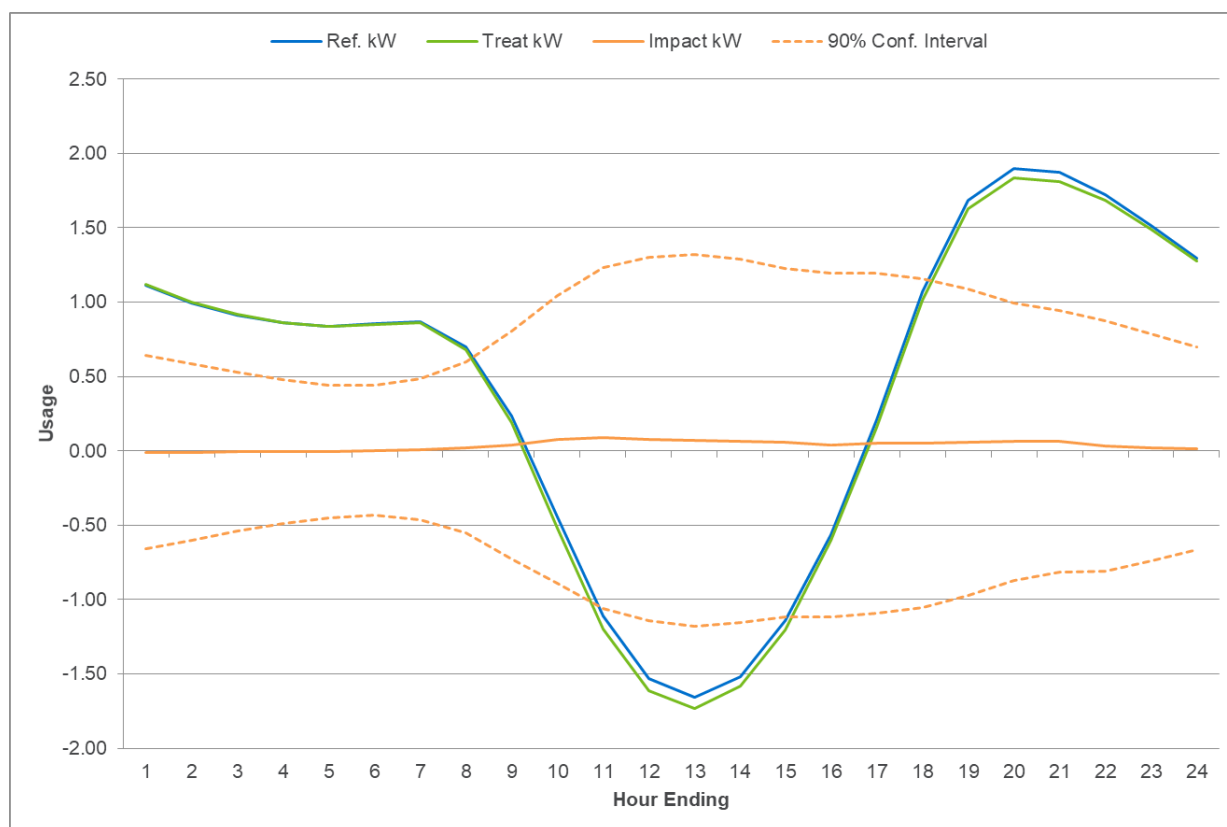


Figure 4-4 shows the daily reference and treatment loads for Rate 1 NEM customers on the average weekday during summer 2020. Treatment load is slightly lower from hours ending 7 through the end of the day, leading to positive load impacts of 0.06 kW and 0.05 kW during the peak and off-peak periods, respectively.

Figure 4-4: Average Weekday Summer Daily Load Impacts for SDG&E Rate 1 - NEM

4.3 Rate 2

This section presents load impacts for Rate 2 TOU customers who never became NEM during their TOU enrollment. Load impacts are presented at the overall level, as well as by climate region and CARE/FERA status.

4.3.1 Load Impacts for Non-NEM Customers by Customer 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 49 ¢/kWh in the peak period and 32 ¢/kWh in the off-peak period. Like Rate 1, a credit of 7 ¢/kWh is applied to usage below 130% of the baseline quantity.

Figure 4-5 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, 6.3% or 0.07 kW, are larger than those for Rate 1 (3.3% or 0.03 kW), but the difference in both absolute and percentage terms is not statistically significant. This was the same trend observed in the summers of both 2018 and 2019. Customers in the hot climate region had the largest peak period load impacts of 9.7% or 0.16 kW. However, impacts in the hot climate region are not statistically significantly greater than those in the cool and moderate climate regions. The moderate climate region showed impacts equal to about 5.9% or 0.07 kW, while the cool climate region showed 6.5% or 0.06 kW, but again these results are not statistically significant.

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

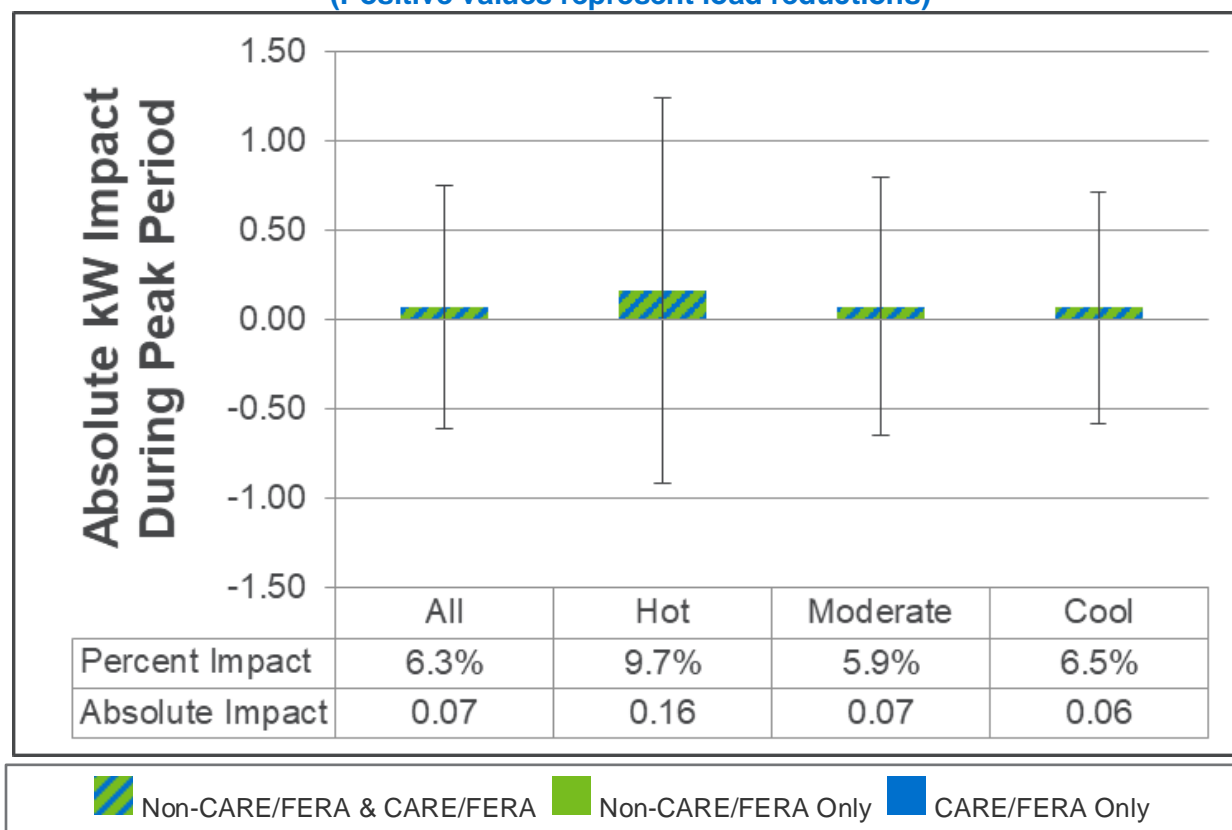


Table 4-4 presents estimates of load impacts for all relevant rate periods and day types for Rate 2 at the service territory and climate region level. Average reference load usage was 1.04 at the overall level during the peak period on the average weekday. The highest demand estimates were observed in the hot climate region on monthly system peak days during the peak period with a reference load of 2.41 kW.

For the average weekday, average weekend, and monthly system peak days, there were load reductions during the peak and off-peak periods in every climate region and at the service territory level, but the results were not statistically significant.

The largest load reduction of 17.4%, or 0.42 kW, occurred in the hot climate region during the peak period on the average monthly system peak day. However, the confidence bands on this estimate are wide and this load impact estimate is highly uncertain.

Table 4-4: 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	1.04	0.07	6.3%	1.65	0.16	9.7%	1.16	0.07	5.9%	0.95	0.06	6.5%
	Off-Peak	9 PM to 4 PM	0.69	0.02	2.2%	0.95	0.05	5.1%	0.73	0.01	1.3%	0.65	0.02	2.8%
	Day	All Hours	0.76	0.03	3.4%	1.10	0.07	6.6%	0.82	0.02	2.6%	0.72	0.03	3.9%
Average Weekend	Peak	4 PM to 9 PM	1.09	0.07	6.5%	1.74	0.19	10.6%	1.22	0.08	6.7%	0.99	0.06	6.3%
	Off-Peak	9 PM to 4 PM	0.74	0.02	2.9%	1.06	0.08	7.1%	0.79	0.02	2.2%	0.69	0.02	3.4%
	Day	All Hours	0.81	0.03	3.9%	1.20	0.10	8.2%	0.88	0.03	3.5%	0.76	0.03	4.2%
Monthly System Peak Day	Peak	4 PM to 9 PM	1.51	0.12	8.2%	2.41	0.42	17.4%	1.75	0.13	7.7%	1.34	0.11	8.4%
	Off-Peak	9 PM to 4 PM	0.92	0.05	4.9%	1.33	0.10	7.7%	1.02	0.03	3.2%	0.86	0.05	6.3%
	Day	All Hours	1.05	0.06	5.9%	1.55	0.17	10.8%	1.17	0.05	4.6%	0.96	0.07	6.9%

* A shaded cell indicates estimate is not statistically significant

Figure 4-6 shows the peak-period load reductions on weekdays for non-CARE/FERA and CARE/FERA customers. Non-CARE/FERA customers in the service territory had greater percent impacts (6.8% and 0.07 kW) than the combined moderate and cool climate region for CARE/FERA (3.2% and 0.03 kW), but these differences are not statistically significant in absolute nor percentage terms. CARE/FERA customers also had smaller load impacts in the cool and moderate climate regions, compared to the non-CARE/FERA segments, but again these results are not statistically significant.

Figure 4-6: Average Peak Period Impacts for SDG&E Rate 2 by Climate Region & CARE/FERA Status
(Positive values represent load reductions)

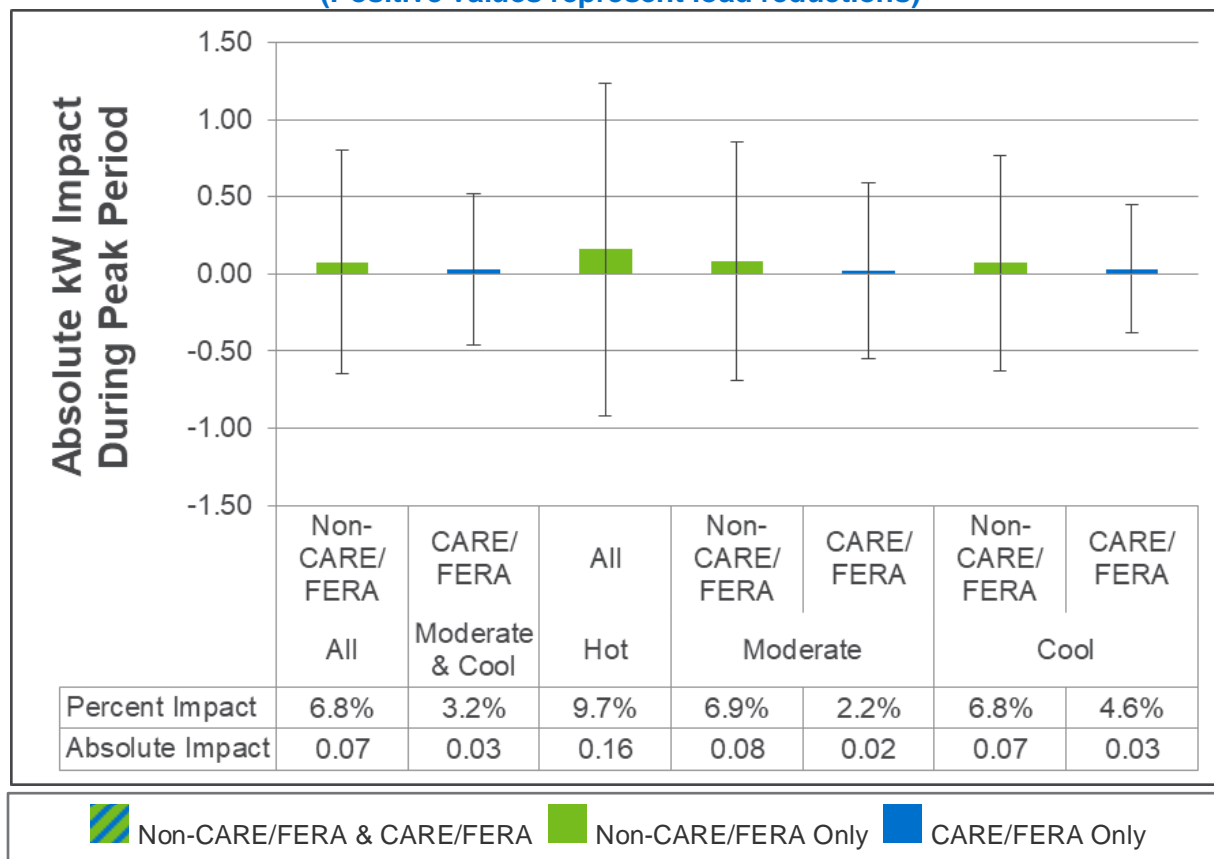


Table 4-5 and Table 4-6 show the load impacts for each rate period and day type for Rate 2 at the service territory level and across climate regions for non-CARE/FERA and CARE/FERA customers, respectively. Non-CARE/FERA customers had higher average load and load reductions during peak periods across all climate regions on average weekdays, weekends and monthly system peak days. Similar to Rate 1, the hot climate region in Table 4-5 and Table 4-6 display N/A values as the customers in the hot region were not separated by CARE/FERA status for this analysis.

Non-CARE/FERA customers had load decreases during the peak and off-peak periods for in all climate regions for average weekdays, average weekends, and average monthly system peak days. This was also true for CARE/FERA customers in all climate regions. 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 4-5: 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	1.10	0.07	6.8%	NA	NA	NA	1.23	0.08	6.9%	1.01	0.07	6.8%
	Off-Peak	9 PM to 4 PM	0.72	0.02	2.3%	NA	NA	NA	0.77	0.01	1.6%	0.69	0.02	2.8%
	Day	All Hours	0.80	0.03	3.6%	NA	NA	NA	0.86	0.03	3.2%	0.76	0.03	4.0%
Average Weekend	Peak	4 PM to 9 PM	1.15	0.08	7.1%	NA	NA	NA	1.30	0.10	7.7%	1.06	0.07	6.6%
	Off-Peak	9 PM to 4 PM	0.77	0.02	3.1%	NA	NA	NA	0.83	0.02	2.5%	0.73	0.03	3.5%
	Day	All Hours	0.85	0.04	4.2%	NA	NA	NA	0.93	0.04	4.0%	0.80	0.03	4.4%
Monthly System Peak Day	Peak	4 PM to 9 PM	1.62	0.14	8.9%	NA	NA	NA	1.88	0.17	8.8%	1.45	0.13	9.0%
	Off-Peak	9 PM to 4 PM	0.98	0.05	5.4%	NA	NA	NA	1.07	0.04	3.7%	0.91	0.06	6.7%
	Day	All Hours	1.11	0.07	6.5%	NA	NA	NA	1.24	0.07	5.3%	1.02	0.08	7.4%

* A shaded cell indicates estimate is not statistically significant

Table 4-6: 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	0.81	0.03	3.2%	NA	NA	NA	0.95	0.02	2.2%	0.68	0.03	4.6%
	Off-Peak	9 PM to 4 PM	0.55	0.01	1.3%	NA	NA	NA	0.63	<0.01	0.1%	0.48	0.01	2.8%
	Day	All Hours	0.61	0.01	1.8%	NA	NA	NA	0.69	<0.01	0.7%	0.52	0.02	3.3%
Average Weekend	Peak	4 PM to 9 PM	0.82	0.03	3.4%	NA	NA	NA	0.97	0.03	2.8%	0.68	0.03	4.0%
	Off-Peak	9 PM to 4 PM	0.58	0.01	1.9%	NA	NA	NA	0.67	0.01	1.0%	0.50	0.02	3.0%
	Day	All Hours	0.63	0.01	2.3%	NA	NA	NA	0.73	0.01	1.5%	0.54	0.02	3.3%
Monthly System Peak Day	Peak	4 PM to 9 PM	1.10	0.04	3.5%	NA	NA	NA	1.34	0.04	3.1%	0.87	0.04	4.1%
	Off-Peak	9 PM to 4 PM	0.71	0.01	2.0%	NA	NA	NA	0.83	0.01	1.0%	0.59	0.02	3.4%
	Day	All Hours	0.79	0.02	2.5%	NA	NA	NA	0.94	0.02	1.6%	0.65	0.02	3.6%

* A shaded cell indicates estimate is not statistically significant

4.3.2 Load Impacts for NEM Customers

For this analysis, NEM customers are defined to be customers who were net metered prior to 12 months before going onto Rate 2 through the end of the third summer (October 2020). Customers who became net metered any time after going onto Rate 2 are excluded from the analysis presented here. Figure 4-7 presents average summer weekday peak period load reductions for net metered (NEM) customers. These NEM customers showed load decreases of 0.28 kW (17.4%), but the positive impacts are not statistically significant. Figure 4-7 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 4-7: Average Peak Period Load Impacts for SDG&E Rate 2 by NEM Status
(Positive values represent load reductions)

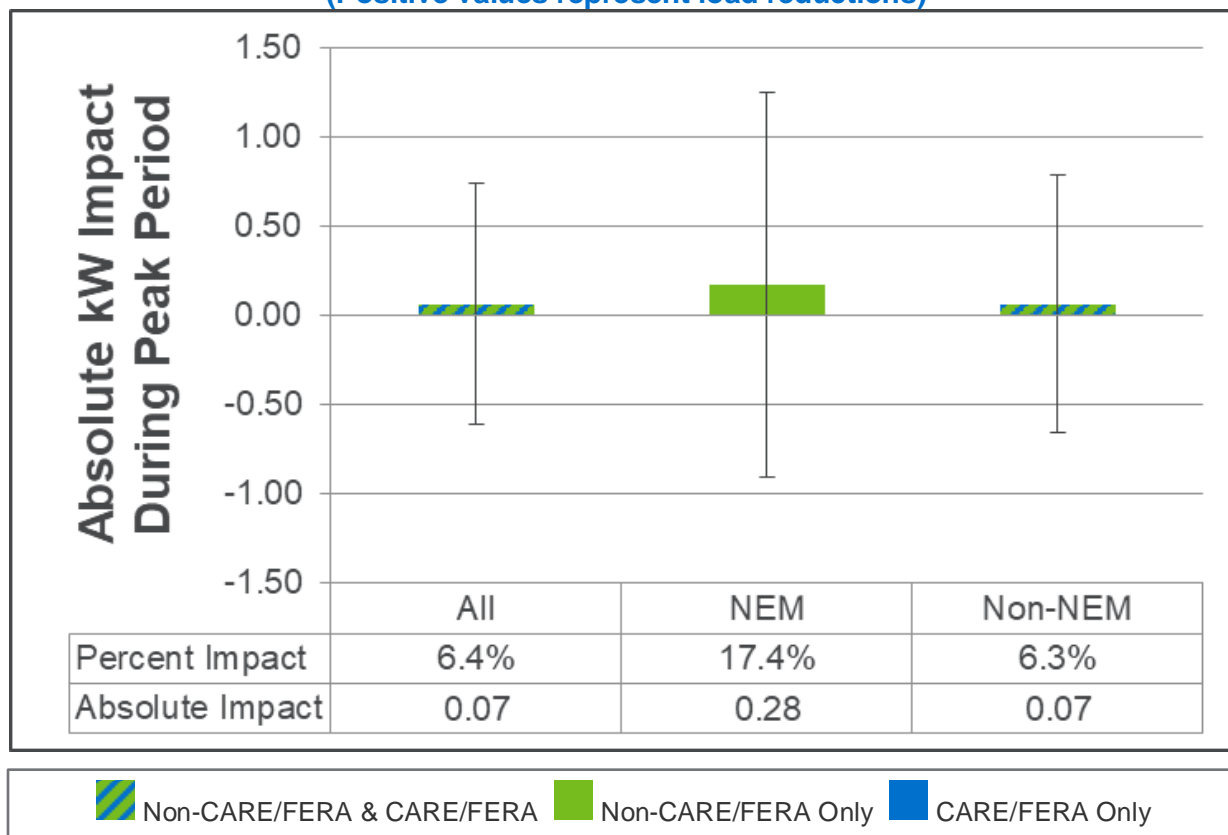
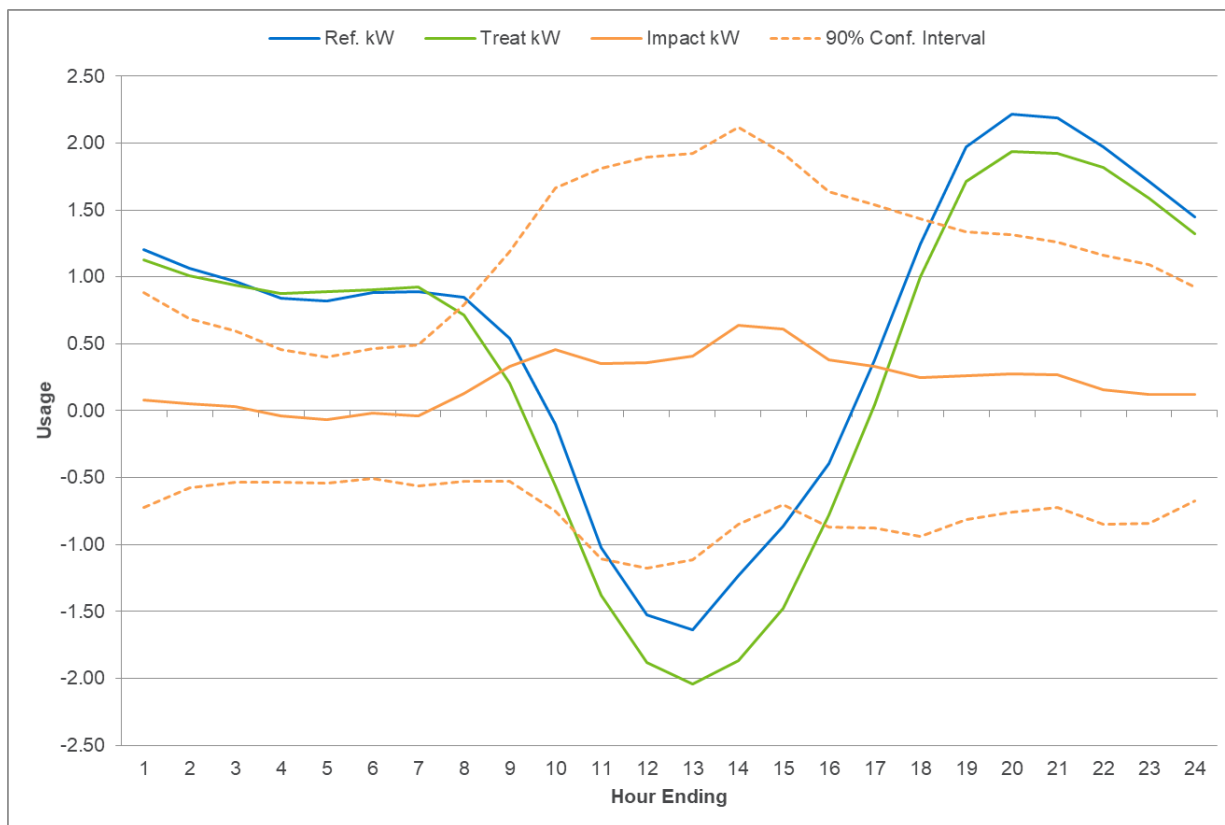


Figure 4-8 shows the daily reference and treatment loads for Rate 2 NEM customers on the average weekday during summer 2020. Treatment load is much lower from hours ending 8 through the end of the day, leading to positive load impacts of 0.28 kW and 0.21 kW during the peak and off-peak periods, respectively.

Figure 4-8: Average Weekday Summer Daily Load Impacts for SDG&E Rate 2 - NEM



4.4 Comparison across Rates

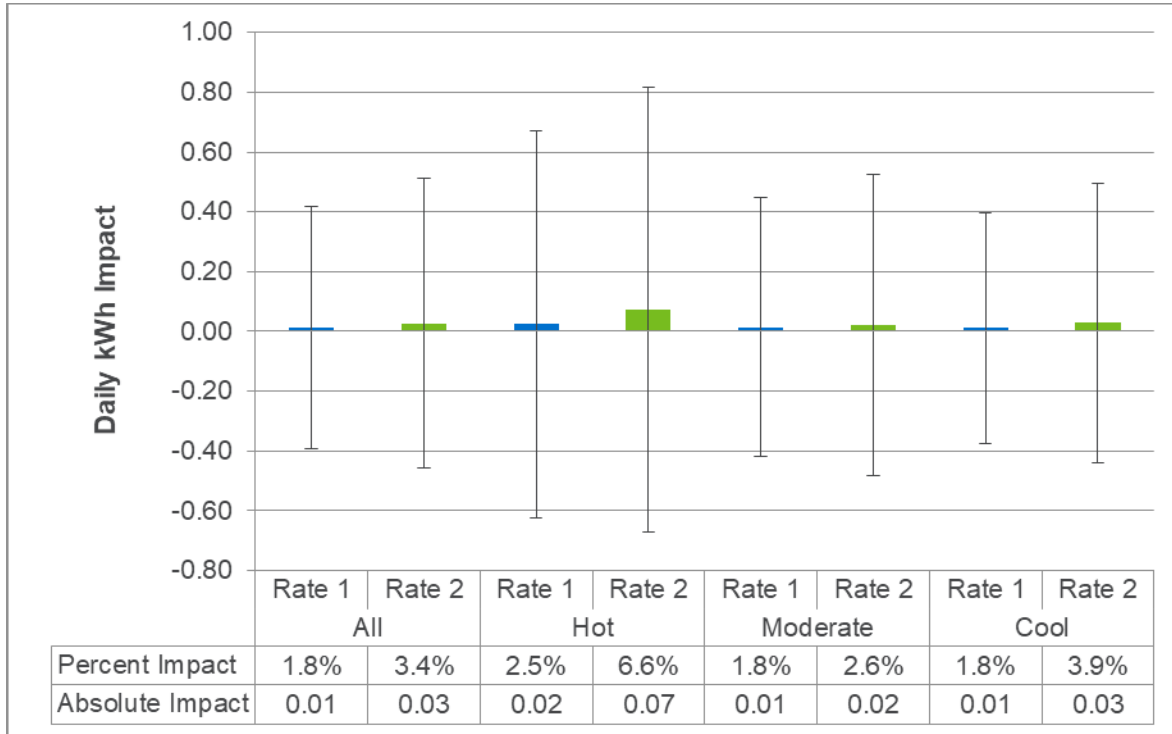
Figure 4-9 shows the average weekday peak-period impact for Rate 1 and Rate 2 in the summer months. The peak period covers the same hours for each rate (4 PM to 9 PM) and the peak-period price is slightly higher for Rate 1 (52 ¢/kWh) compared with Rate 2 (49 ¢/kWh). Impacts are greater for Rate 2 in all climate regions and the service territory, but the differences between rates are not statistically significant.

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



Figure 4-10 shows the average daily kWh impact during the summer period for Rate 1 and Rate 2. Similar to the peak period impacts, daily kWh impacts for Rate 2 are greater than Rate 1 in all climate regions. However, the daily kWh impacts and differences between the rates are not statistically significant.

Figure 4-10: Average Daily kWh Impacts across Rates
(Positive values represent load reductions)



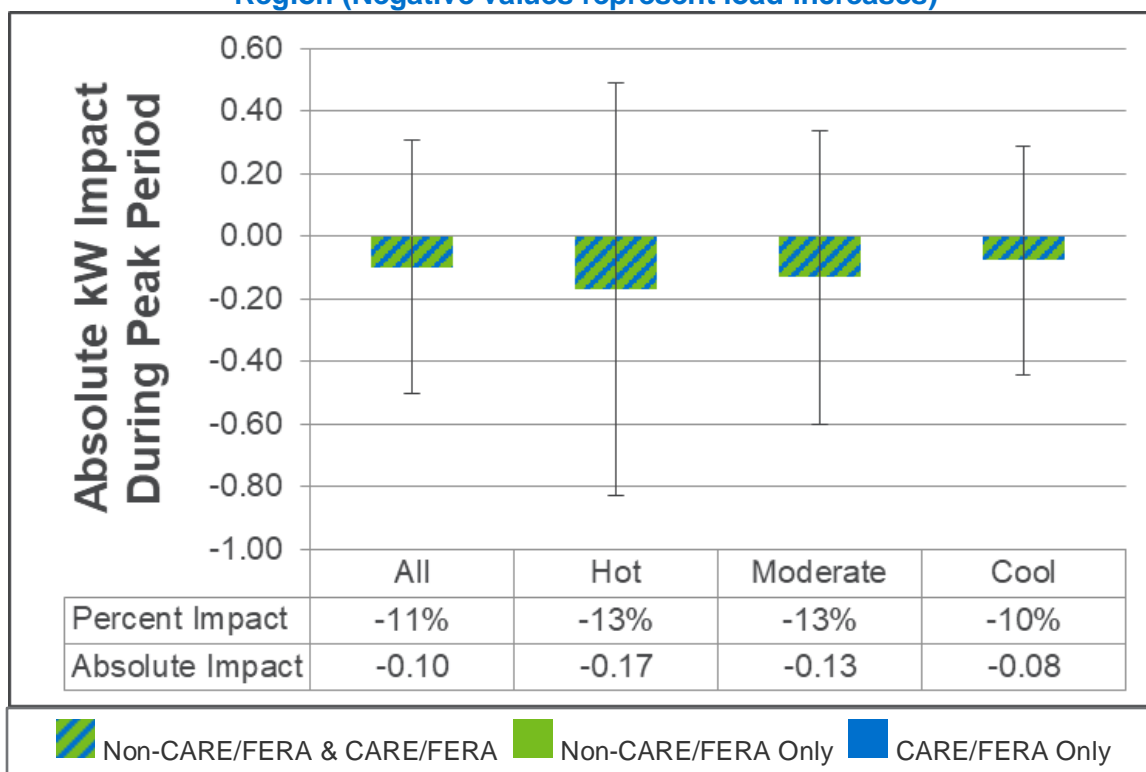
5 COVID-19 Impacts

The impacts in this section represent the effect the COVID-19 pandemic and associated stay-at-home order had on SDG&E D-TOU customers who remained active from April 2019 until the end of October 2020. Using this method, it is possible to compare post-treatment energy usage between 2019 and 2020 for a single consistent group of customers to determine the energy impact of COVID-19. Since there are no residential customers that were isolated from the COVID-19 pandemic, it wasn't possible to create a control group to test for this impact using only 2020 customer load data. As the customers selected included in this analysis were active on the TOU rate for the entire period, the two primary factors influencing changes in load between the two years are weather and the effect from COVID-19. The weather-normalization methodology to isolate the COVID-19 effect is described in more detail in Section 3.2. The results presented in this section were used to correct for the impact of COVID-19 on the ex post reference loads as well as properly forecast the increase to ex ante reference and treatment loads until the expected end of the pandemic's influence on customer load in January 2023.

5.1 Rate 1

Approximately 240,000 customers who remained active on Rate 1 from April 2019 through the end of October 2020 were included in the COVID-19 impacts analysis. Figure 5-1 shows the average peak-period COVID-19 load impact 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. 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. Note that negative values in the figures represent load increases.

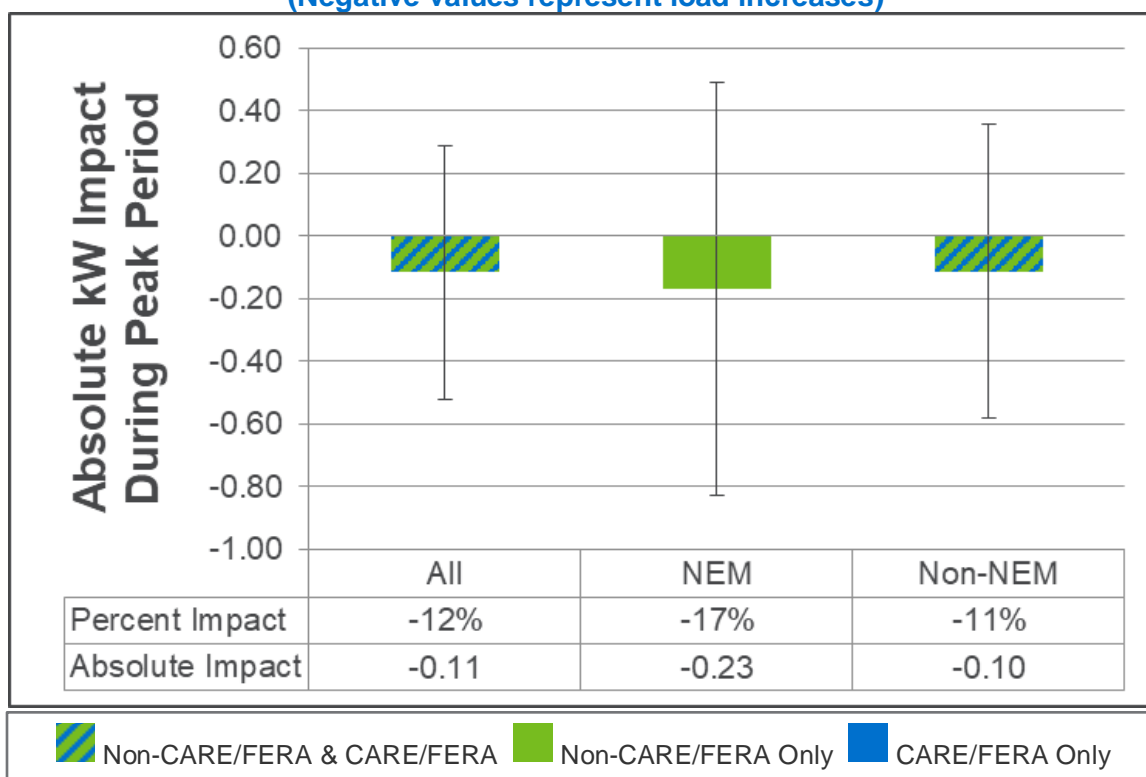
Figure 5-1: Average Peak Period Load COVID-19 Impacts for SDG&E Rate 1 by Climate Region (Negative values represent load increases)



As seen in Figure 5-1, the average peak-period COVID-19 load impacts for the service territory as a whole and for the three climate regions are not statistically significant at the 90% level of confidence. On average, default TOU customers across SDG&E's service territory on Rate 1 increased peak-period electricity use by 11%, or 0.10 kW, across the five hour peak period from 4 PM to 9 PM. Average peak-period load reduction ranges from a high of 13% and 0.17 kW in the hot climate region to a low of about 10% and 0.08 kW in the cool climate region. These results are not statistically significant as the impact from COVID-19 varied substantially across the customer population. At the 90% level of confidence, the estimated impact from COVID-19 during peak period for Rate 1 customers ranged from an increase of approximately 0.50 kW to a decrease of 0.31 kW.

Figure 5-2 presents average summer weekday peak period COVID-19 load impacts for net metered (NEM) customers. These NEM customers showed load increases of 0.23 kW (17%), but the impacts are not statistically significant. Figure 5-2 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.

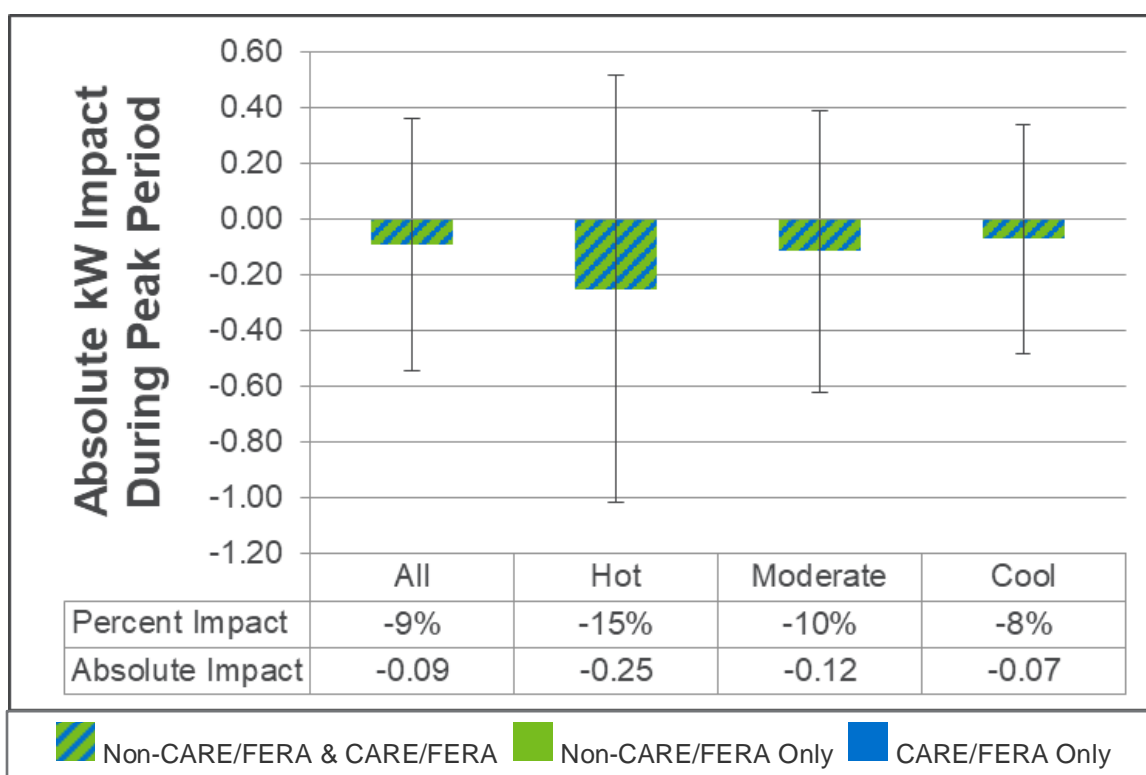
Figure 5-2: Average Peak Period COVID-19 Impacts for SDG&E Rate 1 by NEM Status
(Negative values represent load increases)



5.2 Rate 2

Approximately 15,000 customers who remained active on Rate 2 from April 2019 through the end of October 2020 were included in the COVID-19 impacts analysis. Figure 5-3 shows the average peak-period COVID-19 load impact in absolute terms for Rate 2 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. 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. Note that negative values in the figures represent load increases.

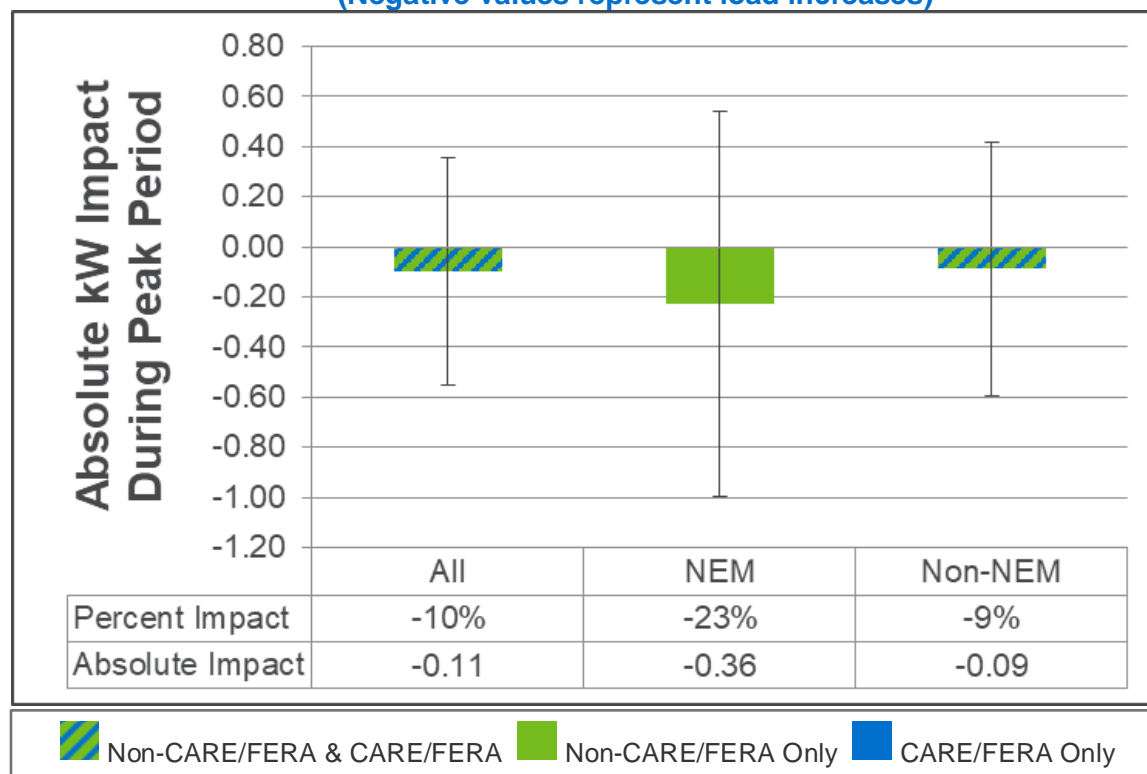
Figure 5-3: Average Peak Period Load COVID-19 Impacts for SDG&E Rate 2 by Climate Region (Negative values represent load increases)



As seen in Figure 5-3, the average peak-period COVID-19 load impacts for the service territory as a whole and for the three climate regions are not statistically significant at the 90% level of confidence. On average, default TOU customers across SDG&E's service territory on Rate 2 increased peak-period electricity use by 9%, or 0.09 kW, across the five hour peak period from 4 PM to 9 PM. Average peak-period load reduction ranges from a high of 15% and 0.25 kW in the hot climate region to a low of about 8% and 0.07 kW in the cool climate region. Similar to Rate 1, these results are not statistically significant as impact from COVID-19 varied substantially across the customer population. At the 90% level of confidence, the estimated impact from COVID-19 during peak period for Rate 2 customers ranged from an increase of approximately 0.54 kW to a decrease of 0.36 kW.

Figure 5-4 presents average summer weekday peak period COVID-19 load impacts for net metered (NEM) customers. These NEM customers showed load increases of 0.36 kW (23%), but the 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 COVID-19 Impacts for SDG&E Rate 2 by NEM Status
(Negative values represent load increases)



6 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.

6.1 Enrollment Forecast

Territory-wide mass defaulting of residential customers throughout 2019 and 2020 led to a large growth in the starting point for the enrollment forecast for the ex ante analysis, beginning at about 837,000 for Rate 1 and 27,000 for Rate 2 in January 2021. Table 6-1 summarizes the enrollment forecast for Rate 1 and Rate 2 for January of each forecast year from 2021 through 2031. Enrollment onto Rate 1 is expected to grow at a rate of 0.36% per year. After 2021, new enrollments are expected to decline for Rate 2, and the population is expected to grow at a rate of only 0.02% per year. 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. As of January 2021, this proportion was approximately 7.6%.

Table 6-1: Enrollment Forecast by Rate and Forecast Year, All Customers (Non-NEM and NEM)

Forecast Year	Rate 1	Rate 2
2021	837,299	27,082
2022	840,318	27,087
2023	843,349	27,092
2024	846,390	27,097
2025	849,442	27,102
2026	852,505	27,107
2027	855,579	27,112
2028	858,664	27,117
2029	861,760	27,121
2030	864,868	27,126
2031	867,986	27,131

6.2 Rate 1

Table 6-2 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 between 0.01 and 0.02 kW in the summer months.

Table 6-2: 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	0.00	57.9	0.00	57.9
	February	0.00	54.9	0.00	54.9
	March	0.00	59.8	0.00	58.0
	April	0.00	60.8	0.00	58.8
	May	0.00	62.7	0.00	63.4
	June	0.01	65.0	0.01	64.6
	July	0.01	69.4	0.01	70.6
	August	0.02	72.0	0.02	73.0
	September	0.02	70.5	0.02	70.5
	October	0.01	65.4	0.01	64.4
	November	0.00	58.0	0.00	61.7
	December	0.01	55.2	0.01	57.7
1-in-10	January	0.00	53.0	0.00	53.0
	February	0.00	53.7	0.00	53.9
	March	0.00	57.9	0.00	58.0
	April	0.00	63.4	0.00	62.9
	May	0.00	65.0	0.00	63.5
	June	0.01	68.5	0.01	68.5
	July	0.01	72.2	0.01	72.2
	August	0.02	74.0	0.02	74.0
	September	0.02	74.9	0.02	74.9
	October	0.01	69.5	0.01	69.5
	November	0.00	63.6	0.00	63.6
	December	0.01	53.2	0.01	54.5

Figure 6-1 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 0.02 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, summer temperatures are warmer under 1-in-10 conditions (versus 1-in-2), leading to greater per-customer load impacts in those months. In the winter months, 1-in-2 weather conditions are comparable to 1-in-10 conditions. In these cases, 1-in-2 impacts are similar to 1-in-10 impacts.

Figure 6-1: Average Weekday Ex Ante Impact Estimates – SDG&E Weather, All Rate 1 Customers (Non-NEM and NEM)

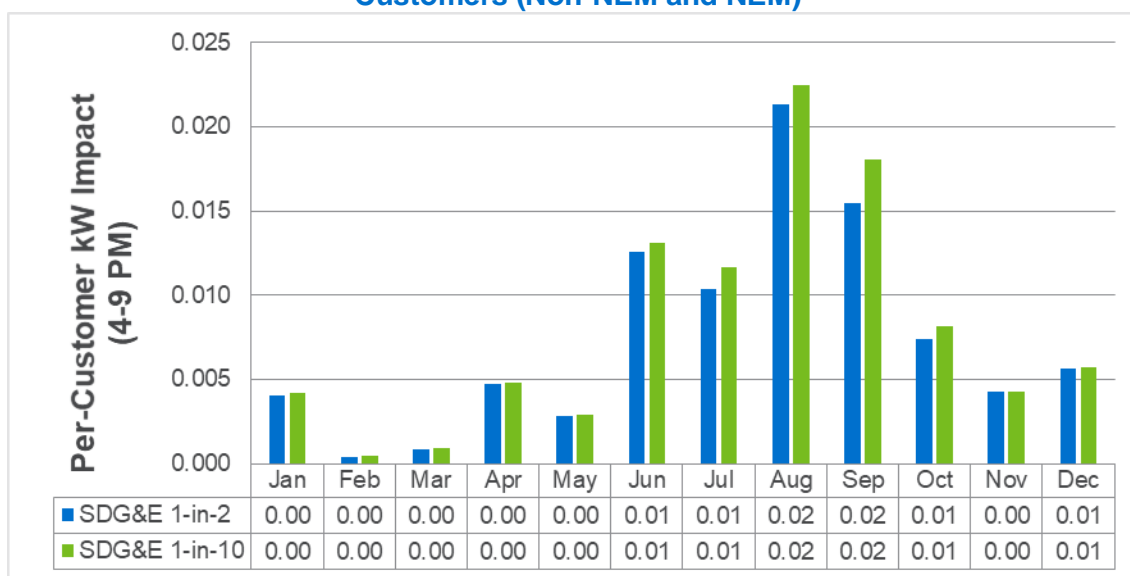


Table 6-3 summarizes the aggregate ex ante load impact estimates for each month and year of the forecast. The impacts presented in this table are in MW. As described previously, impacts are expected to be greatest in the summer months. The largest expected load impact of 19.5 MW occurs in August under 1-in-10 conditions, when the ex ante weather is near the warmest and when enrollment is expected to be highest. Aggregate impacts are expected to be smallest in February, with a forecast of 0.3-0.4 MW in most years.

Table 6-3: 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	2021	3.4	0.3	0.7	4.0	2.4	10.5	8.7	17.9	13.0	6.2	3.6	4.7
	2022	3.4	0.3	0.7	4.0	2.4	10.6	8.7	18.0	13.0	6.2	3.6	4.7
	2023	3.4	0.3	0.7	4.0	2.4	10.6	8.8	18.0	13.1	6.3	3.6	4.8
	2024	3.4	0.3	0.7	4.0	2.4	10.7	8.8	18.1	13.1	6.3	3.6	4.8
	2025	3.5	0.3	0.7	4.0	2.4	10.7	8.8	18.2	13.2	6.3	3.7	4.8
	2026	3.5	0.3	0.7	4.1	2.4	10.7	8.9	18.2	13.2	6.3	3.7	4.8
	2027	3.5	0.3	0.7	4.1	2.4	10.8	8.9	18.3	13.3	6.4	3.7	4.8
	2028	3.5	0.3	0.7	4.1	2.4	10.8	8.9	18.4	13.3	6.4	3.7	4.8
	2029	3.5	0.4	0.7	4.1	2.5	10.8	9.0	18.4	13.4	6.4	3.7	4.9
	2030	3.5	0.4	0.8	4.1	2.5	10.9	9.0	18.5	13.4	6.4	3.7	4.9
	2031	3.5	0.4	0.8	4.1	2.5	10.9	9.0	18.6	13.5	6.4	3.7	4.9
SDG&E 1-in-10	2021	3.5	0.4	0.7	4.0	2.4	11.0	9.8	18.9	15.2	6.8	3.6	4.8
	2022	3.5	0.4	0.8	4.0	2.4	11.0	9.8	18.9	15.2	6.9	3.6	4.8
	2023	3.6	0.4	0.8	4.0	2.4	11.1	9.8	19.0	15.3	6.9	3.6	4.8
	2024	3.6	0.4	0.8	4.0	2.4	11.1	9.9	19.1	15.3	6.9	3.6	4.8
	2025	3.6	0.4	0.8	4.1	2.4	11.1	9.9	19.1	15.4	6.9	3.6	4.9
	2026	3.6	0.4	0.8	4.1	2.4	11.2	9.9	19.2	15.5	7.0	3.6	4.9
	2027	3.6	0.4	0.8	4.1	2.5	11.2	10.0	19.3	15.5	7.0	3.7	4.9
	2028	3.6	0.4	0.8	4.1	2.5	11.3	10.0	19.4	15.6	7.0	3.7	4.9
	2029	3.6	0.4	0.8	4.1	2.5	11.3	10.1	19.4	15.6	7.0	3.7	4.9
	2030	3.7	0.4	0.8	4.1	2.5	11.3	10.1	19.5	15.7	7.1	3.7	4.9
	2031	3.7	0.4	0.8	4.1	2.5	11.4	10.1	19.6	15.7	7.1	3.7	5.0

6.3 Rate 2

Table 6-4 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 6-4: 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	57.8	0.01	57.8
	February	0.00	54.8	0.00	54.8
	March	0.00	59.7	0.00	57.9
	April	0.01	60.6	0.01	58.7
	May	0.01	62.7	0.01	63.3
	June	0.02	64.9	0.02	64.6
	July	0.02	69.5	0.02	70.6
	August	0.02	71.9	0.02	73.0
	September	0.01	70.5	0.01	70.5
	October	0.00	65.3	0.00	64.3
	November	0.01	57.9	0.01	61.5
	December	0.01	55.1	0.01	57.6
1-in-10	January	0.01	52.9	0.01	53.0
	February	0.00	53.7	0.00	53.7
	March	0.00	57.9	0.00	57.9
	April	0.01	63.3	0.01	62.8
	May	0.01	65.0	0.01	63.5
	June	0.02	68.6	0.02	68.6
	July	0.02	72.2	0.02	72.2
	August	0.02	74.1	0.02	74.1
	September	0.02	74.9	0.02	74.9
	October	0.00	69.4	0.00	69.4
	November	0.01	63.5	0.01	63.5
	December	0.01	53.2	0.01	54.4

Figure 6-2 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, resulting in comparable load

Figure 6-2: Average Weekday Ex Ante Impact Estimates – SDG&E Weather, All Rate 2 Customers (Non-NEM and NEM)

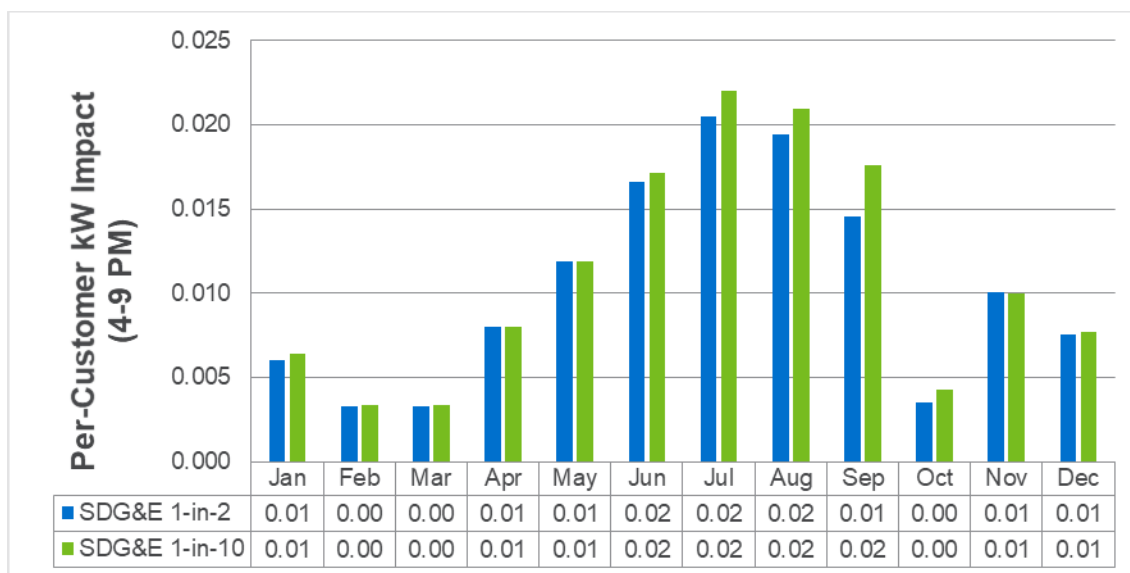


Table 6-5 summarizes the aggregate ex ante load impact estimates for each month and year of the forecast for Rate 2. Again, the impacts presented in this table are in MW, not kW. Like Rate 1, impacts are expected to be greatest in the summer months. The largest impacts are expected in July of both weather years in July (0.6 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 2021 and 2031.

Table 6-5: 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	2021	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.5	0.4	0.1	0.3	0.2
	2022	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.5	0.4	0.1	0.3	0.2
	2023	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.5	0.4	0.1	0.3	0.2
	2024	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.5	0.4	0.1	0.3	0.2
	2025	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.5	0.4	0.1	0.3	0.2
	2026	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.5	0.4	0.1	0.3	0.2
	2027	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.5	0.4	0.1	0.3	0.2
	2028	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.5	0.4	0.1	0.3	0.2
	2029	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.5	0.4	0.1	0.3	0.2
	2030	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.5	0.4	0.1	0.3	0.2
	2031	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.5	0.4	0.1	0.3	0.2
SDG&E 1-in-10	2021	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.6	0.5	0.1	0.3	0.2
	2022	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.6	0.5	0.1	0.3	0.2
	2023	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.6	0.5	0.1	0.3	0.2
	2024	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.6	0.5	0.1	0.3	0.2
	2025	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.6	0.5	0.1	0.3	0.2
	2026	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.6	0.5	0.1	0.3	0.2
	2027	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.6	0.5	0.1	0.3	0.2
	2028	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.6	0.5	0.1	0.3	0.2
	2029	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.6	0.5	0.1	0.3	0.2
	2030	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.6	0.5	0.1	0.3	0.2
	2031	0.2	0.1	0.1	0.2	0.3	0.5	0.6	0.6	0.5	0.1	0.3	0.2

7 Recommendations

Due to the majority of SDG&E's residential customers being on a TOU rate by the beginning of summer 2020, there were not enough customers remaining to establish a control group to estimate ex post load impacts. As an alternative, customers' energy usage prior to being defaulted onto a TOU rate was compared with their energy usage after being defaulted. However, there were limitations with the regression-based approach that did not exist when comparing treatment customers to a control group. The percent and absolute impacts from the 2020 evaluation under the new methodology were similar to the summer 2019 evaluation of newly defaulted customers. However, as discussed in Section 3.1.3, the ex post load impacts were not statistically significant.

Prior evaluations have shown there are statistically significant load impacts attributable to the TOU rates; and the influence of TOU rates on customer load needs to be properly accounted for in utility load forecasting. In the future, Nexant recommends that SDG&E provide ex ante updates only—based on historical ex post analysis from prior evaluations where results were statistically significant, changes in expected customer enrollment, and any changes in the ex ante weather scenarios—and not conduct additional ex post analysis of the D-TOU rate in subsequent program years. Alternatively, the effect of TOU rates on residential customer load could be moved outside of measurement & evaluation and embedded directly into the residential load forecast, and not included in the load impact protocol based evaluations.



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