**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations.	R.12-06-013 (Filed June 21, 2012)

**LOAD IMPACT EVALUATION OF PACIFIC GAS AND
ELECTRIC COMPANY'S RESIDENTIAL DEFAULT
TIME-OF-USE PRICING PILOT**

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Dated: April 1, 2020

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LOAD IMPACT EVALUATION OF PACIFIC GAS AND ELECTRIC COMPANY'S RESIDENTIAL DEFAULT TIME-OF-USE PRICING PILOT

Pursuant to Resolution E-4846, which adopted PG&E Advice letter 4979-E, Pacific Gas and Electric Company (PG&E) submits its Load Impact Evaluation of its Residential Default Time-of-Use Pricing Pilot (Report) for the time period of June 2018 through May 2019. The Report is submitted for filing in R.12-06-013, concurrently with PG&E's April 1, 2020 Load Impact report filing in R.13-09-011. The Report will be served on the service lists for R.12-06-013, R.13-09-011, A.17-01-012, et seq., and R.19-11-009.

Respectfully Submitted,

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Dated: April 1, 2020

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Load Impact Evaluation of Pacific Gas and Electric Company's Residential Default Time-of-Use Pricing Pilot

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Executive Summary

<u>Background</u>

This report documents the load impact evaluation for the first year of Pacific Gas and Electric Company's ("PG&E") pilot residential default time-of-use (TOU) rate, E-TOU-C3. The evaluation covers the time period of June 2018 through May 2019. The evaluation was conducted in two parts: a summer evaluation covering June through September 2018; and a winter evaluation covering October 2018 through May 2019.

The primary goals of the evaluation are the following:

1. Estimate summer and winter load impacts for each segment;
2. Summarize the structural bill impacts; and
3. Summarize pilot opt-out rates.

E-TOU-C3 has two pricing periods: peak and off-peak. The TOU prices vary seasonally, with summer defined as June through September and winter as all other months, while the hours included in the pricing periods are fixed for the year. The peak period is defined as 4 p.m. to 9 p.m. on all days. E-TOU-C3 includes a tiered rate structure in which customers receive a $/kWh credit for usage up to the amount of the tariff-defined baseline quantities that vary geographically by Baseline Territory.

The pilot divided customers into eight segments as follows:

1. Hot climate region, non-CARE customers;
2. Moderate climate region, non-CARE customers;
3. Moderate climate region, CARE customers;
4. Cool climate region, non-CARE customers;
5. Cool climate region, CARE customers;
6. All customers in the Sonoma Clean Power (SCP) CCA;
7. All customers in the MCE CCA; and
8. PG&E's NEM customers.

CARE customers in the hot climate region are excluded from the Default TOU process and are therefore excluded from the pilot. The NEM segment (segment 8) contains all PG&E customers who were NEM customers at the time the pilot was being established. Customers who adopted NEM during the pilot remain in their segment. The two CCA segments (6 and 7) contain customers of all applicable types within the CCA (*i.e.*, CARE and non-CARE as well as NEM).

<u>Methodology</u>

A random encouragement design (RED) methodology is employed to estimate TOU load impacts, in which "treatment" customers are defined as those who met the eligibility criteria and were selected to default onto E-TOU-C3, inclusive of those who opted out and those who chose not to opt out. The "control" population includes customers who also met the eligibility criteria but were not selected to be defaulted onto the rate.

Due to differences between the treatment and control groups, matching was conducted to ensure comparability across the two groups. Load impacts were estimated using the resulting matched control group combined with the treatment customers. A difference-in-differences method was used, which estimates the load impact based on differences in treatment and control-group customer usage during the treatment period, adjusting for any corresponding differences in usage during the pre-treatment period.

Regression models are used to estimate the load impact for all treatment customers, including those who opted out of the TOU rate. The load impact for the customers on the TOU rate (*i.e.*, the treatment effect on the treated customers) is then estimated by dividing this estimated RED load impact by the percentage of customers accepting the treatment (*i.e.*, served on a TOU rate). The latter load impact is reported in the study.

Load Impacts

Table ES.1 summarizes the average reference load and load impact by season, day type, and TOU pricing period. The estimates reflect all pilot customer segments, weighted to account for the oversampling of some segments due to customer exclusions in Phase I.[1]

Table ES.1: Seasonal Average Hourly Load Impacts for PG&E, Weighted Across the Analysis Segments

Season	Day Type	Pricing Period	Reference (kWh/hr)	Impact (kWh/hr)	% Impact
Summer	Non-holiday weekday	Peak	0.944	0.038	4.0%
		Off-peak	0.585	-0.003	-0.5%
		All Hours	0.660	0.005	0.8%
	Weekend/Holiday	Peak	0.981	0.034	3.4%
		Off-peak	0.627	-0.003	-0.4%
		All Hours	0.701	0.005	0.7%
Winter	Non-holiday weekday	Peak	0.793	0.007	0.9%
		Off-peak	0.553	-0.006	-1.1%
		All Hours	0.603	-0.003	-0.5%
	Weekend/Holiday	Peak	0.821	0.003	0.3%
		Off-peak	0.597	-0.006	-1.0%
		All Hours	0.644	-0.004	-0.7%

Positive impact values = load reductions
Negative impact values = load increases
Shaded cell indicates that the estimated load impact is not statistically significant

The estimates reflect the following:

- Peak-period load impacts tend to be higher in summer than winter. Across all segments on non-holiday weekdays, the summer peak-period impact is 0.038 kWh/hour (4.0 percent) vs. 0.007 kWh/hour (0.9 percent) in winter. This could reflect customer response to the higher peak to off-peak price differential in summer.

[1] Particularly the exclusions of customers in non-participating CCAs, planned and upcoming CCAs, and exclusions by billing cycle to meet operational testing requirements, which resulted in PG&E's eligible pilot population being disproportionately hot climate region customers.

- Within season, weekend/holiday reference loads tend to be higher than those of non-holiday weekdays, but the load impacts are somewhat lower in level and percentage terms. For example, the summer peak-period reference load is 0.944 kWh/hour on non-holiday weekdays and 0.981 on weekends/holidays. In contrast, the load impact is 0.038 kWh/hour (4.0 percent of reference load) on non-holiday weekdays but 0.034 kWh/hour (3.4 percent of reference load) on weekends/holidays. Because prices do not differ by day of week, this difference is likely due to differences in customer demand and/or preferences across day types.
- The estimates reflect some overall conservation during the summer, but an overall load increase during the winter. The combined effect resulted in annual usage changes that were not statistically significantly different from zero.
- There is evidence for load shifting, as decreases in peak-period usage are accompanied by increase in off-peak period usage. For example, summer off-peak usage on non-holiday weekdays increased by 0.5 percent. Note that this result is largely driven by non-CARE customers in the hot climate region.

<u>Structural Bill Impacts</u>
PG&E calculated customer bills on E-TOU-C3 and E-1 using pre-pilot usage data, when all customers were served on E-1 (the standard tiered rate). This information allowed PG&E to categorize each customer's "instant" bill impact if they were to transition from E-1 to E-TOU-C3. That is, this instant or structural bill impact represents the change in the customer's bill prior to the customer taking any action to respond to the TOU price signals.

Each customer's structural bill impact is categorized as follows:

- Neutral = annual bill impact less than $10 (positive or negative)
- Benefiter = annual savings on E-TOU-C3 of $10 or more
- Non-benefiter = annual bill increase in E-TOU-C3 of $10 or more

The analysis of structural bill impacts revealed the following:

- Most non-CARE customers are structural non-benefiters while most CARE customers are structural benefiters.
- The share of non-benefiters is higher in hotter climate regions. For non-CARE customers, the non-benefiter percentage is 70.5 percent in the hot climate region, 48.5 percent in the moderate climate region, and 41.2 percent in the cool climate region.
- Most NEM customers are non-benefiters (81.5 percent).
- While a higher share of customers is structural non-benefiters, the structural bill decrease for benefiters tends to be larger than the structural bill increase for non-benefiters. For example, for non-CARE customers in the hot climate region, the average structural bill decrease for benefiters is $242 per year, while the average structural bill increase for non-benefiters is $66 per year.

Customer Opt-outs

Pilot customers who are defaulted onto E-TOU-C3 may elect to take service on one of PG&E's other rates, including the E-1 tiered rate and two TOU rates (E-TOU-A and E-TOU-B). The analysis presents the E-TOU-C3 opt-out rates at the beginning and end of the first year (June 2018 through May 2019), by segment. In addition, we show the participation rates in the other rate options.

Key findings regarding customer opt-out behavior include:

- Most of the opt-outs to the standard tiered E-1 rate occurred prior to the analysis period.
- Some of the customers who opted out of the Default E-TOU-C3 selected a voluntary TOU rate (E-TOU-A or E-TOU-B) rather than E-1. This accounts for more than 10 percent of the customers in some of the segments.
- Opt-outs to E-1 tend to be higher as the climate region becomes hotter (hot > moderate > cool).
- Opt-outs to E-1 tend to be higher for non-CARE customer segments than CARE segments.
- The opt-out behavior in the two CCAs approximates that of the moderate climate region.

1. Introduction and Purpose of the Study

This report documents the load impact evaluation for the first year of Pacific Gas and Electric Company's ("PG&E") pilot residential default time-of-use (TOU) rate, E-TOU-C3. The evaluation covers the time period of June 2018 through May 2019. The evaluation was conducted in two parts: a summer evaluation covering June through September 2018; and a winter evaluation covering October 2018 through May 2019.

The primary goals of the evaluation are the following:

1. Estimate summer and winter load impacts for each segment;
2. Summarize the structural bill impacts;[2] and
3. Summarize pilot opt-out rates.

Clarifying the second goal, the structural bill impact is defined as a customer's bill change when their tiered rate (E-1) usage is billed at E-TOU-C3 rates. That is, it represents the customer's bill change prior to any response to the TOU price signals.

The third goal summarizes the extent to which eligible customers accept the default TOU rate, voluntarily adopt a different TOU rate, or remain or revert to the standard tiered rate (E-1).

The report is organized as follows. Section 2 contains descriptions of the TOU rate and pilot; Section 3 describes the methods used to estimate summer and winter load impacts; Section 4 presents the estimated load impacts by season; Section 5 contains a summary of the structural bill impacts; Section 6 contains a summary of pilot opt-outs; and Section 7 summarizes the key findings from the pilot.

2. Description of the Default Time-of-Use Rate and Pilot

2.1 Pilot Background

On July 3, 2015, the CPUC issued D.15-07-001, *CPUC Decision on Residential Rate Reform*, setting the course for residential rate reform, and for each of California's major investor-owned utilities (IOU)—PG&E, San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (the IOUs)—to implement residential Default time-of-use rates. Per the requirements of this Decision, the first phase of this transition Default Pilot (now known as TOU Transition Phase I) has been limited to a subset of the total eligible population, with the objective of understanding the operational and customer impacts of defaulting customers to a TOU rate in order to prepare for the full rollout of default TOU. A sample of 160,525 customers was selected from the total eligible population after applying exclusions for Phase I of Transition. To test operational readiness, only accounts with a billing cycle falling in the second half of the month were chosen for the transition to the Default rate.

[2] The structural bill impact is defined as a customer's bill change when their E-1 usage is billed at E-TOU-C3 rates. That is, it represents the customer's bill change prior to any response to the TOU price signals.

Between January 2018 and April 2018, PG&E completed pre-default communications notifying the 160,525 accounts selected for the transition through multiple channels. At the end of this period, the 113,991 accounts that had not declined the transition or become ineligible were transitioned onto the new rate during their next billing cycle. Customers selected for Phase I of the transition have the option to decline the transition and move to their old rate plan or choose a new TOU rate at any time. Section 6 describes the participation rates in the available options for the Default pilot customers over the course of the analysis year. Customers not selected to be defaulted onto E-TOU-C3 had the option to voluntarily join it beginning in April 2018, but voluntary adopters of E-TOU-C3 are not included in this study.

2.2 Rate Descriptions

E-TOU-C3 has two pricing periods: peak and off-peak. The TOU prices vary seasonally, with summer defined as June through September and winter as all other months, while the hours included in the pricing periods are fixed for the year. The peak period is defined as 4 p.m. to 9 p.m. on all days. E-TOU-C3 includes a tiered rate structure in which customers receive a $/kWh credit for usage up to the amount of the tariff-defined baseline quantities that vary geographically by Baseline Territory.

Figure 2.1 illustrates the total energy rates by season and pricing period.[3] The rates do not reflect the baseline credit of $0.08730 / kWh, the delivery minimum bill amount of $0.32854 per meter per day, or the semi-annual California Climate Credit of $39.42 per household. Note that the summer peak to off-peak price differential is somewhat larger than that of the winter.

[3] The rates are: summer peak = $0.38088/kWh; summer off-peak = $0.31744/kWh; winter peak = $0.29379/kWh; winter off-peak = $0.27646/kWh.

Figure 2.1: Total E-TOU-C3 Rate by Season and Pricing Period

In contrast, the tiered E-1 rate that has served as PG&E's default residential rate has the following rates: $0.22376/kWh for baseline usage; $0.28159/kWh for 101% to 400% of baseline usage; and $0.49334/kWh for high usage over 400% of baseline. The E-1 rate is not seasonally differentiated.

Two optional TOU rates were available to customers: E-TOU-A and E-TOU-B. In addition to differences in the TOU rates by pricing period, these TOU rates differ from E-TOU-C3 in the following ways:

- E-TOU-A has a peak period from 3 p.m. to 8 p.m. rather than 4 p.m. to 9 p.m.;
- Both rates apply off-peak prices to **all weekend and holiday hours** (whereas E-TOU-C3's peak prices are applicable on all days of the year; and
- E-TOU-B does not include a baseline credit.

2.3 Pilot Segments

The pilot divided customers into eight segments. Differentiation exists by climate region; California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) Program status, hereafter together referred to as "CARE"; net energy metering (NEM) status; and community choice aggregation (CCA) locations. The eight segments are numbered and defined as follows:

1. Hot climate region, non-CARE customers;
2. Moderate climate region, non-CARE customers;
3. Moderate climate region, CARE customers;
4. Cool climate region, non-CARE customers;
5. Cool climate region, CARE customers;
6. All customers in the Sonoma Clean Power (SCP) CCA;
7. All customers in the MCE CCA; and
8. PG&E's NEM customers.

CARE customers in the hot climate region are excluded from the Default TOU process and are therefore excluded from the pilot. The NEM segment (segment 8) contains all PG&E customers who were NEM customers at the time the pilot was being established. Customers who adopted NEM during the pilot remain in their segment. The two CCA segments (6 and 7) contain customers of all applicable types within the CCA (*i.e.*, CARE and non-CARE as well as NEM).

PG&E applies weights when combining results across the segments. The weighting accounts for the oversampling of some segments due to customer exclusions in Phase I; particularly the exclusions of customers in non-participating CCAs, planned and upcoming CCAs, and exclusions by billing cycle to meet operational testing requirements, which resulted in PG&E's eligible pilot population being disproportionately hot climate region customers.

3. Methodology

3.1 Load Impact Estimation

A random encouragement design (RED) methodology is employed to estimate TOU load impacts, in which "treatment" customers are defined as those who met the eligibility criteria and were selected to default onto E-TOU-C3, inclusive of those who opted out and those who chose not to opt out. The "control" population includes customers who also met the eligibility criteria but were not selected to be defaulted onto the rate.[4]

Eligibility criteria included having 12 months of interval data, being enrolled in the standard tiered E-1 rate, not being a part of a future CCA, not being CARE enrolled in PG&E's hot climate region, and not being enrolled in Medical Baseline. A full list of eligibility criteria can be found in PG&E's Default Pilot advice letter filing, Advice 4979-E.[5]

The regression models estimate the load impact for all treatment customers, including those who opted out of the TOU rate. The load impact for the customers on the TOU rate (*i.e.*, the treatment effect on the treated customers) is then estimated by dividing this estimated RED load impact by the percentage of customers accepting the treatment (*i.e.*, served on a TOU rate).

To test PG&E's operational readiness for Default TOU, PG&E simulated default conditions by limiting treatment customers to those whose billing cycle fell within a two-week period. Because not enough eligible control candidates fell within this same billing cycle, customers who fell in other billing cycles were included in the control-group customer pool. While a customers' billing cycle assignment is largely random, there were some differences in the geographic distribution of customers across billing

[4] Additional details on the pilot design can be found in Nexant, "Time-of-Use Pricing Default Pilot Plan: Final Report," November 20, 2016.
[5] Customers needed to meet all of these eligibility criteria to be selected in either the treatment or control pools.

cycles. To control for this, the control group was refined through matching to achieve geographic balance between treatment and control groups.

Control group selection

Treatment customers were matched to control-group customers based on their location and three 24-hour load profiles. The load profiles reflect usage in 2017, before customers were placed on the TOU rate (*i.e.*, all treatment and control-group customers were on the standard E-1 rate) and thus not reflecting a treatment effect. For matching purposes, each segment was further divided into two groups according to location (*e.g.*, the northern part of the climate region vs. the southern part). Customers were matched within sub-segment, which ensures a perfect match on the characteristics that define the sub-segment (*e.g.*, CARE status or climate region). Separate matching was conducted for the summer and winter evaluations. Within each season, the three load profiles were defined as follows:

- Extreme (hot or cold) weekday
- Average weekday
- All weekends / holidays

"Extreme" dates are defined as the top 10% of dates sorted by average daily temperature (*i.e.*, hottest days in the summer and coldest days in the winter). "Average" weekdays are the middle 50% of the temperature distribution. Half of these days were randomly selected for inclusion in the matching profile, with the remaining half withheld for use in potential validation exercises. For matching purposes, summer is defined as June 16 through September 15. The week of July 4th was excluded from the matching profiles to prevent odd vacation-related usage patterns from affecting the match quality. Winter is defined as December 1 through February 28, excluding dates from December 23 through January 6 to account for the effect of extended holidays on customer usage.

Each treatment customer is matched to a single control-group customer in each season using the Euclidean distance methodology. Under this method, the "distance" between the treatment customer and each eligible control-group customer is calculated over the three 24-hour load profiles.[6] For each treatment customer, the eligible control-group customer with the smallest distance (within sub-segment) is selected as the match.

Once the matched control-group customers are selected, we use regression analysis to compare treatment and control group loads in the treatment period, while controlling for differences in the pre-treatment period (*i.e.*, difference-in-differences), as described below. Appendix B contains a summary of the match quality for each season and segment.

[6] The Euclidean distance combines the 72 hourly load differences for the three load profiles into a single value equal to the square root of the sum of squared differences between the treatment and eligible control-group customer load values.

Load impact estimation

The TOU load impacts are estimated using a difference-in-differences methodology, which essentially compares treatment and control-group customer usage during the treatment period (*e.g.*, June through September 2018 for the summer model), adjusting for the difference in the two group's usage during the pre-treatment period (*e.g.*, June through September 2017 for the summer model). The models include weather variables to account for any mismatch in weather for the treatment and control-group customers. In the summer model, the weather variable is the average temperature at the customer's nearest weather station during the first 17 hours of the day, called "Mean17". The winter model replaces Mean17 with cooling and heating degree days variables.[7] The model also includes fixed customer effects, which account for any customer characteristics that do not change over time; and fixed date effects, which account for any date-specific factors that are assumed to be constant across customers in the model.

Separate models were estimated by segment, weekdays vs. weekends/holidays, and hour. The estimated summer models are of the following form:[8]

$$kW_{c,d} = \alpha + \beta_{TOU} \times (TOU_c \times DPost_d) + \beta_{Mean17} \times Mean17_{c,d} + C_c + D_d + \varepsilon_{c,d}$$

The variables and coefficients in the equation are described in Table 3.1:

[7] Cooling degree days (CDD) = MAX(Average Temperature – 65, 0), where the Average Temperature is calculated as the average of the maximum and minimum temperature for the day. Similarly, heating degree days (HDD) = MAX(65 – Average Temperature, 0).

[8] Note that the customer and date fixed effects prevent the need for us to include stand-alone TOU_c and $DPost_d$ variables. The former is perfectly collinear with the customer's fixed effect and the latter is perfectly collinear with a combination of date fixed effects.

Table 3.1: Regression Model Variable and Coefficient Definitions

Symbol	Description
$kW_{c,d}$	Load in a particular hour for customer *c* on day *d*
TOU_c	Variable indicating whether customer *c* was offered the TOU rate (1) or is a control-group (0) customer
$DPost_d$	Variable indicating that day *d* is in treatment period (post TOU implementation), when E-TOU-C3 was in effect
α	Estimated constant coefficient
β_{TOU}	RED estimate of TOU load impact
β_{Mean17}	Estimate of the effect of temperature on customer usage
$Mean17_{c,d}$	Average temperature during the first 17 hours of day *d* at customer *c*'s nearest weather station
C_c	Customer fixed effects
D_d	Date fixed effects
$\varepsilon_{c,d}$	Error term

The winter model replaces the Mean17 variable with CDD and HDD variables.[9]

In the RED design, the load impact estimate (β_{TOU}) reflects the load change for **all** customers who were offered participation in the pilot program. This is referred to as the intention-to-treat (ITT) effect. In order to estimate the load impact for the customers who accepted the treatment (*i.e.*, faced a TOU rate in the summer of 2018), we adjust the β_{TOU} estimate by dividing by the percentage of the treatment customers on a TOU rate during the treatment period. For example, if 70 percent of the customers who were defaulted onto the TOU rate are served on a TOU rate during the summer of 2018, the summer load impact for the customers on the TOU rate is estimated as β_{TOU} / 0.70.[10]

Note that some treatment customers adopted a voluntary TOU rate (E-TOU-A or E-TOU-B) rather than the Default pilot TOU rate (E-TOU-C3). In our analysis, we include these customers in the percentage of customers accepting the treatment, as they are facing TOU prices in the treatment year. Our assumption is that their decision to join another TOU rate and their associated load impacts were influenced by the default onto the new TOU rate. This assumption is supported by the fact that participating in E-TOU-A and E-TOU-B was much higher for treatment customers relative to control-group customers. For example, only 1.4 percent of control-group customers were on one of

[9] Separate season-specific models were also estimated for the average peak hour, average off-peak hour, and total daily usage. These models allow us to obtain correct standard errors associated with the load impact across those time periods.

[10] The RED analysis method was specified in Nexant's "Time-of-Use Pricing Default Pilot Plan" from November 30, 2016 (pages 18-19).

those voluntary TOU rates during the summer of 2018, whereas 8.2 percent of treatment-group customers were.[11]

3.2 Structural Bill Impacts

PG&E calculated customer bills on E-TOU-C3, E-1, E-TOU-A, and E-TOU-B using pre-pilot usage data, when all customers were served on E-1 (the standard tiered rate). This information allowed PG&E to identify each customer's best rate and to categorize each customer's "instant" bill impact if they were to transition from E-1 to E-TOU-C3. That is, this instant or structural bill impact represents the change in the customer's bill prior to the customer taking any action to respond to the TOU price signals. It is calculated as the difference in the bill when the customer's pre-treatment usage is billed at E-TOU-C3 rates and E-1 rates.

Each customer's structural bill impact is categorized as follows:

- Neutral = annual bill impact less than $10 (positive or negative)
- Benefiter = annual savings on E-TOU-C3 of $10 or more
- Non-benefiter = annual bill increase in E-TOU-C3 of $10 or more

Section 5 contains a summary of the share of customers in each category by segment as well as the average bill impact for benefiters and non-benefiters in each segment.

4. Load Impact Estimates

This section presents the estimated default pilot load impacts by season, segment, and day type. Note that the estimated load impacts include behavior of all defaulted customers. While most of the customers took service on E-TOU-C3, some treatment customers voluntarily switched to E-TOU-A, E-TOU-B, or E-1.[12] Figure 6.4 in Section 6 shows the end-of-year shares of treatment customers by rate, including the share that had terminated service with PG&E by that time. Appendix A is an Excel-based table generator that includes all hourly load impacts and associated results. This section summarizes the key outcomes.

4.1 Summer Load Impacts

Table 4.1 summarizes the average summer load impact by day type and TOU pricing period. The estimates are averaged across the eight pilot segments, weighted to reflect the PG&E system. Peak-period load impacts are higher on non-holiday weekdays vs. weekends and holidays (0.038 vs. 0.034 kWh/hour). The estimates show a small increase in average usage during the off-peak period of 0.003 kWh/hour, but there is a net conservation effect across all hours of 0.8 percent on non-holiday weekdays and 0.7

[11] These shares are calculated by averaging across the summer 2018 days and using the segment weights to combine the participation rates across segments.

[12] Where peak-period load impacts are summarized, we use the E-TOU-C3 definition of 4:00 to 9:00 p.m., as this corresponds to the peak period faced by the majority of the TOU customer and the Resource Adequacy window. Hour-specific load impact estimates are available in Appendix A.

percent on weekends and holidays. All estimated load impacts contained in the table are statistically significantly different from zero.

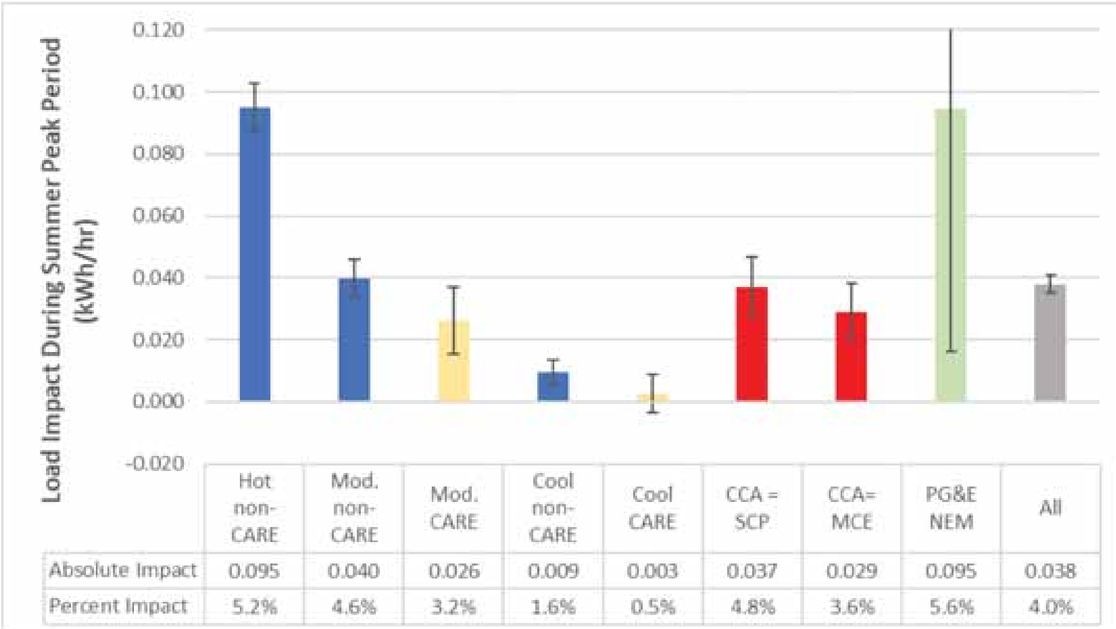
Table 4.1: Summer Average Hourly Load Impacts for PG&E, Weighted Across the Analysis Segments

Day Type	Pricing Period	Reference (kWh/hr)	Impact (kWh/hr)	% Impact
Non-holiday weekday	Peak	0.944	0.038	4.0%
	Off-peak	0.585	-0.003	-0.5%
	All Hours	0.660	0.005	0.8%
Weekend/Holiday	Peak	0.981	0.034	3.4%
	Off-peak	0.627	-0.003	-0.4%
	All Hours	0.701	0.005	0.7%

Positive impact values = load reductions
Negative impact values = load increases
Shaded cell indicates that the estimated load impact is not statistically significant

Figure 4.1 shows the summer peak-period load impacts by segment. The bars are color coded, with blue indicating non-CARE customers, gold representing CARE customers, red indicating CCA customers, green indicating NEM customers, and gray representing the PG&E system average. Comparing the five leftmost bars shows that load impacts tend to be higher in hotter climate regions and for non-CARE customers. While the estimated impact for NEM customers is high, the error band reflects considerable uncertainty about the estimate (a recurring theme for that segment). NEM segment customers only accounted for approximately 1 percent of treatment customers and the low sample size contributes to the uncertainty in their estimates relative to other segments. Thus the results for this segment should be interpreted with some caution.

Figure 4.1: Summer Average Peak-Period Load Impact by Segment, Non-holiday Weekdays



Tables 4.2 and 4.3 expand upon the information shown in Figure 4.1, showing the estimated impacts for the off-peak period, the peak period, and all hours. Table 4.2 contains results for summer non-holiday weekdays while Table 4.3 contains results for summer weekends and holidays. Gray shading indicates estimated load impacts that are not statistically significantly different from zero. The pattern of statistical significance is similar in the two tables: most of the off-peak load impacts are not statistically significant; some of the all-hours estimates are not statistically significant; and most of the peak-period load impacts are statistically significant.

The tables show average reference loads in addition to the level and percentage load impacts. The magnitude of the reference loads conforms to our expectations, with the highest levels in the hot climate region and lowest levels in the cool climate region.

Peak-period reference loads tend to be higher on weekends/holidays, while the associated estimated load impacts are somewhat lower (in level and percentage terms) relative to non-holiday weekdays.

Table 4.2: Average Load Impacts by TOU Pricing Period, Summer Non-holiday Weekdays

Segment	Off-peak			Peak			All Hours		
	Ref.	Impact	% Impact	Ref.	Impact	% Impact	Ref.	Impact	% Impact
Hot non-CARE	0.942	-0.013	-1.3%	1.827	0.095	5.2%	1.126	0.010	0.9%
Mod. non-CARE	0.556	-0.003	-0.5%	0.869	0.040	4.6%	0.621	0.006	1.0%
Mod. CARE	0.525	0.001	0.2%	0.811	0.026	3.2%	0.584	0.006	1.1%
Cool non-CARE	0.451	0.002	0.4%	0.592	0.009	1.6%	0.480	0.003	0.7%
Cool CARE	0.414	-0.002	-0.4%	0.570	0.003	0.5%	0.447	-0.001	-0.2%
CCA = SCP	0.513	0.003	0.6%	0.773	0.037	4.8%	0.567	0.010	1.8%
CCA= MCE	0.534	-0.006	-1.1%	0.815	0.029	3.6%	0.593	0.001	0.2%
PG&E NEM	0.189	0.010	5.1%	1.674	0.095	5.6%	0.499	0.027	5.5%
All	**0.585**	**-0.003**	**-0.5%**	**0.944**	**0.038**	**4.0%**	**0.660**	**0.005**	**0.8%**

Positive impact values = load reductions
Negative impact values = load increases
Shaded cell indicates that the estimated load impact is not statistically significant

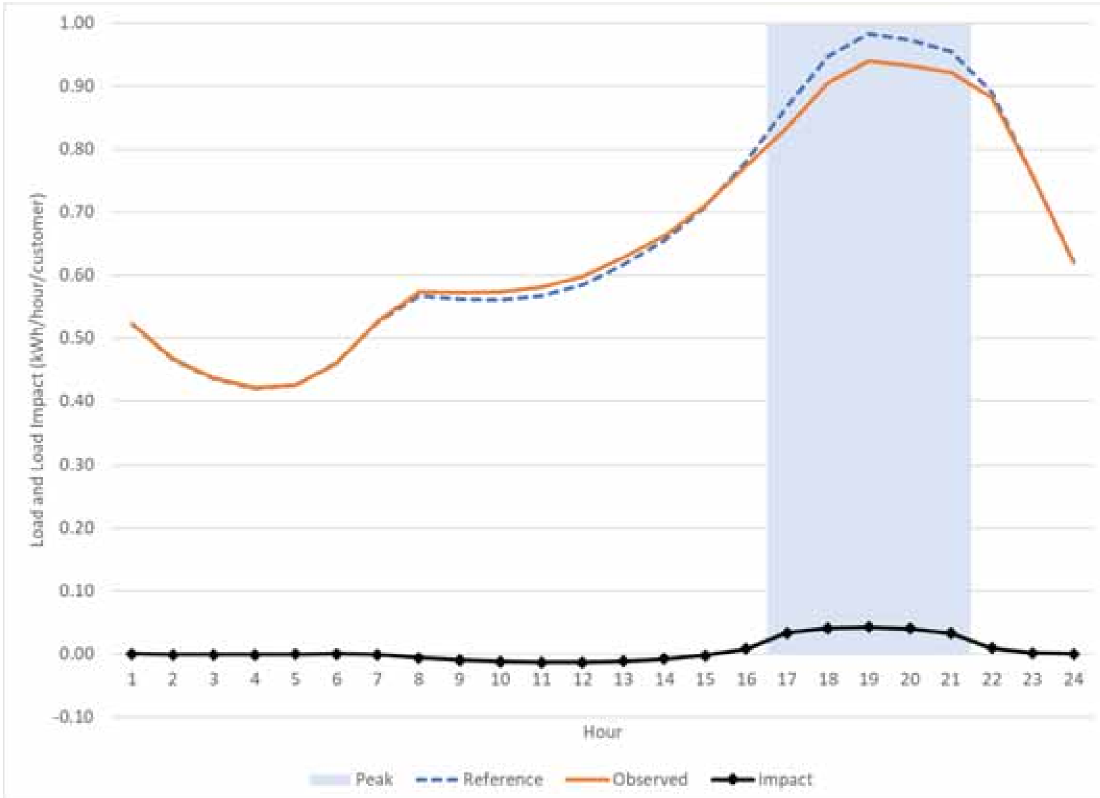
Table 4.3: Average Load Impacts by TOU Pricing Period, Summer Weekends/Holidays

Segment	Off-peak			Peak			All Hours		
	Ref.	Impact	% Impact	Ref.	Impact	% Impact	Ref.	Impact	% Impact
Hot non-CARE	1.010	-0.012	-1.1%	1.874	0.081	4.3%	1.190	0.008	0.6%
Mod. non-CARE	0.604	-0.003	-0.4%	0.920	0.035	3.8%	0.670	0.005	0.8%
Mod. CARE	0.559	0.002	0.3%	0.826	0.024	2.9%	0.615	0.006	1.0%
Cool non-CARE	0.473	0.002	0.4%	0.616	0.012	2.0%	0.503	0.004	0.8%
Cool CARE	0.432	-0.002	-0.5%	0.560	0.000	0.0%	0.459	-0.002	-0.4%
CCA = SCP	0.556	0.005	0.9%	0.809	0.030	3.7%	0.608	0.010	1.7%
CCA= MCE	0.572	-0.005	-0.9%	0.864	0.026	3.0%	0.633	0.001	0.2%
PG&E NEM	0.293	0.034	11.7%	1.779	0.163	9.2%	0.602	0.061	10.1%
All	**0.627**	**-0.003**	**-0.4%**	**0.981**	**0.034**	**3.4%**	**0.701**	**0.005**	**0.7%**

Positive impact values = load reductions
Negative impact values = load increases
Shaded cell indicates that the estimated load impact is not statistically significant

Figure 4.2 shows the average hourly reference loads, observed loads, and load impacts across all segments for summer non-holiday weekdays. The peak-period hours are highlighted in blue. The blue dashed line represents the reference load (the estimate of the load that would have occurred under the E-1 tiered rate), the solid orange line represents the observed load, and the black line with diamond markers is the estimated load impact. The figure clearly shows the peak-period load reductions as well as the more modest load increases in off-peak usage earlier in the day. Overnight usage is largely unaffected by the TOU rate.

Figure 4.2: Summer Non-holiday Weekday Hourly Load and Load Impact, All Segments



4.2 Winter Load Impacts

Table 4.4 summarizes the average winter load impacts by day type and TOU pricing period. The estimates are averaged across the eight pilot segments, weighted to reflect the PG&E system. Peak-period load impacts are much lower than they were during summer months, at 0.007 kWh/hour on non-holiday weekdays and not statistically significantly different from zero on weekends and holidays. Off-peak period load increases are somewhat larger during winter than summer, at 0.006 kWh/hour vs. 0.003 kWh/hour during the summer. Finally, in contrast to summer load impacts, which reflected a net conservation effect, total usage *increased* somewhat during the winter season, by 0.5 percent on non-holiday weekdays and 0.7 percent on weekends and holidays.

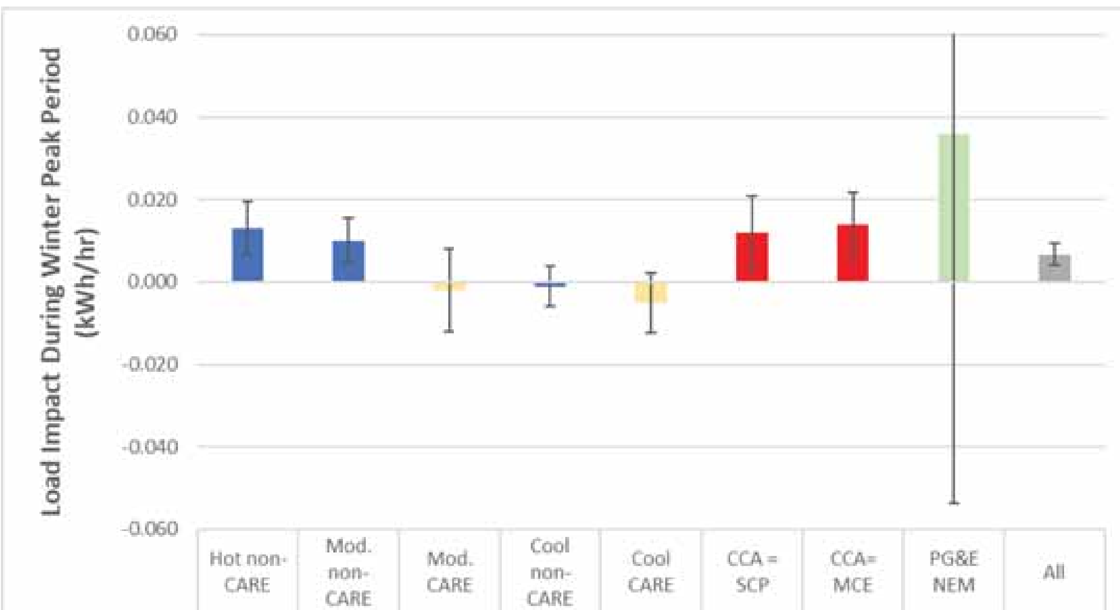
Table 4.4: Winter Average Hourly Load Impacts for PG&E, Weighted Across the Analysis Segments

Day Type	Pricing Period	Reference (kWh/hr)	Impact (kWh/hr)	% Impact
Non-holiday weekday	Peak	0.793	0.007	0.9%
	Off-peak	0.553	-0.006	-1.1%
	All Hours	0.603	-0.003	-0.5%
Weekend/Holiday	Peak	0.821	0.003	0.3%
	Off-peak	0.597	-0.006	-1.0%
	All Hours	0.644	-0.004	-0.7%

Positive impact values = load reductions
Negative impact values = load increases
Shaded cell indicates that the estimated load impact is not statistically significant

Figure 4.3 shows the winter peak-period load impacts by segment. The bar colors correspond to those used in Figure 4.1. While winter peak-period load impacts are lower than those of summer, the comparisons across groups are qualitatively similar. That is, load impacts tend to be higher in hotter climate regions and for non-CARE customers. Notice the high level of uncertainty around the estimated impact for NEM customers (with the error bar truncated at the high end to allow for better visibility of the other segments).

Figure 4.3: Winter Average Peak-Period Load Impact by Segment, Non-holiday Weekdays



	Hot non-CARE	Mod. non-CARE	Mod. CARE	Cool non-CARE	Cool CARE	CCA = SCP	CCA= MCE	PG&E NEM	All
Percent Impact	1.4%	1.3%	-0.3%	-0.1%	-0.8%	1.5%	1.6%	3.5%	0.9%
Absolute Impact	0.013	0.010	-0.002	-0.001	-0.005	0.012	0.014	0.036	0.007

Tables 4.5 and 4.6 expand upon the information shown in Figure 4.3, showing the estimated impacts for the off-peak period, the peak period, and all hours. Table 4.5 contains results for winter non-holiday weekdays while Table 4.6 contains results for winter weekends and holidays. Gray shading indicates estimated load impacts that are not statistically significantly different from zero, which applies to many of the included estimates. The Hot non-CARE segment is the only group with a statistically significant estimate in all time periods of both day types.

Table 4.5: Average Load Impacts by TOU Pricing Period, Winter Non-holiday Weekdays

Segment	Off-peak			Peak			All Hours		
	Ref.	Impact	% Impact	Ref.	Impact	% Impact	Ref.	Impact	% Impact
Hot non-CARE	0.680	-0.012	-1.8%	0.968	0.013	1.4%	0.740	-0.007	-0.9%
Mod. non-CARE	0.553	-0.005	-0.9%	0.781	0.010	1.3%	0.600	-0.002	-0.3%
Mod. CARE	0.545	-0.013	-2.4%	0.777	-0.002	-0.3%	0.594	-0.011	-1.8%
Cool non-CARE	0.475	-0.004	-0.8%	0.679	-0.001	-0.1%	0.517	-0.003	-0.6%
Cool CARE	0.440	-0.006	-1.4%	0.650	-0.005	-0.8%	0.484	-0.006	-1.2%
CCA = SCP	0.550	-0.002	-0.3%	0.809	0.012	1.5%	0.604	0.001	0.2%
CCA= MCE	0.583	-0.002	-0.3%	0.857	0.014	1.6%	0.640	0.002	0.2%
PG&E NEM	0.091	0.002	1.8%	1.027	0.036	3.5%	0.286	0.009	3.1%
All	**0.553**	**-0.006**	**-1.1%**	**0.793**	**0.007**	**0.9%**	**0.603**	**-0.003**	**-0.5%**

Positive impact values = load reductions
Negative impact values = load increases
Shaded cell indicates that the estimated load impact is not statistically significant

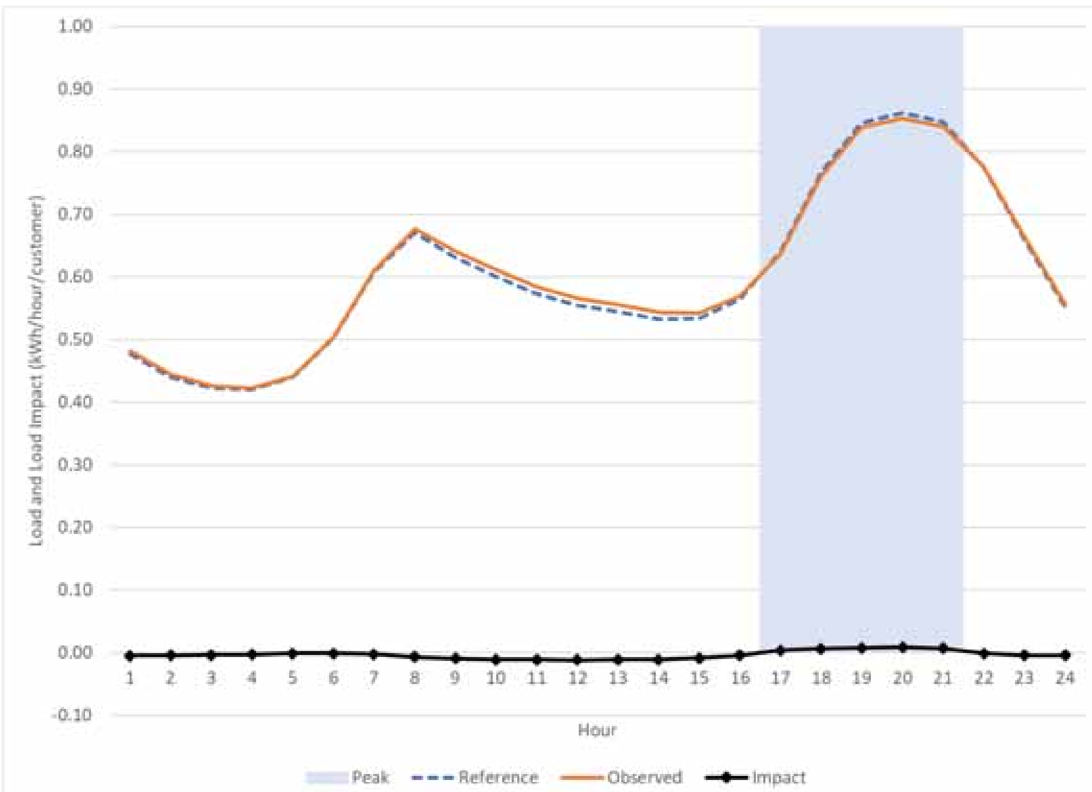
Table 4.6: Average Load Impacts by TOU Pricing Period, Winter Weekends/Holidays

Segment	Off-peak			Peak			All Hours		
	Ref.	Impact	% Impact	Ref.	Impact	% Impact	Ref.	Impact	% Impact
Hot non-CARE	0.737	-0.013	-1.8%	1.006	0.007	0.7%	0.793	-0.009	-1.1%
Mod. non-CARE	0.604	-0.004	-0.6%	0.823	0.006	0.8%	0.650	-0.002	-0.3%
Mod. CARE	0.590	-0.011	-1.9%	0.790	-0.005	-0.6%	0.631	-0.010	-1.6%
Cool non-CARE	0.507	-0.005	-1.0%	0.704	-0.005	-0.6%	0.548	-0.005	-0.9%
Cool CARE	0.471	-0.005	-1.1%	0.646	-0.007	-1.1%	0.507	-0.006	-1.1%
CCA = SCP	0.599	-0.001	-0.1%	0.835	0.007	0.8%	0.648	0.001	0.2%
CCA= MCE	0.619	-0.003	-0.4%	0.878	0.010	1.1%	0.673	0.000	0.0%
PG&E NEM	0.139	-0.003	-2.3%	1.078	0.020	1.8%	0.335	0.002	0.5%
All	**0.597**	**-0.006**	**-1.0%**	**0.821**	**0.003**	**0.3%**	**0.644**	**-0.004**	**-0.7%**

Positive impact values = load reductions
Negative impact values = load increases
Shaded cell indicates that the estimated load impact is not statistically significant

Figure 4.4 shows the average hourly reference loads, observed loads, and load impacts across all segments for winter non-holiday weekdays. The peak-period hours are highlighted in blue. The blue dashed line represents the reference load, the solid orange line represents the observed load, and the black line with diamond markers is the estimated load impact. The lower peak-period load impacts relative to summer are evident in the figure (as compared with Figure 4.2, which shows the corresponding results for the summer months). Recall that the peak to off-peak price difference is smaller in winter than summer, which may explain the lower load impacts in winter.

Figure 4.4: Winter Non-holiday Weekday Hourly Load and Load Impact, All Segments



4.3 Annual Load Impacts

Table 4.7 combines the seasonal information in Tables 4.1 and 4.4 to show the annual reference loads and load impacts at the PG&E system level. Notice that the seasonal all-hours load impacts cancel out (*i.e.*, the summer conservation effect is offset by the winter usage increase). For the year, peak-period usage is reduced by 0.017 kWh/hour (2 percent) on non-holiday weekdays and 0.013 kWh/hour (1.5 percent) on weekends and holidays.

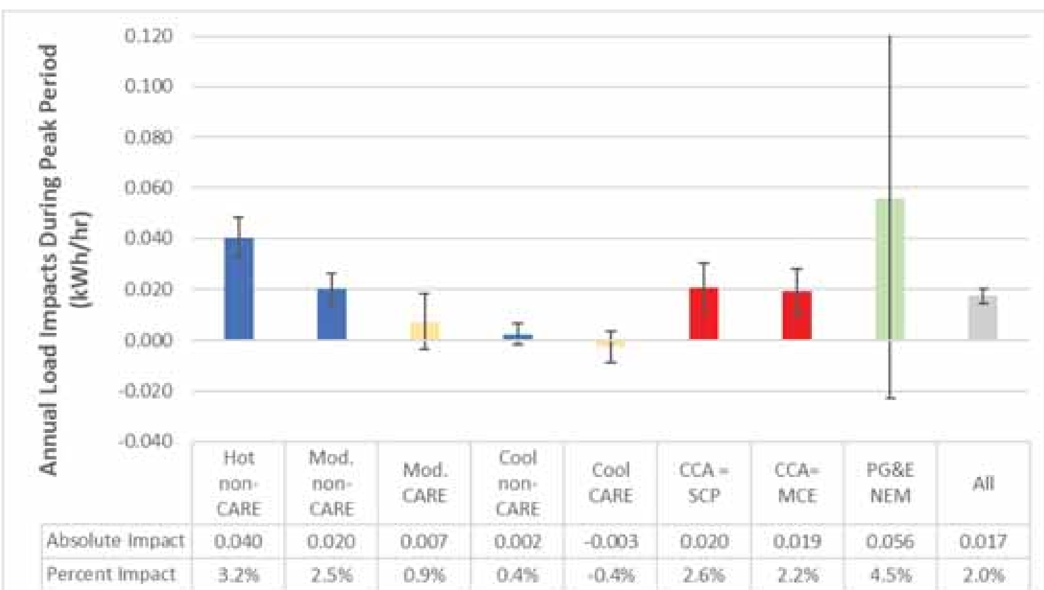
Table 4.7: Annual Average Hourly Load Impacts for PG&E, Weighted Across the Analysis Segments

Day Type	Pricing Period	Reference (kWh/hr)	Impact (kWh/hr)	% Impact
Non-holiday weekday	Peak	0.843	0.017	2.0%
	Off-peak	0.564	-0.005	-0.9%
	All Hours	0.622	0.000	-0.1%
Weekend/Holiday	Peak	0.875	0.013	1.5%
	Off-peak	0.607	-0.005	-0.8%
	All Hours	0.663	-0.001	-0.2%

Positive impact values = load reductions
Negative impact values = load increases
Shaded cell indicates that the estimated load impact is not statistically significant

Figure 4.5 shows the annual peak-period load impacts by segment. The highest load impacts are in the hot and moderate non-CARE segments as well as the two CCAs. The NEM and CARE customer load impacts are not statistically significantly different from zero.

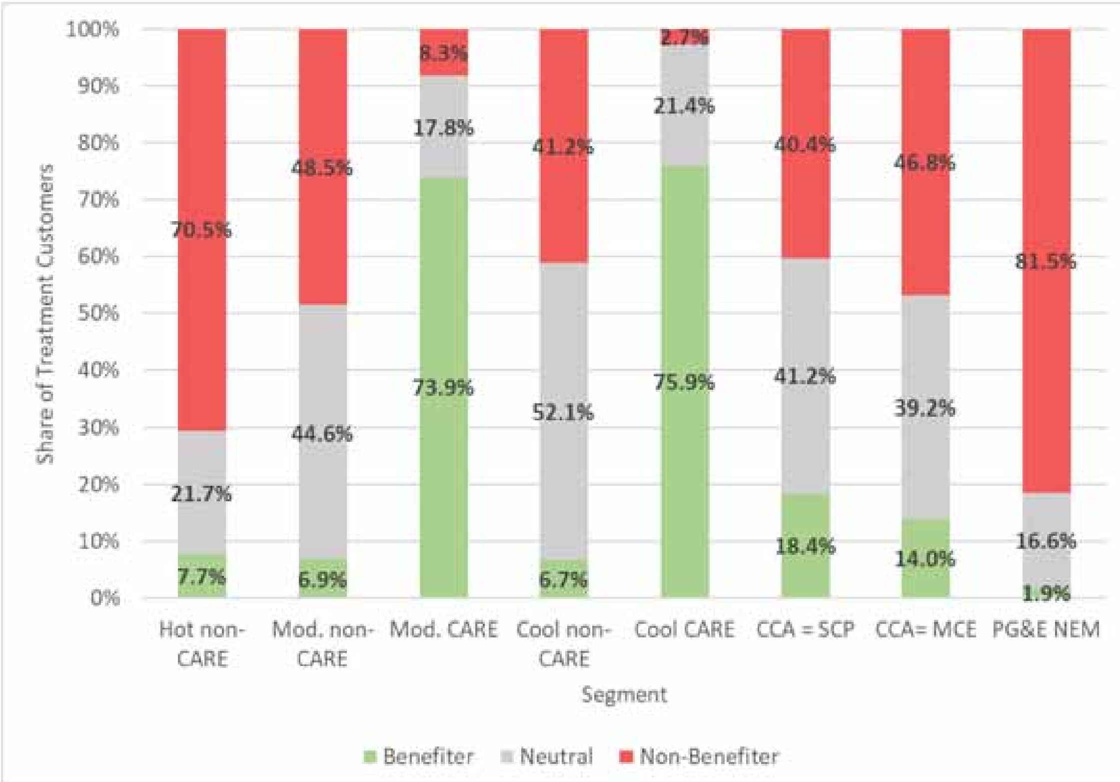
Figure 4.5: Annual Average Peak-Period Load Impact by Segment, Non-holiday Weekdays



5. Structural Bill Impacts

This section contains a summary of structural bill impacts in each segment using methods described in Section 3.2. Figure 5.1 shows the share of customers in each segment in each of three structural bill impact categories: “Neutral” is defined as an annual structural bill impact less than $10; "Benefiters" have a structural bill decrease on E-TOU-C3 of $10 or more; and "Non-benefiters" have a structural bill increase of $10 or more.

Figure 5.1: Share of Customers by Segment and Structural Bill Impact Category



The following conclusions can be drawn from the figure:

- CARE customers much more likely to be structural benefiters (*e.g.*, in the moderate climate region, 73.9 percent of CARE customers vs. 6.9 percent of non-CARE customers are structural benefiters);
- The proportion of non-benefiters is higher in hotter climate zones (*e.g.*, 70.5 percent of hot climate region non-CARE customers vs. 48.5 percent of moderate climate region non-CARE customers); and
- NEM customers are primarily non-benefiters (81.5 percent in the PG&E NEM segment).

Figure 5.2 goes beyond the qualitative characterization of the structural bill impacts to shows the average annual bill change for benefiters and non-benefiters by segment. The sign was changed for the benefiters (from negative to positive) to allow for easier comparison of the relative magnitudes.

Figure 5.2: Average Annual Bill Impact by Segment and Structural Bill Impact Category

	Hot non-CARE	Mod. non-CARE	Mod. CARE	Cool non-CARE	Cool CARE	CCA = SCP	CCA= MCE	PG&E NEM
Benefiter	242	209	23	179	14	80	119	304
Non-Benefiter	66	42	20	30	21	39	42	78
Benefiter Share	8%	7%	74%	7%	76%	18%	14%	2%
Non-Benefiter Share	71%	49%	8%	41%	3%	40%	47%	82%

The figure shows the following:

- Structural bill decreases for benefiters tend to be larger than the structural bill increases for non-benefiters. This is true in all segments except the cool climate region CARE segment. For example, benefiters in the hot non-CARE segment have an average structural bill decrease of $242 per year while non-benefiters in the same segment have an average structural bill increase of $66 per year.
- CARE customers have lower structural bill impacts than non-CARE customers, as seen in the moderate and cool climate regions.

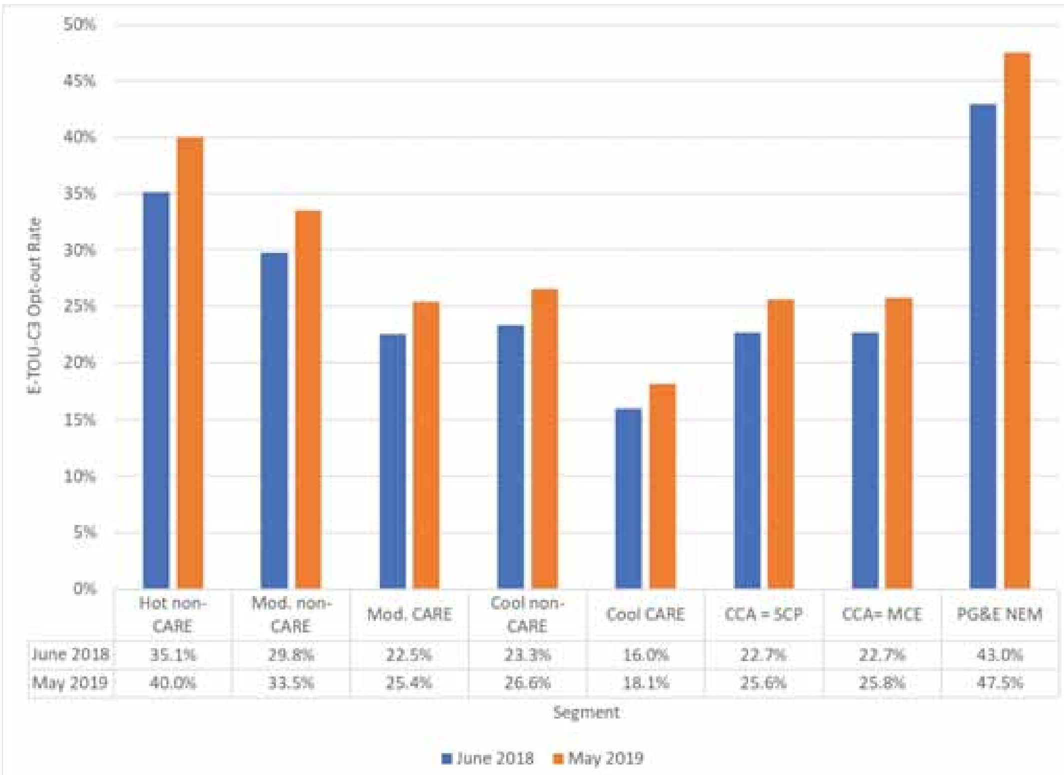
Overall, we observe that while there are more structural non-benefiters, the structural benefiters tend to “win” by more than the non-benefiters “lose”, on average.

6. Opt-out Summary

Pilot customers who are defaulted onto E-TOU-C3 may elect to take service on one of PG&E’s other rates, including the E-1 tiered rate and two TOU rates (E-TOU-A and E-TOU-B). In this section, we present the E-TOU-C3 opt-out rates at the beginning and end of the first year (June 2018 through May 2019), by segment. In addition, we show the participation rates in the other rate options. In each case, the opt-out or participation rate is calculated excluding customers who terminated service with PG&E (*e.g.*, due to a change of address).

Figure 6.1 shows the E-TOU-C3 opt-out rates by segment. The blue bars reflect opt-outs as of the beginning of our analysis period (June 1, 2018). The orange bars reflect opt-outs as of the end of our analysis period (May 31, 2019).

Figure 6.1: E-TOU-C3 Opt-out Rates by Segment



The figure reflects the following observations:

- Opt-out rates tend to be higher in hotter climate regions;
- Opt-out rates tend to be higher for non-CARE customers;
- NEM customer opt-out rates are high relative to other customer groups; and
- Most opt-outs occurred prior to the rate going into effect.

Figure 6.2 shows that some of the customers who opted out of E-TOU-C3 went to one of the other optional TOU rates. E-TOU-B may be appealing to higher-use customers because it omits the baseline credit present in the other TOU options. E-TOU-A may be appealing due to an earlier peak period (3 to 8 p.m.) and the fact that holidays and weekends are all off-peak (this is also true of E-TOU-B, whereas the E-TOU-C3 pricing periods apply to all days). By the end of the year, some segments had more than 10 percent of the pilot customers on one the voluntary TOU rates. This shows that not all opt-outs are equal – customers opting out to another TOU rate have not displayed an aversion to the concept of TOU pricing, whereas those who opt out to E-1 may have.

Figure 6.2: E-TOU-A and E-TOU-B Shares by Segment

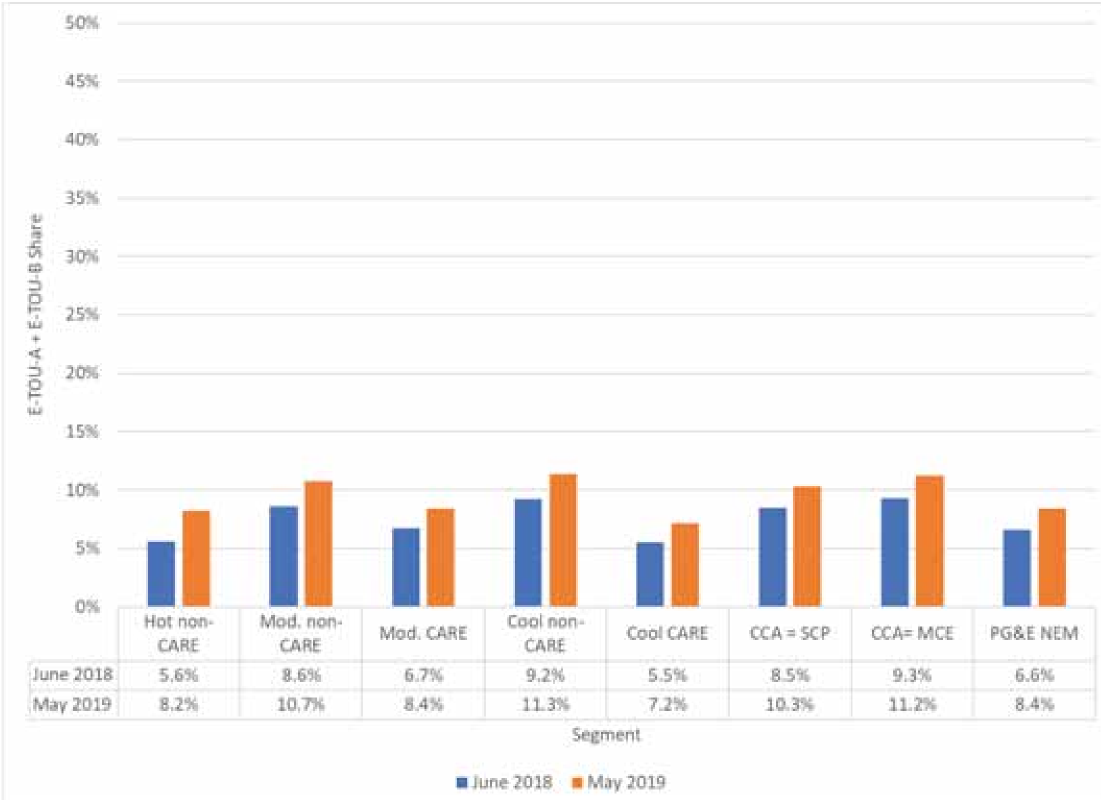
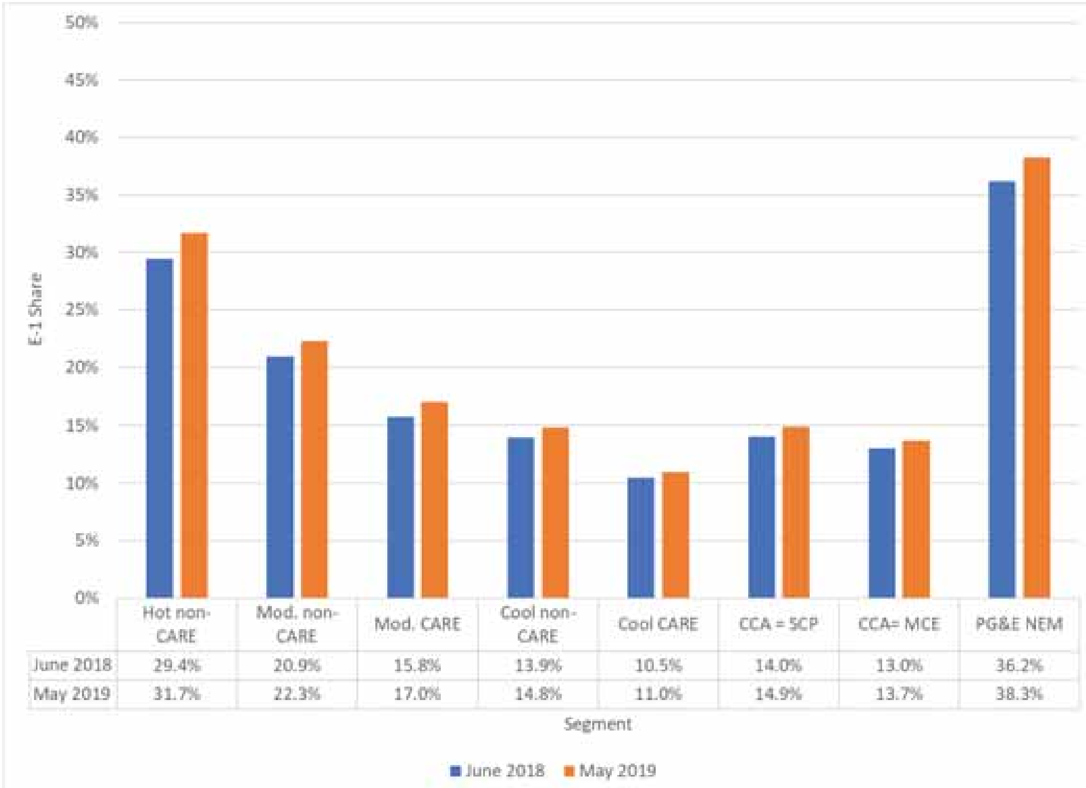


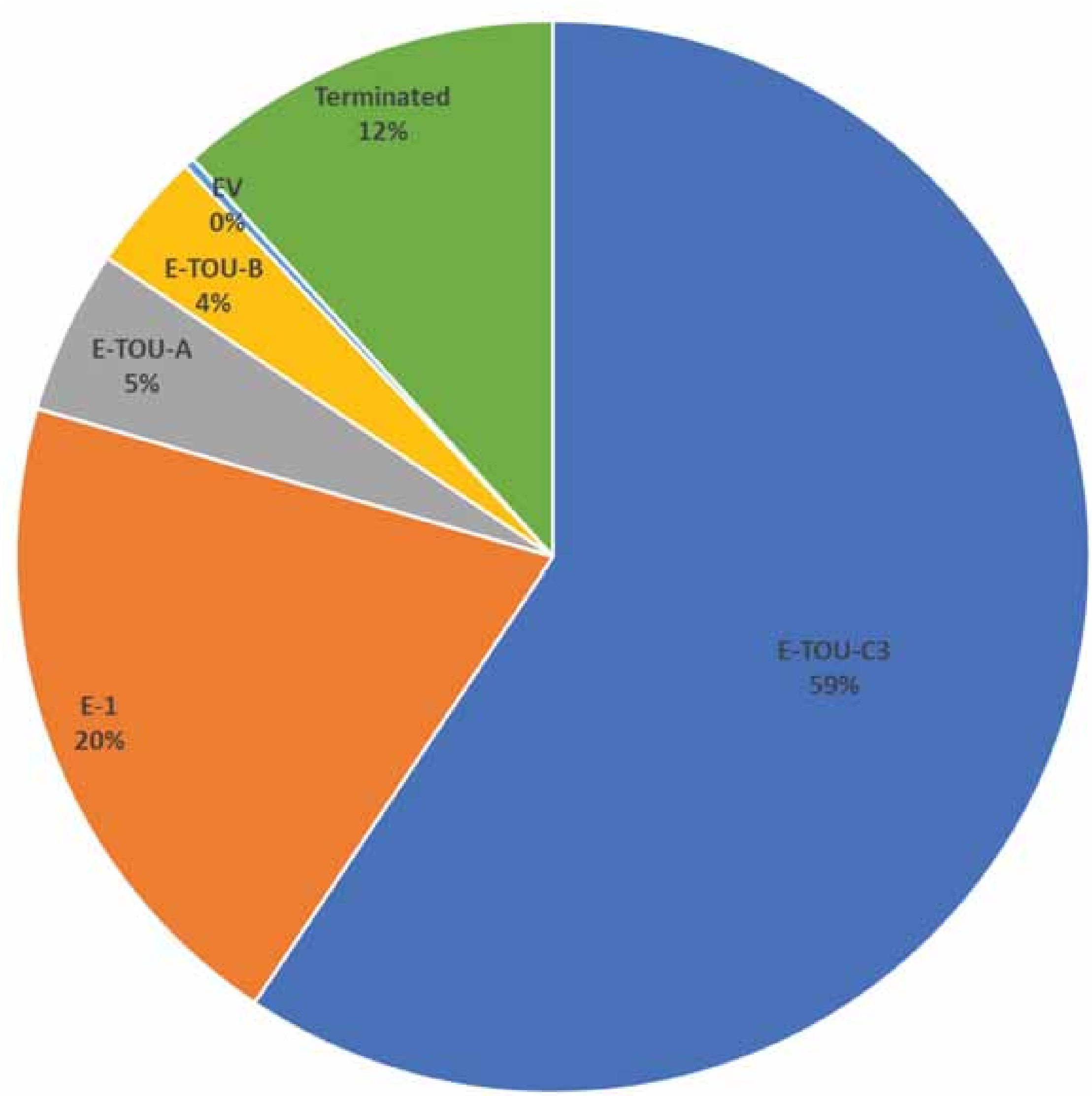
Figure 6.3 shows the shares of pilot customers on E-1 at the beginning and end of the analysis year. This figure mirrors Figure 6.1, with most adoptions occurring prior to the E-TOU-C3 going into effect and with the same variations across segments (*e.g.*, higher participation in hotter climates and for non-CARE customers).

Figure 6.3: E-1 Share by Segment



In Figures 6.1 through 6.3, the denominator for the opt-out or participation rates was the number of pilot service accounts continuing to take service with PG&E. Because of customer attrition (*e.g.*, customers moving), this total declines over time. Figure 6.4 changes the perspective to show the final rate of all pilot customers at the end of the analysis year (*i.e.*, as of May 31, 2019). The shares are calculated according to the number of customers in each pilot segment, not weighted to reflect the representativeness of PG&E’s system. This shows that 12 percent of the pilot service accounts terminated service with PG&E, 20 percent took service on E-1, 9 percent took service on one of the other voluntary TOU rates, and 59 percent took service on E-TOU-C3.

Figure 6.4: Share of Treatment Customers by End-of-Year Rate



7. Key Findings

The first year of the Default TOU pilot has produced a number of key findings, showing that outcomes can vary substantially across seasons and customer segments.

7.1 Load Impacts

Key findings regarding customer load impacts include:

- Peak-period load impacts tend to be higher in summer than winter. Across all segments on non-holiday weekdays, the summer peak-period impact is 0.038 kWh/hour (4.0 percent) vs. 0.007 kWh/hour (0.9 percent) in winter. This could reflect customer response to the higher peak to off-peak price differential in summer.

- The 0.038 kWh/hour (4 percent) summer peak-period load impact translates to roughly 4 MWh/hr of aggregate load impact from Default pilot customers.[13]
- Within summer, the peak-period load impacts are highest for non-CARE customers in the hot climate region, at 0.095 kWh/hour vs. 0.038 across all segments.
- Peak-period load impacts in the CCAs approximate those of the moderate climate region segments.
- Within season, weekend/holiday reference loads tend to be higher than those of non-holiday weekdays, but the load impacts are somewhat lower in level and percentage terms. For example, the summer peak-period reference load is 0.944 kWh/hour on non-holiday weekdays and 0.981 on weekends/holidays. In contrast, the load impact is 0.038 kWh/hour (4.0 percent of reference load) on non-holiday weekdays but 0.034 kWh/hour (3.4 percent of reference load) on weekends/holidays. Because prices do not differ by day of week, this difference is likely due to differences in customer demand and/or preferences across day types.
- The estimates reflect some overall conservation during the summer, but an overall load increase during the winter. The combined effect resulted in annual usage changes that were not statistically significantly different from zero.
- There is evidence for load shifting, as decreases in peak-period usage are accompanied by increase in off-peak period usage. For example, summer off-peak usage on non-holiday weekdays increased by 0.5 percent. Note that this result is largely driven by non-CARE customers in the hot climate region.

7.2 Structural Bill Impacts

Key findings regarding structural bill impacts (the bill impact prior to any customer demand response to the TOU rates) include:

- Most non-CARE customers are structural non-benefiters while most CARE customers are structural benefiters.
- The share of non-benefiters is higher in hotter climate regions. For non-CARE customers, the non-benefiter percentage is 70.5 percent in the hot climate region, 48.5 percent in the moderate climate region, and 41.2 percent in the cool climate region.
- Most NEM customers are non-benefiters (81.5 percent).
- While a higher share of customers is structural non-benefiters, the structural bill decrease for benefiters tends to be larger than the structural bill increase for non-benefiters. For example, for non-CARE customers in the hot climate region,

[13] This calculation is based on 109,026 treatment customers participating in E-TOU-C3, E-TOU-A, or E-TOU-B. The total Default TOU load impact is expected to scale with the number of defaulted customers.

the average structural bill decrease for benefiters is $242 per year, while the average structural bill increase for non-benefiters is $66 per year.

7.3 Customer Opt-outs

Key findings regarding customer opt-out behavior include:

- Most of the opt-outs to the standard tiered E-1 rate occurred during the notification period, before the customer's rate plan was changed to the E-TOU-C3 rate plan.
- Some of the customers who opted out of the Default E-TOU-C3 selected a voluntary TOU rate (E-TOU-A or E-TOU-B) rather than E-1. This accounts for more than 10 percent of the customers in some of the segments.
- Opt-outs to E-1 tend to be higher as the climate region becomes hotter (hot > moderate > cool).
- Opt-outs to E-1 tend to be higher for non-CARE customer segments than CARE segments.
- The opt-out behavior in the two CCAs approximates that of the moderate climate region.

Appendices

Appendix A Detailed Load Impact Tables

Appendix B Match Quality Summary

Appendix A. Detailed Load Impact Tables

An Excel-based table generator containing detailed load impact tables accompanies this report. It provides load impacts by season, day type (non-holiday weekdays versus weekends and holidays), and analysis segment.

Appendix B. Match Quality

Appendix Table 1 shows the results of our summer control-group matching process, expressing the match quality using mean percentage error (MPE) and mean absolute percentage error (MAPE) across the 24 hours and peak-period hours for each of the hot and moderate non-holiday weekday load profiles. MPE can be thought of as a measure of bias while MAPE assesses accuracy. For matching purposes, each segment was divided into two sub-segments according to location (*e.g.*, north vs. south). Treatment customers were matched to a control-group customer in their sub-segment, guaranteeing a perfect match on the characteristics that define the sub-segment.

Appendix Table 1: Comparison of Treatment and Control-group Customer Loads in the Pre-treatment Year by Segment and Day Type, Summer

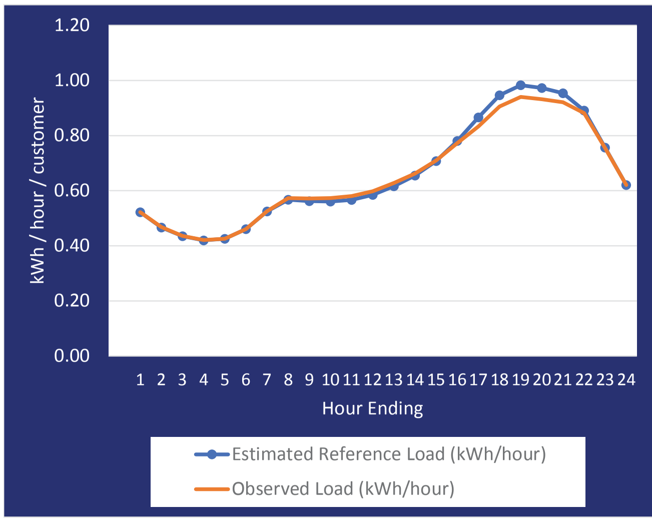
Segment	Profile	All Hours		Peak Hours	
		MPE	MAPE	MPE	MAPE
1: Hot non-CARE	Hot	-1.0%	1.1%	-1.0%	1.0%
	Moderate	-0.5%	1.3%	-0.4%	0.5%
2: Moderate non-CARE	Hot	-1.2%	1.4%	-1.7%	1.7%
	Moderate	0.0%	1.5%	-0.3%	0.6%
3: Moderate CARE	Hot	-0.9%	1.6%	-1.8%	1.8%
	Moderate	0.0%	1.8%	-1.1%	1.1%
4: Cool non-CARE	Hot	-0.2%	1.1%	-1.2%	1.2%
	Moderate	-0.3%	1.3%	-1.2%	1.2%
5: Cool CARE	Hot	-0.1%	1.2%	-1.0%	1.0%
	Moderate	-0.4%	1.5%	-1.7%	1.7%
6: CCA = SCP	Hot	-0.2%	1.3%	-1.2%	1.2%
	Moderate	-1.1%	1.8%	-1.9%	1.9%
7: CCA= MCE	Hot	-1.0%	1.4%	-1.3%	1.3%
	Moderate	-0.6%	1.5%	-0.7%	0.7%
8: NEM	Hot	-2.0%	4.5%	-0.6%	0.6%
	Moderate	-1.7%	5.5%	3.5%	3.5%

Appendix Table 2 provides the same summary for the winter analysis. In this case, the load profiles correspond to cold and moderate non-holiday weekdays.

Appendix Table 2: Comparison of Treatment and Control-group Customer Loads in the Pre-treatment Year by Segment and Day Type, Winter

Segment	Profile	All Hours		Peak Hours	
		MPE	MAPE	MPE	MAPE
1: Hot non-CARE	Cold	-1.5%	1.5%	-1.8%	1.8%
	Moderate	-0.1%	1.3%	-1.2%	1.2%
2: Moderate non-CARE	Cold	-1.3%	1.5%	-1.7%	1.7%
	Moderate	0.2%	1.4%	-1.1%	1.1%
3: Moderate CARE	Cold	-1.7%	2.3%	-2.5%	2.5%
	Moderate	-0.2%	1.8%	-1.6%	1.7%
4: Cool non-CARE	Cold	-1.6%	1.8%	-2.0%	2.0%
	Moderate	0.2%	1.2%	-0.5%	0.7%
5: Cool CARE	Cold	-1.8%	2.0%	-2.6%	2.6%
	Moderate	0.1%	1.8%	-1.5%	1.5%
6: CCA = SCP	Cold	-1.0%	1.3%	-1.8%	1.8%
	Moderate	-0.3%	1.2%	-1.3%	1.3%
7: CCA= MCE	Cold	-1.4%	1.8%	-1.8%	1.8%
	Moderate	-0.3%	1.4%	-1.7%	1.7%
8: NEM	Cold	-16.6%	18.6%	-6.6%	6.6%
	Moderate	-5.1%	6.4%	-4.6%	4.6%

Utility	Pacific Gas & Electric
Rate	Default E-TOU-C3 Pilot
Season	Summer
Day type	Non-holiday Weekday
Segment	All



PG&E Residential Default TOU Pilot First-Year Load Impacts

Hour Ending	Estimated Reference Load (kWh/hour)	Observed Load (kWh/hour)	Estimated Load Impact (kWh/hour)	Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hour) 10th %ile	30th %ile	50th %ile	70th %ile	90th %ile
1	0.522	0.522	0.000	61.0	-0.002	-0.001	0.000	0.001	0.002
2	0.466	0.468	-0.001	60.0	-0.003	-0.002	-0.001	-0.001	0.000
3	0.435	0.436	-0.001	59.2	-0.003	-0.001	-0.001	0.000	0.001
4	0.420	0.421	-0.001	58.5	-0.003	-0.002	-0.001	0.000	0.001
5	0.425	0.426	0.000	57.9	-0.002	-0.001	0.000	0.000	0.001
6	0.461	0.460	0.000	57.4	-0.001	0.000	0.000	0.001	0.002
7	0.525	0.526	-0.001	57.2	-0.003	-0.002	-0.001	0.000	0.001
8	0.567	0.573	-0.006	58.6	-0.007	-0.006	-0.006	-0.005	-0.004
9	0.562	0.571	-0.009	61.9	-0.011	-0.010	-0.009	-0.009	-0.008
10	0.561	0.573	-0.012	66.0	-0.014	-0.013	-0.012	-0.011	-0.010
11	0.567	0.580	-0.013	70.2	-0.016	-0.014	-0.013	-0.012	-0.011
12	0.585	0.598	-0.013	74.3	-0.016	-0.015	-0.013	-0.012	-0.010
13	0.616	0.628	-0.012	77.3	-0.015	-0.013	-0.012	-0.010	-0.008
14	0.655	0.663	-0.008	79.5	-0.011	-0.009	-0.008	-0.006	-0.004
15	0.707	0.710	-0.002	80.9	-0.006	-0.004	-0.002	-0.001	0.001
16	0.780	0.773	0.008	81.3	0.005	0.007	0.008	0.009	0.011
17	0.866	0.833	0.033	80.7	0.030	0.032	0.033	0.035	0.036
18	0.947	0.906	0.041	79.2	0.038	0.040	0.041	0.042	0.044
19	0.983	0.940	0.042	76.6	0.040	0.041	0.042	0.044	0.045
20	0.973	0.932	0.040	72.7	0.038	0.039	0.040	0.041	0.043
21	0.954	0.921	0.033	68.5	0.031	0.032	0.033	0.034	0.035
22	0.891	0.881	0.010	65.8	0.007	0.009	0.010	0.010	0.012
23	0.756	0.755	0.001	64.0	-0.001	0.000	0.001	0.002	0.003
24	0.621	0.621	0.000	62.5	-0.002	-0.001	0.000	0.001	0.002

Average by Period:	Estimated Reference Load (kWh/hour)	Observed Load (kWh/hour)	Estimated Load Impact (kWh/hour)	Average Temperature (°F)	Uncertainty Adjusted Impact (kWh/hour) 10th %ile	30th %ile	50th %ile	70th %ile	90th %ile	Average % Load Impact
Daily	0.660	0.655	0.005	68.0	0.004	0.005	0.005	0.006	0.007	0.8%
Peak	0.944	0.907	0.038	75.5	0.036	0.037	0.038	0.039	0.040	4.0%
Off-Peak	0.585	0.589	-0.003	66.0	-0.005	-0.004	-0.003	-0.003	-0.002	-0.5%

Summer is defined as June through September 2018
Winter is defined as October 2018 through May 2019