2019 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-of-Use Rates

Ex-Post and *Ex-Ante* Report

CALMAC Study ID PGE0444

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Confidential information is redacted and denoted with black highlighting: [redacted]

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Executive Summary

This report documents *ex-post* and *ex-ante* load impact evaluations for Pacific Gas and Electric Company's ("PG&E") residential time-of-use (TOU) rates for program year 2019. Only customers not served under net energy metering (NEM) are included in the analysis. The report addresses the two primary objectives of providing: 1) estimates of *ex-post* load impacts for E-TOU-A, E-TOU-B, and E-TOU-C3 customers in 2019, and 2) *ex-ante* forecasts of load impacts for 2020 through 2030 that are based on PG&E's enrollment forecasts and the *ex-post* load impact estimates produced in this study.

ES.1 Resources Covered

In 2019, PG&E offered three options for customers who wished to enroll in a TOU rate plan. E-TOU-A and E-TOU-B were introduced for Residential customers in 2016 while E-TOU-C3 became available in 2018. E-TOU-A was closed to new enrollment at the end of 2019 and is scheduled for termination in 2020. E-TOU-B will close to new enrollment at the end of April 2020 but will remain available to current enrollees until the end of 2025.

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 was limited to a subset of the total eligible population[1], 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.

All three E-TOU rates have 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 do not. The peak periods are defined as follows: E-TOU-A is 3 p.m. to 8 p.m. on non-holiday weekdays; E-TOU-B is 4 p.m. to 9 p.m. on non-holiday weekdays; and E-TOU-C3 is 4 p.m. to 9 p.m. on all days. E-TOU-A and E-TOU-C3 include a tiered rate structure in which customers receive a $/kWh credit for usage up to the amount of the tariff-defined baseline quantities; the latter varies geographically by Baseline Territory. This feature makes those two rates more appealing to low-use customers, while E-TOU-B is likely to appeal to higher-use customers due to the absence of the tiered structure.

ES.2 Evaluation Methodologies

The evaluation involved selecting quasi-experimental matched control groups and conducting difference-in-differences estimation using regression analysis. The *ex-post* analysis was conducted for former E-1 customers who newly enrolled in E-TOU-A, E-

[1] 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.

TOU-B, or E-TOU-C3; TOU customers enrolled in E-6 are not in scope of this study. To select the control-group, customers were matched on pre-enrollment load data from October 2017 to September 2018. Lastly, to estimate the impacts from enrolling in a TOU rate, differences between TOU and the matched control group customer loads were estimated for the average and peak load weekday in each month from October 2018 to September 2019. In addition, we extended the *ex-post* evaluations conducted as part of the prior year evaluation[2] as a test of the persistence of TOU load impacts.

ES.3 Ex-Post Load Impacts

Table ES.1 shows the estimated peak-period load impacts for the E-1 to E-TOU-A customers. Results are shown from October 2018 through September 2019, with each row representing the month's average weekday. Non-NEM enrollment reached approximately 33,000 during the program year. Percentage load impacts ranged from 0.9 percent in October to 8.9 percent in January. Note that the regression sample is smallest in these early months, as the models include only customers enrolled on or after October 1, 2018. (Enrollments reflect total non-NEM enrollment rather than the regression sample size.) The results get more robust as the program year proceeds. Some of the estimated load impacts (October, May, and June) are not statistically significantly different from zero.

[2] "2018 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-of-Use Rates," CALMAC Study ID PGE0430.

Table ES.1: E-1 to E-TOU-A Peak Load Reductions – *Average Weekday by Month*[3]

Month	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
		Peak Ref. Load (MW)	Peak Load Impact (MW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
Oct 2018	25,324	11.8	0.1	0.46	0.004	0.9% [-2.0% - 3.7%]	69.0
Nov 2018	23,848	14.2	0.5	0.59	0.023	3.8% [1.3% - 6.4%]	59.5
Dec 2018	24,226	17.5	1.2	0.72	0.048	6.6% [3.9% - 9.3%]	54.5
Jan 2019	29,077	20.0	1.8	0.69	0.061	8.9% [6.4% - 11.4%]	56.0
Feb 2019	25,686	18.1	0.8	0.71	0.029	4.2% [2.2% - 6.1%]	51.7
Mar 2019	29,428	16.7	0.8	0.57	0.026	4.5% [2.8% - 6.2%]	58.6
Apr 2019	30,297	15.5	0.9	0.51	0.030	5.9% [4.3% - 7.4%]	67.3
May 2019	31,095	14.7	0.2	0.47	0.007	1.4% [-0.7% - 3.5%]	66.3
Jun 2019	31,473	18.5	0.2	0.59	0.007	1.3% [-0.9% - 3.4%]	81.8
Jul 2019	33,120	20.1	0.8	0.61	0.024	3.9% [1.4% - 6.4%]	81.6
Aug 2019	30,675	20.6	0.7	0.67	0.024	3.6% [1.6% - 5.7%]	85.1
Sep 2019	28,308	16.2	0.4	0.57	0.016	2.8% [1.0% - 4.6%]	80.8

Table ES.2 shows the corresponding results for the E-1 to E-TOU-B customers. Non-NEM enrollment in E-TOU-B reached approximately 34,000 during the program year. As expected given the rate design (which benefits higher-use customers due to the absence of the tier structure), the per-customer reference loads for E-TOU-B customers are considerably higher than those of the E-TOU-A customers. In addition, both the level and percentage of the E-TOU-B per-customer load impacts is higher than those of E-TOU-A in most months.

[3] The brackets accompanying the percentage load impacts represent the 10th and 90th percentile uncertainty adjusted load impacts.

Table ES.2: E-1 to E-TOU-B Peak Load Reductions – *Average Weekday by Month*

Month	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
		Peak Ref. Load (MW)	Peak Load Impact (MW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
Oct 2018	26,112	47.3	1.8	1.81	0.070	3.9% [-0.9% - 8.7%]	68.2
Nov 2018	24,119	49.2	4.4	2.04	0.182	8.9% [4.0% - 13.8%]	57.6
Dec 2018	24,909	54.7	3.2	2.19	0.127	5.8% [2.4% - 9.3%]	52.5
Jan 2019	29,859	59.1	1.7	1.98	0.058	2.9% [0.2% - 5.7%]	54.1
Feb 2019	26,221	51.5	0.1	1.97	0.002	0.1% [-2.5% - 2.7%]	50.0
Mar 2019	30,075	50.8	1.6	1.69	0.053	3.1% [0.7% - 5.5%]	57.3
Apr 2019	31,120	52.7	3.6	1.69	0.117	6.9% [4.4% - 9.4%]	66.5
May 2019	31,933	51.8	2.4	1.62	0.074	4.6% [2.2% - 7.0%]	65.8
Jun 2019	32,341	70.6	3.6	2.18	0.112	5.1% [3.5% - 6.8%]	82.1
Jul 2019	34,087	76.1	3.5	2.23	0.103	4.6% [3.0% - 6.2%]	82.6
Aug 2019	32,228	80.0	5.3	2.48	0.164	6.6% [5.2% - 8.0%]	85.3
Sep 2019	31,030	64.3	3.1	2.07	0.101	4.9% [3.4% - 6.4%]	80.3

Table ES.3 shows the monthly peak-period load impacts for the customers who voluntarily joined E-TOU-C3 from E-1. Load impacts varied considerably across months, from -0.013 in May to 0.231 in November. Notice the broad confidence interval in the percentage load impacts, which likely reflects uncertainty due to small sample sizes.

Table ES.3: E-1 to Default E-TOU-C Peak Load Reductions – *Average Weekday by Month*

Month	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
		Peak Ref. Load (MW)	Peak Load Impact (MW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
Oct 2018	3,233	[redacted]					69.4
Nov 2018	3,757	5.7	0.9	1.53	0.231	15.1% [5.4% - 24.8%]	57.7
Dec 2018	5,284	7.9	0.5	1.50	0.095	6.3% [0.8% - 11.9%]	52.5
Jan 2019	7,926	11.1	0.9	1.40	0.118	8.4% [2.8% - 14%]	54.2
Feb 2019	8,304	11.4	0.6	1.37	0.076	5.5% [1.9% - 9.1%]	50.4
Mar 2019	10,667	12.3	0.6	1.16	0.054	4.7% [1.2% - 8.1%]	57.6
Apr 2019	12,403	13.0	(0.0)	1.05	0.000	0.0% [-5.9% - 5.9%]	66.8
May 2019	13,937	13.9	(0.2)	1.00	-0.013	-1.3% [-5.4% - 2.8%]	66.2
Jun 2019	14,778	22.0	1.9	1.49	0.129	8.7% [4.2% - 13.2%]	82.8
Jul 2019	16,095	24.4	1.5	1.52	0.096	6.3% [2.8% - 9.8%]	83.4
Aug 2019	15,818	26.9	1.7	1.70	0.106	6.2% [3.3% - 9.1%]	86.4
Sep 2019	14,933	20.3	1.2	1.36	0.081	6.0% [2.5% - 9.4%]	80.6

ES.4 Ex-Ante Load Impacts

Ex-ante load impacts were developed separately for three TOU rates: E-TOU-A, E-TOU-B, and E-TOU-C3, and for five categories of TOU customers, as follows:

- *E-TOU-B and C3 incremental*. These are customers who are assumed to newly enroll in the E-TOU-B and C3 rates in future years. (E-TOU-A is closed to new enrollment during the forecast timeframe, so there are no incremental customers on that rate.)
- *E-TOU-A, B, and C3 embedded*. These are customers who were enrolled in E-TOU-A, B, and C3 as of the current year, and are assumed to remain on the rate in the future.

Figures ES.1 shows the yearly enrollments forecast for the month of August[4], for each customer group. The forecast assumes that E-TOU-A will be terminated in June 2020, with the assumption that the majority of its customers will transition to E-TOU-C3. Enrollments for the E-TOU-C3 incremental group dominates the forecast due to the defaulting process in the initial forecast years. Note that the E-TOU-C3 embedded customers reflect those enrolled in the rate via the Default Transition Phase I and those who chose to voluntarily enroll in the rate prior to 2020.

Figure ES.1: Forecast August Enrollments by Year and Customer Group

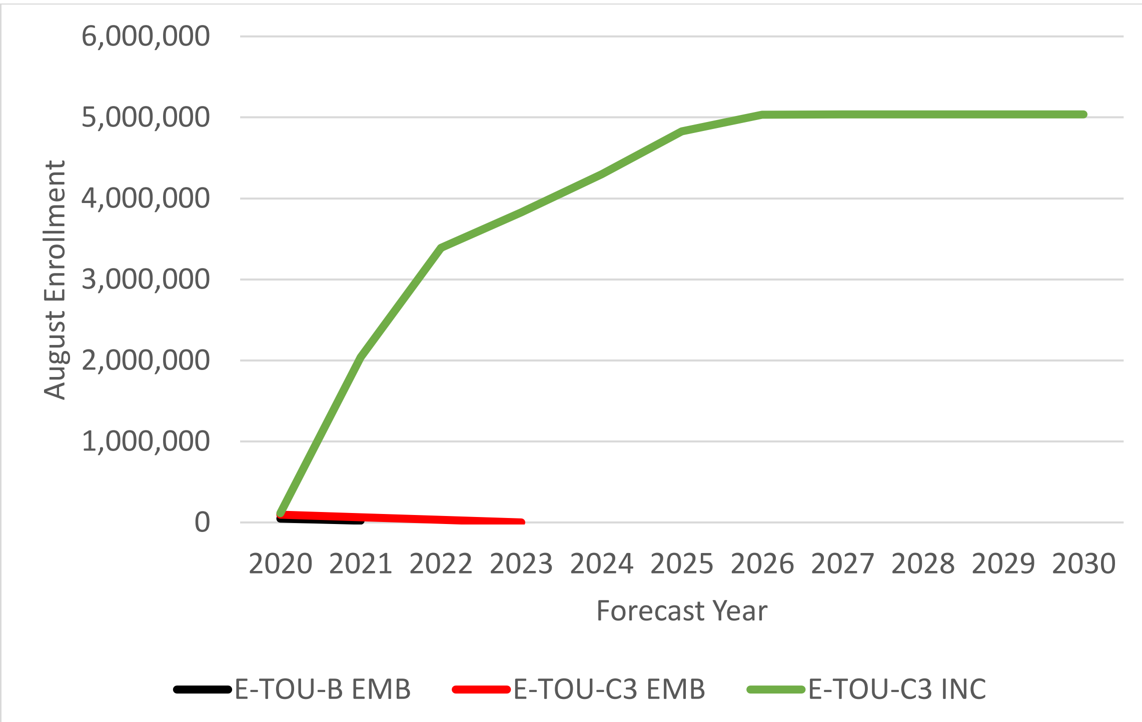
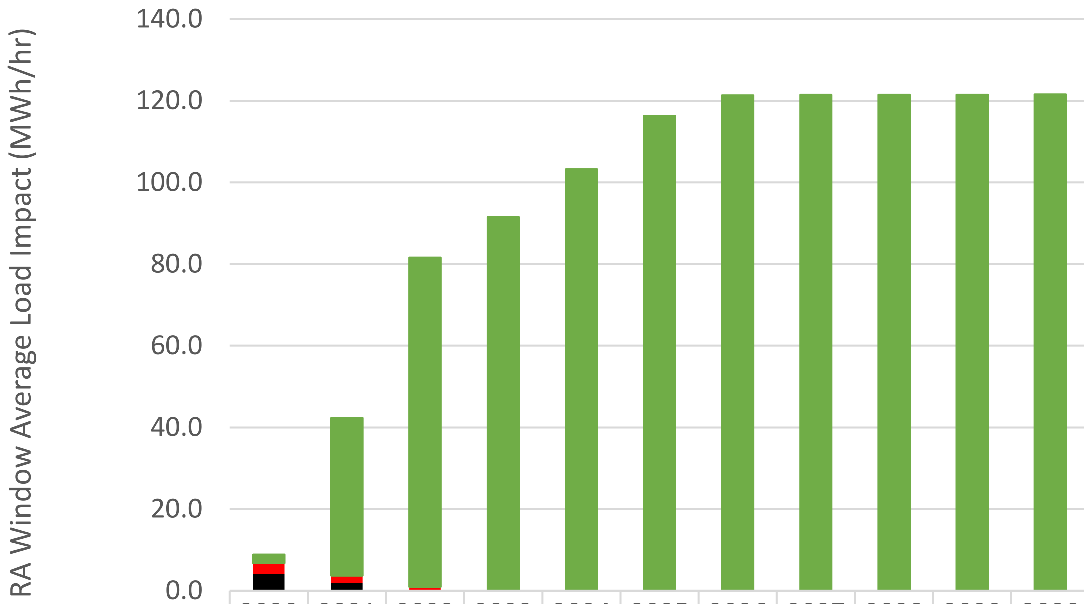


Figure ES.2 summarizes the forecast load impacts for each August during the forecast period. The values are the average load impacts during the Resource Adequacy window (4:00 to 9:00 p.m.) for the PG&E 1-in-2 weather conditions. The load impact pattern across years closely resembles the corresponding enrollment pattern, as shown in Figure ES.1.

[4] August is referenced here because it is likely to be the CAISO/PG&E peak period in a given year.

Figure ES.2: Average RA Window Load Impacts by Year, August PG&E 1-in-2 Peak Month



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
E-TOU-C3 INC	2.1	38.7	80.7	91.5	103.2	116.3	121.4	121.5	121.5	121.5	121.5
E-TOU-C3 EMB	2.7	1.8	0.9	0.0							
E-TOU-B EMB	4.0	1.9									

1. Introduction and Purpose of the Study

This report documents *ex-post* and *ex-ante* load impact evaluations for Pacific Gas and Electric Company's ("PG&E") residential time-of-use (TOU) rates for program year 2019, where the evaluations conform to the Load Impact Protocols adopted by the CPUC in D-08-04-050. PG&E's residential TOU rates include E-TOU-A, E-TOU-B, and E-TOU-C3.[5]

E-TOU-C3 was made available to customers in April 2018 and currently consists of customers who were selected for TOU Transition Phase I (referred to as "the Default pilot") and continued with the transition in April 2018; and residential customers who voluntarily opted into the rate. The *ex-post* analysis in this evaluation focuses on the customers who voluntarily opted into the rate; load impacts for the TOU Transition Phase I pilot are estimated in a separate study.[6] However, the *ex-ante* forecast in this study includes both voluntary and Default E-TOU-C3 customers.

The primary goals of the evaluation are the following:

1. Estimate *ex-post* load impacts for each rate for program year 2019, and
2. Develop *ex-ante* load impact forecasts for the rates for 2020 through 2030.

The report is organized as follows. Section 2 contains descriptions of the TOU rates; Section 3 describes the methods used to estimate *ex-post* load impacts and forecast *ex-ante* load impacts; Section 4 contains the *ex-post* load impact results, including analyses of load impacts by climate region and whether the customer was expected to be a structural benefiter on the TOU rate. Section 5 describes the estimates from extending the PY2018 *ex-post* analyses. Section 6 contains the *ex-ante* load impact forecasts. Section 7 provides a series of comparisons of *ex-post* and *ex-ante* results, for the current and previous evaluations.

2. Description of Time-of-Use Rates

In 2019, PG&E offered three options for customers who wished to enroll in a TOU rate plan. E-TOU-A and E-TOU-B were introduced for Residential customers in 2016 while E-TOU-C3 became available in 2018. E-TOU-A was closed to new enrollment at the end of 2019 and is scheduled for termination in 2020. E-TOU-B will close to new enrollment at the end of April 2020 but will remain available to current enrollees until the end of 2025.

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

[5] Previous evaluations included E-6 and E-7. E-7 is terminated and E-6 is closed to new enrollment and scheduled to be terminated at the end of 2020.

[6] However, Default Pilot TOU load impacts from the second summer (June through September 2019) are presented in this report (in Section 4.6).

transition Default Pilot was limited to a subset of the total eligible population[7], 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.

All three E-TOU rates have 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 do not. The peak periods are defined as follows: E-TOU-A is 3 p.m. to 8 p.m. on non-holiday weekdays; E-TOU-B is 4 p.m. to 9 p.m. on non-holiday weekdays; and E-TOU-C3 is 4 p.m. to 9 p.m. on all days. E-TOU-A and E-TOU-C3 include a tiered rate structure in which customers receive a $/kWh credit for usage up to the amount of the tariff-defined baseline quantities; the latter varies geographically by Baseline Territory. This feature makes those two rates more appealing to low-use customers, while E-TOU-B is likely to appeal to higher-use customers due to the absence of the tiered structure.

Many customers who have installed solar photovoltaic systems are also enrolled in a TOU rate and net metering (NEM). Those customers are excluded from this study, which includes only non-NEM customers.

The primary *ex-post* analyses contained in this study examine E-1 customers who opted into E-TOU-A, E-TOU-B, or E-TOU-C3 during the 2019 program year (October 2018 through September 2019). In addition, we estimated some extensions of the analysis in the PY2018 load impact evaluation, which estimate the persistence of the load impacts for customers who migrated from E-1 to E-TOU-A, E-TOU-B, or E-TOU-C3.

3. Study Methodology

This section discusses project objectives and technical issues that are addressed in this study, and our approach to addressing those issues. We begin by discussing the *ex-post* load impact objectives and estimation methods, then turn to the *ex-ante* forecasts.

3.1 Ex-Post Load Impact Evaluation

3.1.1 Project objectives

For non-event-based programs such as the TOU rates, the load impact Protocols call for estimating hourly load impacts for each required day type, including the average weekday in each month and monthly system peak days. The relatively large number of TOU customers who are net metered are out of scope of this evaluation and hence excluded from this evaluation.[8] The *ex-post* study estimates *incremental* TOU load

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[7] 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.

[8] NEM TOU customers were examined in a separate analysis during PY2016. PG&E does not wish to extend the study of those customers to this year because the estimation of those load impacts is

impacts, which are the TOU load impacts attributable to newly enrolled customers. *Embedded* TOU load impacts (those attributable to existing TOU customers) are included in the *ex-ante* forecast, but are not included in the *ex-post* study. For these customers, the current-year load profiles reflect TOU demand response. However, that response was also present prior to the current program year, making it difficult to estimate the impacts from joining a TOU rate. Thus, embedded load impacts relate primarily to the *ex-ante* load impact forecasts.

As was the case during prior program years, PG&E is interested in differentiating load impacts for customers who do and do not receive a structural benefit from switching to the TOU rate. That is, customers with relatively less on-peak usage can experience a bill reduction on TOU without modifying their load profile. Such customers may be referred to as "structural benefiters." PG&E provided customer-specific indicators of structural benefiters, which we use to provide summaries of load impacts by structural benefiter status.

The primary *ex-post* analyses is conducted for three groups of customers, defined as those who changed rates from E-1 to E-TOU-A, E-TOU-B, and E-TOU-C3 with the latter group consisting of only customers who voluntarily joined the rate (and excluding customers who were enrolled via Default Transition Phase I).

In addition to the analyses described above, we extend our analyses of incremental E-TOU-A, E-TOU-B, and E-TOUC3 load impacts from the 2018 program year. These analyses use the same control-group matches employed in the prior evaluation (subject to the match remaining valid based on the customer's current rate and NEM status). The resulting estimates may provide useful information about the persistence of TOU load impacts.

3.1.2 Evaluation Methods

Estimating the load impacts of the TOU rates, as in all evaluations, requires a method for estimating what participating customers' usage would have been in the absence of the program; that is, what their usage pattern would have been had they not experienced the static time-varying TOU rates. Since the rates do not vary across days within a season, the logical sources of reference loads include: 1) contemporaneous control group customers, resulting in a treatment/control evaluation approach, or 2) pre-treatment usage data of the TOU participants, resulting in a before/after evaluation approach. Where feasible, the two approaches may be combined in a difference-in-differences approach, as in the prior evaluations. Load impacts are calculated as the difference between the counter-factual reference loads and the observed loads of the enrolled customers.

complicated by data limitations (*i.e.*, the absence of hourly loads generated by the customer, distinct from their premise usage).

Control group selection

For the newly enrolled former E-1 customers in E-TOU-A, E-TOU-B, and E-TOU-C3, the control group selection approach involves a two-stage matching process to deal with the very large number of potential control group customers who remain on E-1 throughout the analysis period. In the first stage, we request monthly billing data for October 2017 through September 2018 for the TOU and potential control group customers. During this time period, all customers are served on E-1, thus excluding treatment effects from the matching process. We then apply Euclidean distance matching using pre-treatment monthly billing data summary variables (average daily usage in summer and winter) to reduce the large number of available E-1 customers to a reduced set of preliminary matches for each TOU customer.[9]

In the second stage, we collapse pre-treatment period interval load data to pre-defined 24-hour profiles[10], for all TOU customers and the preliminary matched E-1 customers. We apply Euclidean distance minimization to load profiles for the pre-enrollment period, and select control group matches (with replacement) for each TOU customer. In addition to the matching on seasonal profiles, the matching process is conducted by LCA and CARE status, ensuring matches by those two characteristics. Separate matches are selected by season. Finally, we request hourly load data for the full analysis period for the TOU customers and selected E-1 control group customers. These data are used in the *ex-post* load impact analysis, and in the development of reference loads for the *ex-ante* analysis. A summary of the matches is contained in Appendix I.

Once the matched control-group customers are selected and load data obtained, we use regression analysis to compare treatment and control group loads in the post-enrollment period, while controlling for differences in the pre-enrollment period (*i.e.*, difference-in-differences), as described below.

Load impact estimation

The presence of matched control group customers means that the estimation equations for the incremental *ex-post* evaluation may be quite simple, essentially a formal regression analysis to compare the loads of treatment and control group customers on the day types that are required for load impact evaluations of non-event-based programs like TOU rates (average weekdays and system peak days by month). Since the pre-enrollment data that are used in the control group matching process are available, we include data for each non-holiday weekday in each month for the pre-enrollment period (for the average weekday analysis), resulting in difference-in-differences models.

[9] We then select the four nearest neighbors for each treatment customer for inclusion in the Stage 2 match.

[10] CA Energy Consulting selected the days to be included in the seasonal profiles from "core" months (June through August for summer; December through February for winter). Within each season, three profiles were developed based on daily average temperatures, weighted across the weather stations associated with the segment. The top 10 percent of days was the extreme (*i.e.*, hot in summer) profile, the middle 50 percent of days was the typical profile, and all weekend days constituted the third profile.

Separate models are estimated by hour, month, CARE status, and LCA, where the customer-level fixed-effects models are of the following form:[11]

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

The variables and coefficients in the equation are described in the following table:

Symbol	Description
$kW_{c,d}$	Load in a particular hour for customer *c* on day *d*
TOU_c	Variable indicating whether customer *c* is a TOU (1) or Control (0) customer
$Post_d$	Variable indicating that day *d* is in the post-enrollment period
$Mean17_{c,d}$	Average temperature during the first 17 hours of day *d* at the weather station associated with customer *c*
α	Estimated constant coefficient
β_{TOU}	Estimate of TOU load impact
β_{Mean17}	Estimate of effect of weather on customer usage
C_c	Customer fixed effects
D_d	Date fixed effects
$\varepsilon_{c,d}$	Error term

3.2 Forecasting Ex-Ante Load Impacts

3.2.1 Objectives

The objectives of the *ex-ante* portion of the evaluation involve developing eleven-year forecasts of estimated program load impacts based on the *ex-post* findings of per-customer load impacts and PG&E's enrollment projections. The load impacts are to be provided for several customer sub-groups, day types, and weather scenarios, including the following:

- An average weekday in each month under each of the four weather scenarios (CAISO 1-in-2 and 1-in-10 weather years and PG&E 1-in-2 and 1-in-10 weather years);
- The monthly system peak day in each month under the four weather scenarios.

3.2.2 *Ex-ante* evaluation approach

To develop *ex-ante* load impacts for the TOU rates, we first develop regression equations for the purposes of simulating reference loads using the temperature conditions contained in the scenarios required by the Protocols. The models use hourly load data from the pre-treatment period averaged across "cells" (*e.g.*, for the average

[11] Note that the customer and date fixed effects preclude the need to include stand-alone TOU_c and $Post_d$ 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.

residential customer in each TOU rate and LCA). The reference load model explains hourly usage as a function of weather conditions, day type, time of day, and month.

Per-customer *reference loads* are produced from the estimated equations by simulating (*i.e*., predicting) loads using the appropriate day type and weather conditions for each required month. Per-customer *load impacts* are based on the current *ex-post* load impact evaluations. The *ex-ante* load impacts assume that hourly load impacts are a constant percentage of the reference load, where those percentages are estimated from a model that pools customers across LCAs within TOU rate.[12]

Uncertainty-adjusted load impacts are based on the standard errors from these models. Scenario-specific percent load impacts will be developed from 10th, 30th, 50th, 70th, and 90th percentile load changes estimated for the relevant program year.

As in all recent load impact evaluations, we present results of analyses of the relationship between current *ex-post* and *ex-ante* load impacts, focusing on key factors causing differences between them (*e.g.*, differences between observed temperatures in 2019 and the temperatures in the various weather scenarios). We will also compare current and previous *ex-post* load impacts, and current and previous *ex-ante* load impacts.

The *ex-ante* forecasts of E-TOU-C3 customers differs somewhat from the methods described above. Because the forecast customers largely consist of customers defaulted onto the rate (rather then voluntarily joining it), the reference loads and load impacts are derived from our separate evaluation of the Default TOU pilot program. Specifically, we adapt the most recent load impacts from the study, which correspond to the first winter on the rate (October 2018 through May 2019) and the second summer on the rate (June through September 2019).[13] Because the Default TOU pilot employed segments based on climate region, CARE status, and presence in a CCA, we needed to reconfigure the loads and load impacts to represent the Local Capacity Areas required for this evaluation. This involved taking weighted averages of segment-level outcomes using the shares of customers in each segment and the population weights associated with each pilot segment.

In addition, the incremental E-TOU-C3 forecast consists of several types of customers. The largest group contains customers defaulted onto the rate. In addition, increases in E-TOU-C3 enrollments correspond to the termination of E-TOU-A in June 2020; the closure of E-TOU-B to new enrollment in April 2020; and the termination of E-6

[12] The exception is the Default E-TOU-C3 customers, for whom we develop LCA-specific load impacts. Large sample sizes for this customer group allowed us to develop robust load impact estimates at a more granular level than we could for the voluntary TOU rates.

[13] Note that the load impacts in the second summer (June through September 2019) were significantly lower than those of the first summer, so using the second-summer load impacts as the basis of the *ex-ante* forecast is a conservative assumption.

December 2020. The E-TOU-C3 forecast is formed as the weighted average of those component parts, assuming attrition in the migrated customers over time.[14]

4. Incremental *Ex-Post* Load Impact Study Findings

This section reports *ex-post* peak load impact findings for the customers who migrated from the standard E-1 residential rate to E-TOU-A, E-TOU-B, or E-TOU-C3. Relevant subsections report reference loads and load impacts for the average weekday by month, by LCA, by climate region, and by CARE status. Typical hourly load profiles are also shown.

Many of the tables include the number of enrolled customers. Note that this is often much higher than the number of customers included in the regression model, which is constrained by starting service on or after October 1, 2018 and having migrated from E-1. In some cases, regression results are based on a very low number of customers, which is reflected in a broad confidence interval around the percentage load impact.

4.1 Peak-period load impacts by month

Table 4.1 shows the estimated peak-period load impacts for the E-1 to E-TOU-A customers. Results are shown from October 2018 through September 2019, with each row representing the month's average weekday. Non-NEM enrollment reached approximately 33,000 during the program year. Percentage load impacts ranged from 0.9 percent in October to 8.9 percent in January. Note that the regression sample is smallest in these early months, as the models include only customers enrolled on or after October 1, 2018. (Enrollments reflect total non-NEM enrollment rather than the regression sample size.) The results get more robust as the program year proceeds. Some of the estimated load impacts (October, May, and June) are not statistically significantly different from zero.

[14] We assume that E-6 customer load profiles and load impacts match those of the defaulted E-TOU-C3 customers. Our examination of customer load levels from the most recent E-6 evaluation (from the *ex-ante* forecast following PY2017) indicated that they were sufficiently similar to those of the defaulted E-TOU-C3 customers.

Table 4.1: E-1 to E-TOU-A Peak Load Reductions – *Average Weekday by Month*[15]

Month	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
		Peak Ref. Load (MW)	Peak Load Impact (MW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
Oct 2018	25,324	11.8	0.1	0.46	0.004	0.9% [-2.0% - 3.7%]	69.0
Nov 2018	23,848	14.2	0.5	0.59	0.023	3.8% [1.3% - 6.4%]	59.5
Dec 2018	24,226	17.5	1.2	0.72	0.048	6.6% [3.9% - 9.3%]	54.5
Jan 2019	29,077	20.0	1.8	0.69	0.061	8.9% [6.4% - 11.4%]	56.0
Feb 2019	25,686	18.1	0.8	0.71	0.029	4.2% [2.2% - 6.1%]	51.7
Mar 2019	29,428	16.7	0.8	0.57	0.026	4.5% [2.8% - 6.2%]	58.6
Apr 2019	30,297	15.5	0.9	0.51	0.030	5.9% [4.3% - 7.4%]	67.3
May 2019	31,095	14.7	0.2	0.47	0.007	1.4% [-0.7% - 3.5%]	66.3
Jun 2019	31,473	18.5	0.2	0.59	0.007	1.3% [-0.9% - 3.4%]	81.8
Jul 2019	33,120	20.1	0.8	0.61	0.024	3.9% [1.4% - 6.4%]	81.6
Aug 2019	30,675	20.6	0.7	0.67	0.024	3.6% [1.6% - 5.7%]	85.1
Sep 2019	28,308	16.2	0.4	0.57	0.016	2.8% [1.0% - 4.6%]	80.8

Table 4.2 shows the corresponding results for the E-1 to E-TOU-B customers. Non-NEM enrollment in E-TOU-B reached approximately 34,000 during the program year. As expected given the rate design (which benefits higher-use customers due to the absence of the tier structure), the per-customer reference loads for E-TOU-B customers are considerably higher than those of the E-TOU-A customers. In addition, both the level and percentage of the E-TOU-B per-customer load impacts is higher than those of E-TOU-A in most months.

[15] The brackets accompanying the percentage load impacts represent the 10th and 90th percentile uncertainty adjusted load impacts.

Table 4.2: E-1 to E-TOU-B Peak Load Reductions – *Average Weekday by Month*

Month	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
		Peak Ref. Load (MW)	Peak Load Impact (MW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
Oct 2018	26,112	47.3	1.8	1.81	0.070	3.9% [-0.9% - 8.7%]	68.2
Nov 2018	24,119	49.2	4.4	2.04	0.182	8.9% [4.0% - 13.8%]	57.6
Dec 2018	24,909	54.7	3.2	2.19	0.127	5.8% [2.4% - 9.3%]	52.5
Jan 2019	29,859	59.1	1.7	1.98	0.058	2.9% [0.2% - 5.7%]	54.1
Feb 2019	26,221	51.5	0.1	1.97	0.002	0.1% [-2.5% - 2.7%]	50.0
Mar 2019	30,075	50.8	1.6	1.69	0.053	3.1% [0.7% - 5.5%]	57.3
Apr 2019	31,120	52.7	3.6	1.69	0.117	6.9% [4.4% - 9.4%]	66.5
May 2019	31,933	51.8	2.4	1.62	0.074	4.6% [2.2% - 7.0%]	65.8
Jun 2019	32,341	70.6	3.6	2.18	0.112	5.1% [3.5% - 6.8%]	82.1
Jul 2019	34,087	76.1	3.5	2.23	0.103	4.6% [3.0% - 6.2%]	82.6
Aug 2019	32,228	80.0	5.3	2.48	0.164	6.6% [5.2% - 8.0%]	85.3
Sep 2019	31,030	64.3	3.1	2.07	0.101	4.9% [3.4% - 6.4%]	80.3

Table 4.3 shows the monthly peak-period load impacts for the customers who voluntarily joined E-TOU-C3 from E-1. Load impacts varied considerably across months, from -0.013 in May to 0.231 in November. Notice the broad confidence interval in the percentage load impacts, which likely reflects uncertainty due to small sample sizes.

Table 4.3: E-1 to Voluntary E-TOU-C3 Peak Load Reductions – *Average Weekday by Month*

Month	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
		Peak Ref. Load (MW)	Peak Load Impact (MW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
Oct 2018	3,233	[redacted]					69.4
Nov 2018	3,757	5.7	0.9	1.53	0.231	15.1% [5.4% - 24.8%]	57.7
Dec 2018	5,284	7.9	0.5	1.50	0.095	6.3% [0.8% - 11.9%]	52.5
Jan 2019	7,926	11.1	0.9	1.40	0.118	8.4% [2.8% - 14%]	54.2
Feb 2019	8,304	11.4	0.6	1.37	0.076	5.5% [1.9% - 9.1%]	50.4
Mar 2019	10,667	12.3	0.6	1.16	0.054	4.7% [1.2% - 8.1%]	57.6
Apr 2019	12,403	13.0	(0.0)	1.05	0.000	0.0% [-5.9% - 5.9%]	66.8
May 2019	13,937	13.9	(0.2)	1.00	-0.013	-1.3% [-5.4% - 2.8%]	66.2
Jun 2019	14,778	22.0	1.9	1.49	0.129	8.7% [4.2% - 13.2%]	82.8
Jul 2019	16,095	24.4	1.5	1.52	0.096	6.3% [2.8% - 9.8%]	83.4
Aug 2019	15,818	26.9	1.7	1.70	0.106	6.2% [3.3% - 9.1%]	86.4
Sep 2019	14,933	20.3	1.2	1.36	0.081	6.0% [2.5% - 9.4%]	80.6

4.2 Seasonal peak load impacts by LCA and Climate Region

Tables 4.4 and 4.5 show E-TOU-A peak-period load impacts for the average summer weekday, by LCA and climate region, respectively.[16] Percentage peak load impacts vary considerably across LCAs, averaging 2.9 percent. Many of the estimated load impacts are not statistically significantly different from zero (Greater Fresno, Kern, Northern Coast, Other, and Stockton). Most of the customers are in the Greater Bay Area, which explains the comparatively small confidence interval around the estimated load impact. The results by climate region (in Table 4.5) reflect the expected relationship between climate region and average customer usage, with the highest-use customers in the hot region. While the level of load impacts is highest in the hot climate region, the

[16] Climate regions are defined by the customer's Baseline Territory. The "hot" region includes the P, R, S, and W territories; the "moderate" region includes the Q, X, and Y territories; and the "cool" region includes the T, V, and Z territories.

percentage load impact is the lowest (and the estimate is not statistically significantly different from zero).

Table 4.4: E-1 to E-TOU-A Peak Load Reductions by LCA – Average *Summer* Weekday

LCA	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
		Peak Ref. Load (MW)	Peak Load Impact (MW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
Greater Bay Area	22,492	10.7	0.3	0.48	0.013	2.7% [1.1% - 4.3%]	77.7
Greater Fresno	1,000	[redacted]					94.6
Humboldt	524	0.3	0.0	0.56	0.081	14.6% [3.4% - 25.9%]	67.9
Kern	244	[redacted]					95.3
Northern Coast	2,531	1.6	0.1	0.62	0.025	4.0% [-3.9% - 11.9%]	83.1
Other	2,218	2.1	0.1	0.96	0.059	6.1% [-0.1% - 12.3%]	87.4
Sierra	1,334	1.4	0.1	1.09	0.075	6.9% [0.2% - 13.6%]	88.7
Stockton	553	[redacted]					89.4
All	30,894	18.8	0.6	0.61	0.018	2.9% [0.8% - 5.1%]	82.3

Table 4.5: E-1 to E-TOU-A Peak Load Reductions by Climate Region – Average *Summer* Weekday

Climate Region	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
		Peak Ref. Load (MW)	Peak Load Impact (MW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
Hot	4,641	5.7	0.2	1.23	0.035	2.8% [-2.2% - 7.8%]	90.8
Moderate	15,931	9.2	0.4	0.58	0.027	4.6% [2.6% - 6.6%]	81.1
Cool	10,322	3.8	0.1	0.37	0.015	3.9% [1.4% - 6.5%]	70.5

Tables 4.6 and 4.7 show comparable results for the E-1 to E-TOU-B group. For this group, percentage load impacts average 5.3 percent. The load impact is not statistically significantly different from zero in five of the LCAs. As Table 4.7 shows, the E-TOU-B customers have the higher reference load and load impact levels as the climate region gets hotter, while the percentage load impact in the hot climate region is comparable to that of the moderate climate region.

Table 4.6: E-1 to E-TOU-B Peak Load Reductions by LCA – Average *Summer* Weekday

		Aggregate		Per-Customer			
LCA	Enrolled	Peak Ref. Load (MW)	Peak Load Impact (MW)	Peak Ref. Load (kW)	Peak Load Impact (kW)	% Peak Load Impact	Ave. Peak Temp.
Greater Bay Area	17,869	32.2	1.7	1.80	0.096	5.4% [3.6% - 7.1%]	76.7
Greater Fresno	2,159	7.6	0.5	3.53	0.225	6.4% [1.2% - 11.6%]	93.4
Humboldt	1,265	2.3	0.1	1.82	0.109	6.0% [-7.1% - 19.1%]	71.4
Kern	622	[redacted]					94.9
Northern Coast	3,228	6.3	0.2	1.96	0.052	2.7% [-2.0% - 7.3%]	80.0
Other	3,698	10.3	0.5	2.79	0.140	5.0% [-0.1% - 10.1%]	88.3
Sierra	2,549	8.4	0.4	3.31	0.151	4.6% [-1.0% - 10.1%]	87.9
Stockton	1,034	[redacted]					88.2
All	32,422	72.7	3.9	2.24	0.120	5.3% [3.8% - 6.9%]	82.6

Table 4.7: E-1 to E-TOU-B Peak Load Reductions by Climate Region – Average *Summer* Weekday

		Aggregate		Per-Customer			
Climate Region	Enrolled	Peak Ref. Load (MW)	Peak Load Impact (MW)	Peak Ref. Load (kW)	Peak Load Impact (kW)	% Peak Load Impact	Ave. Peak Temp.
Hot	9,529	31.8	1.8	3.33	0.186	5.6% [2.9% - 8.2%]	89.8
Moderate	13,988	30.3	1.6	2.17	0.118	5.4% [3.5% - 7.3%]	79.9
Cool	8,905	11.0	0.2	1.24	0.028	2.2% [-1.5% - 6.0%]	68.5

Tables 4.8 and 4.9 show voluntary E-TOU-C3 load impacts by LCA. Persistent small sample sizes lead to large confidence intervals around the estimated load impact in most of the LCAs, with an average load impact of 6.8 percent. Table 4.9 shows the highest load impacts in the moderate climate region, whereas the estimate is not statistically significant in the other two climate regions.

Table 4.8: E-1 to Voluntary E-TOU-C3 Peak Load Reductions by LCA – Average *Summer* Weekday

LCA	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
		Peak Ref. Load (MW)	Peak Load Impact (MW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
Greater Bay Area	8,003	9.5	0.5	1.19	0.068	5.7% [1.7% - 9.7%]	76.8
Greater Fresno	1,402	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93.8
Humboldt	313	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65.1
Kern	515	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89.7
Northern Coast	1,403	1.7	0.1	1.22	0.057	4.7% [-2.9% - 12.2%]	81.1
Other	2,026	3.8	(0.1)	1.87	-0.027	-1.5% [-11.5% - 8.5%]	87.7
Sierra	1,204	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87.2
Stockton	540	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87.8
All	15,406	23.4	1.6	1.52	0.103	6.8% [3.2% - 10.3%]	83.3

Table 4.9: E-1 to Voluntary E-TOU-C3 Peak Load Reductions by Climate Region – Average *Summer* Weekday

Climate Region	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
		Peak Ref. Load (MW)	Peak Load Impact (MW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
Hot	5,309	11.8	0.5	2.22	0.088	3.9% [-2.3% - 10.2%]	89.3
Moderate	5,966	8.2	0.8	1.38	0.126	9.2% [5.0% - 13.4%]	79.7
Cool	4,131	3.3	(0.1)	0.81	-0.036	-4.4% [-11.5% - 2.7%]	69.2

4.3 Peak load impacts by CARE status

Tables 4.10 through 4.12 show average summer peak-period load reductions by CARE status for the E-TOU-A, E-TOU-B, and voluntary E-TOU-C3 customers, respectively. In each case, non-CARE customers have higher load impacts. Notice that the CARE customers have higher average peak temperatures in each table, which is likely explained by where CARE customers tend to live compared to non-CARE customers. To some extent, this difference is reflected in the average reference loads (particularly in Table 4.10).

Table 4.10: Peak Load Reductions by CARE Status – *E-1 to E-TOU-A*

Season	CARE Status	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MW)	Peak Load Impact (MW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
Summer	Non-CARE	26,876	15.5	0.5	0.58	0.020	3.5% [1.1%-5.9%]	81.5
	CARE	4,019	3.3	0.0	0.83	0.003	0.4% [-4.1%-4.9%]	85.9

Table 4.11: Peak Load Reductions by CARE Status – *E-1 to E-TOU-B*

Season	CARE Status	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MW)	Peak Load Impact (MW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
Summer	Non-CARE	26,495	59.6	3.3	2.25	0.126	5.6% [3.8%-7.4%]	81.7
	CARE	5,927	13.1	0.6	2.21	0.093	4.2% [2.0%-6.4%]	86.5

Table 4.12: Peak Load Reductions by CARE Status – *E-1 to Voluntary E-TOU-C3*

Season	CARE Status	Enrolled	Aggregate		Per-Customer		% Peak Load Impact	Ave. Peak Temp.
			Peak Ref. Load (MW)	Peak Load Impact (MW)	Peak Ref. Load (kW)	Peak Load Impact (kW)		
Summer	Non-CARE	12,512	18.9	1.4	1.51	0.115	7.6% [3.3%-11.9%]	82.3
	CARE	2,894	4.5	0.1	1.55	0.050	3.2% [-0.1% - 6.5%]	87.5

4.4 Hourly Loads and Load Impacts

This subsection illustrates the hourly load and load impact profiles for the average weekdays in January and August 2019. Figures 4.1 and 4.2 show aggregate hourly observed and estimated reference loads, along with hourly estimated load impacts (right axis) for the E-1 to E-TOU-A customers in August 2019 and January 2019, respectively. Figures 4.3 and 4.4 show the same information for the E-TOU-B customers;

and Figures 4.5 and 4.6 show the same information for the voluntary E-TOU-C3 customers. The peak pricing periods are highlighted in all figures.

Figure 4.1: Per-customer Hourly Loads and Load Impacts – E-1 to E-TOU-A (*Average Weekday, August 2019*)

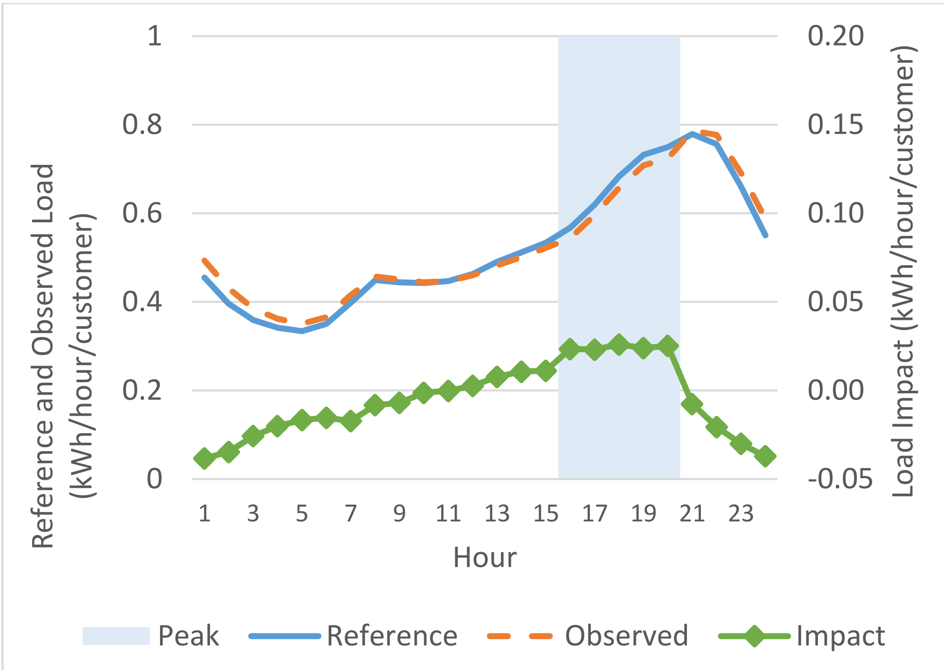


Figure 4.2: Aggregate Hourly Loads and Load Impacts (MW) – E-1 to E-TOU-A (*Average Weekday, January 2019*)

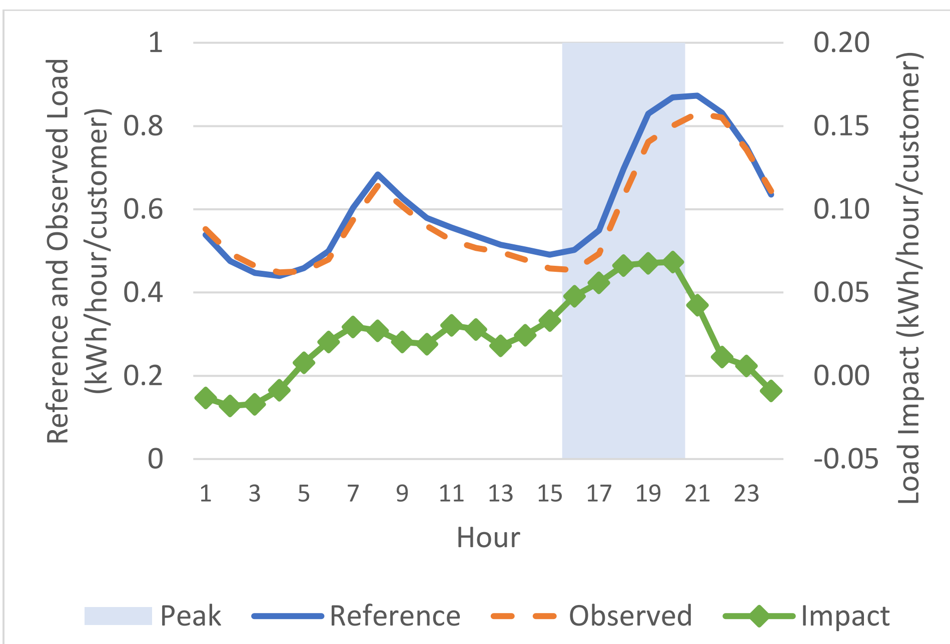


Figure 4.3: Aggregate Hourly Loads and Load Impacts (MW) – E-1 to E-TOU-B
(*Average Weekday, August 2019*)

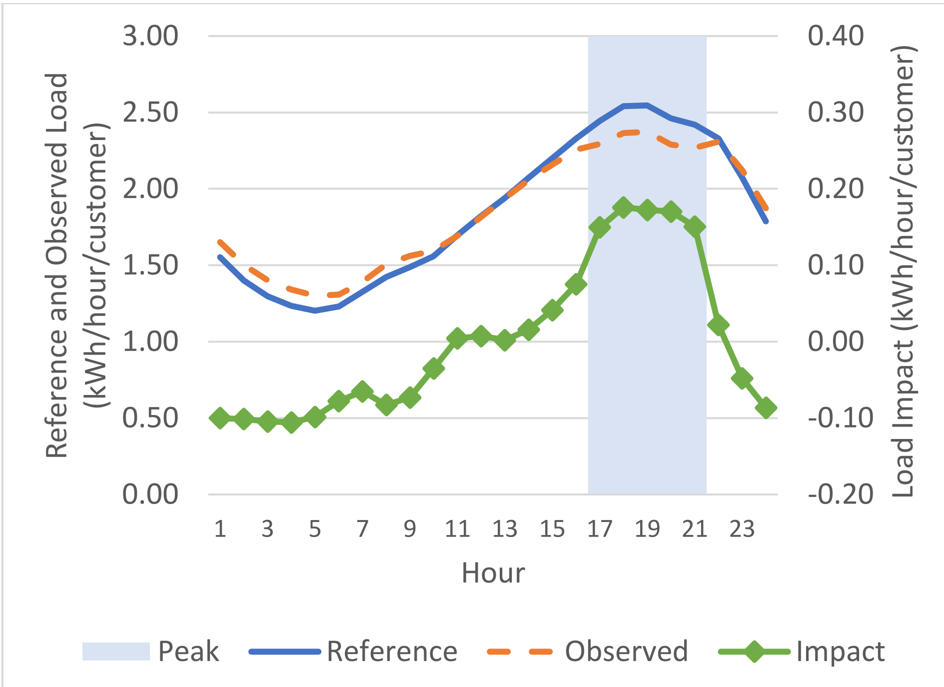


Figure 4.4: Aggregate Hourly Loads and Load Impacts (MW) – E-1 to E-TOU-B (*Average Weekday, January 2019*)

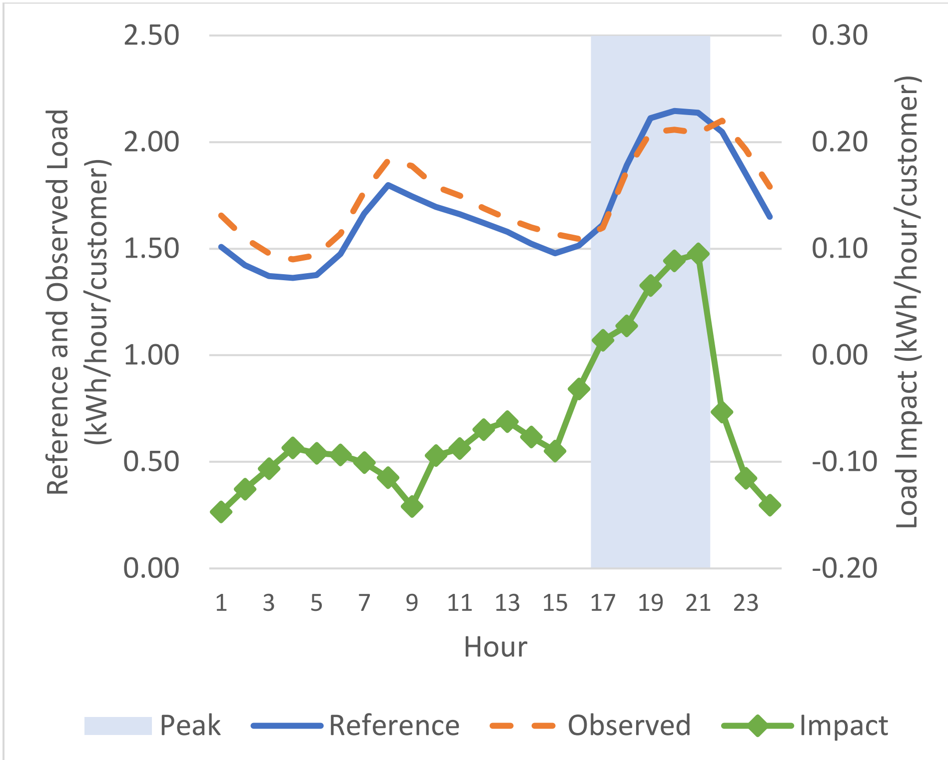


Figure 4.5: Aggregate Hourly Loads and Load Impacts (MW) – E-1 to Voluntary E-TOU-C3 (*Average Weekday, August 2019*)

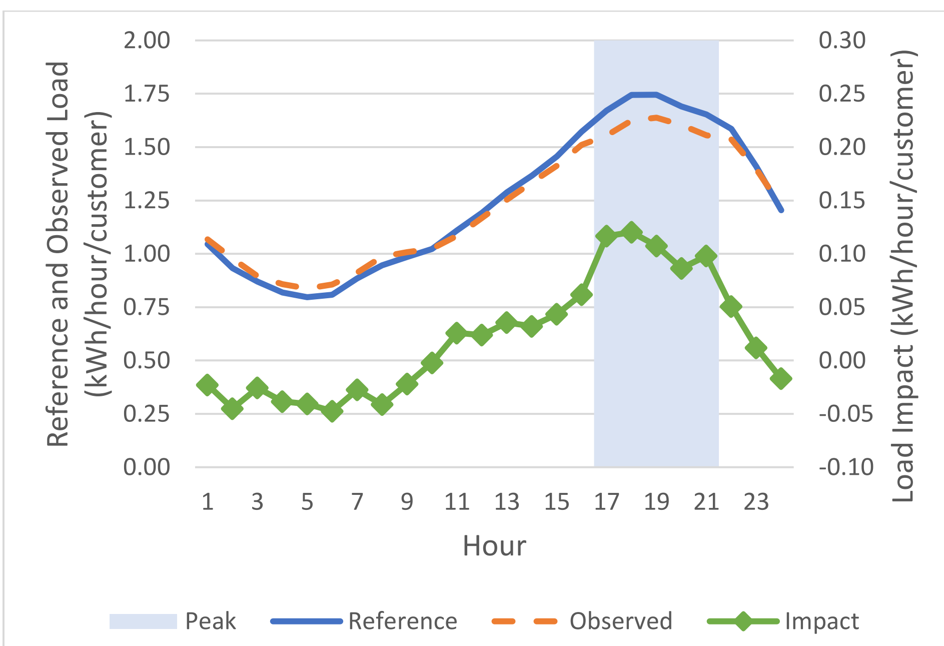
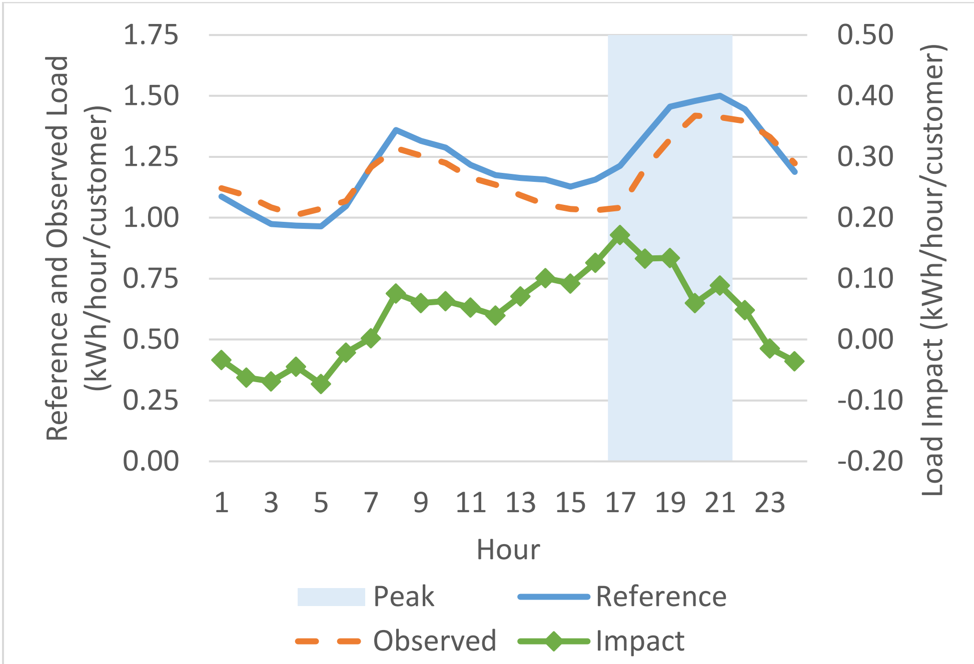


Figure 4.6: Aggregate Hourly Loads and Load Impacts (MW) – E-1 to Voluntary E-TOU-C3 (*Average Weekday, January 2019*)



4.5 Load Impacts for Structural Benefiters

PG&E provided a variable indicating whether each E-TOU-A, E-TOU-B, and E-TOU-C3 customer was expected to be a "structural benefiter", which is a customer who experiences a bill reduction after switching to a TOU rate without changing their behavior. For example, a customer with a relatively flat load profile (and therefore a lower than average proportion of usage in the peak pricing period) may save money on a TOU rate without taking any action.

The variable provided by PG&E was based on an analysis of customer loads when the customer was on E-1, comparing their bill to what it would have been on the E-TOU rate with the same usage pattern and level.[17]

The share of structural benefiters was quite different by rate, with 85 percent of E-TOU-A customers, 91 percent of E-TOU-B customers, and 80 percent of voluntary E-TOU-C3 customers obtaining that status.[18] One explanation for the high share of E-TOU-B benefiters is that it provides a way for high-use customers to avoid tiered pricing (which is present in E-1 and E-TOU-A and E-TOU-C3 but not E-TOU-B). This theory is supported by the fact that E-TOU-B benefiters use 28 percent more energy during

[17] Note that data limitations prevented the classification of all customers included in our *ex-post* study. Approximately 20 percent of customers in our *ex-post* analysis are not classified.
[18] The shares exclude customers with missing rate comparison information.

summer months than E-TOU-B non-benefiters. Conversely, E-TOU-A benefiters use 28 percent less than E-TOU-A non-benefiters during summer months.

To explore whether structural benefiters respond differently to TOU rates, we estimated models similar to those described in Section 3.1.2, separating load impact estimates by benefiter status.

Table 4.13 summarizes the summer reference loads and estimated load impacts by rate for each of the TOU rates. We have the following observations:

- For E-TOU-B, structural benefiters have higher reference loads than non-benefiters. The opposite is true for E-TOU-A and E-TOU-C3. As described above, this is attributable to the absence of the tiered rate structure in E-TOU-B.
- E-TOU-A non-benefiters exhibited significant usage increases in the treatment year, which may be due to omitted variables rather than a TOU effect.
- E-TOU-B non-benefiters are somewhat more responsive than benefiters during peak hours, while the reverse is true for voluntary E-TOU-C3 customers.

Table 4.13: Average Summer Peak-Hour and Daily Load Impacts by Structural Benefiter Status (kWh/hour/customer)

Rate	Hours	Reference Load (kWh/hr/cust)		Load Impact (kWh/hr/cust)		% Load Impact	
		Non-benefiter	Benefiter	Non-benefiter	Benefiter	Non-benefiter	Benefiter
E-TOU-A	Peak	0.86	0.57	-0.135	0.036	-15.6%	6.3%
	All	0.61	0.44	-0.126	0.009	-20.6%	2.0%
E-TOU-B	Peak	1.97	2.17	0.093	0.087	4.7%	4.0%
	All	1.30	1.67	0.024	-0.052	1.9%	-3.1%
E-TOU-C3 Voluntary	Peak	1.58	1.32	0.005	0.040	0.3%	3.0%
	All	1.03	1.03	-0.033	-0.028	-3.2%	-2.7%

4.6 Summer 2019 Default TOU Pilot Load Impacts

The first-year load impacts (from June 2018 through May 2019) of customers in PG&E's Default TOU Pilot program are documented in a separate report.[19] Load impacts during the second summer (June through September 2019) were estimated as part of this study as an input to the *ex-ante* forecast. That is, the *ex-ante* enrollment forecast is dominated by customers being defaulted onto E-TOU-C3. In order to reflect longer-term load impacts in the forecast, we use load impacts from the second summer of the Default TOU pilot. (Winter load impacts are only available for the first year.) As presented below, the use of second-year load impacts is conservative compared to using first-year load impacts.

[19] "Load Impact Evaluation of Pacific Gas and Electric Company's Residential Default Time-of-Use Pricing Pilot", Christensen Associates Energy Consulting, April 2019.

The Default TOU pilot employed eight segments defined by climate region, CARE status, CCA location, and NEM status. Table 4.14 shows the average peak-period load impact during summer months by segment, comparing the first- and second-year load impacts.

Table 4.14: Default E-TOU-C3 Pilot Non-holiday Weekday Peak-period Load Impacts, First vs. Second Summer

Segment	Peak-period Load Impact (kWh/hour/customer)	
	First Summer (Jun. – Sep. 2018)	Second Summer (Jun. – Sep. 2019)
Hot non-CARE	0.095 (5.2%)	0.049 (2.6%)
Moderate non-CARE	0.040 (4.6%)	0.017 (1.9%)
Moderate CARE	0.026 (3.2%)	0.005 (0.6%)
Cool non-CARE	0.009 (1.6%)	0.003 (0.5%)
Cool CARE	0.003 (0.5%)	-0.007 (-1.2%)
CCA = SCP	0.037 (4.8%)	0.032 (3.6%)
CCA= MCE	0.029 (3.6%)	0.015 (1.6%)
PG&E NEM	0.095 (5.6%)	0.120 (6.5%)
All	**0.038 (4.0%)**	**0.018 (1.8%)**

Table 4.15 shows the peak-period percentage load impacts that are used in the *ex-ante* forecast.[20] They are developed by re-weighting the summer 2019 and winter 2018-19 *ex-post* load impacts to be representative of LCAs rather than analysis segments using methods described in Section 3.2.2.

[20] While the table summarizes peak-hour load impacts, the *ex-ante* forecast uses hour-specific impacts for non-holiday weekdays.

Table 4.15: Default E-TOU-C3 Pilot Summer and Winter Peak-period Percentage Load Impacts

Local Capacity Area	Peak-period Percentage Load Impact	
	Summer	Winter
Greater Bay Area	1.8%	1.2%
Greater Fresno	2.6%	1.3%
Humboldt	0.8%	0.1%
Kern	2.6%	1.3%
Northern Coast	2.0%	1.3%
Other	1.8%	0.7%
Sierra	2.5%	1.3%
Stockton	2.3%	1.3%

5. Extension *Ex-Post* Load Impact Study Findings

The previous (PY2018) load impact study examined residential customers who enrolled in a TOU rate during the 2018 program year (between October 1, 2017 and September 30, 2018).

In this study, we explore the persistence of the load impacts for the customers included in the PY2018 study. This involved updating the load data for the customers who continued to be enrolled in the TOU rate (and maintain non-NEM status). To facilitate the analysis, we included only customers whose matched control-group customer is still valid (*i.e.*, continuously enrolled in E-1 and non-NEM).

Table 5.1 compares the estimated peak-period load impacts by TOU rate and year on the TOU rate. In the table, the "TOU year 1 load impact" corresponds to the PY2018 load impact, while the "TOU year 2 load impact" is the PY2019 load impact. Note that the PY2018 load impacts shown in Table 5.1 do not match those reported in the PY2018 study because we restricted the sample to customers who continued to be enrolled in the TOU rate during PY2019, maintained non-NEM status, and still had a valid matched control-group customer.[21]

[21] The average load impact from June through September in the PY2018 evaluation was 0.037 kWh/hour/customer for E-TOU-A; 0.168 kWh/hour/customer for E-TOU-B; and 0.036 kWh/hour/customer for voluntary E-TOU-C3.

Table 5.1: Average Peak-Period Load Impact (June through September) by TOU Rate (kWh/hour/customer)

Result	E-TOU-A	E-TOU-B	E-TOU-C3 Voluntary
TOU year 1 load impact	0.036 (5.0%)	0.051 (2.9%)	0.061 (4.7%)
TOU year 2 load impact	0.019 (2.6%)	0.036 (2.0%)	0.008 (0.6%)
Yr 1 = Yr 2 p-value	0.00	0.00	0.00

In each case, the year 2 load impact is smaller than the year 1 load impact (with the difference statistically significant). These estimates point to the possibility that TOU load impacts go down after the initial year of adoption. Note that the summer of 2019 was somewhat warmer than the summer of 2018.

6. *Ex-Ante* Load Impacts

6.1 Overview and Enrollment Forecasts

Ex-ante load impacts were developed separately for three TOU rates: E-TOU-A, E-TOU-B, and E-TOU-C3, and for five categories of TOU customers, as follows:

- *E-TOU-B and C3 incremental*. These are customers who are assumed to newly enroll in the E-TOU-B and C3 rates in future years. (E-TOU-A is closed to new enrollment during the forecast timeframe, so there are no incremental customers on that rate.)
- *E-TOU-A, B, and C3 embedded*. These are customers who were enrolled in E-TOU-A, B, and C3 as of the current year, and are assumed to remain on the rate in the future.

As with all *ex-ante* studies, we develop four sets of results associated with distinct weather scenarios, which are distinguished by:

- 1-in-2 weather conditions versus 1-in-10 weather conditions; and
- Whether the peak conditions are determined using the utility's peak or the utility's load at the time of CAISO's peak.

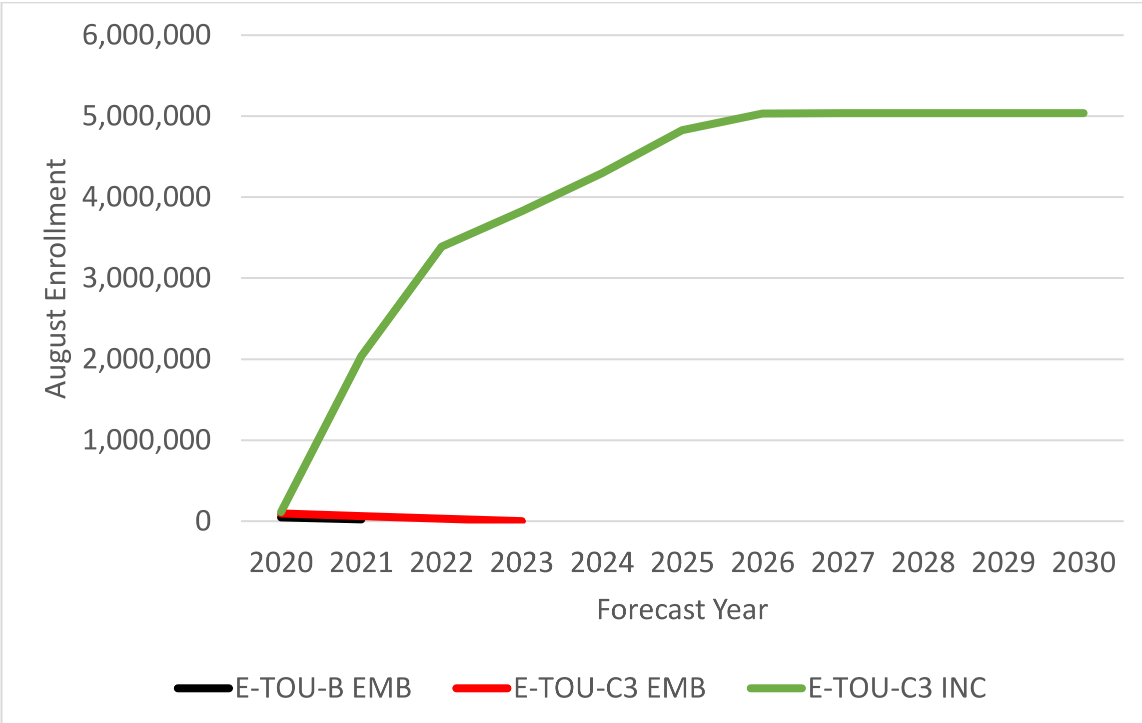
The weather conditions for each scenario were provided by PG&E.

Figure 6.1 shows the yearly enrollments forecast for the month of August[22], for each customer group. The forecast assumes that E-TOU-A will be terminated in June 2020, with the assumption that the majority of its customers will transition to E-TOU-C3. Enrollments for the E-TOU-C3 incremental group dominates the forecast due to the

[22] August is referenced here because it is likely to be the CAISO/PG&E peak period in a given year.

defaulting process in the initial forecast years. Note that the E-TOU-C3 embedded customers reflect those enrolled in the rate via the Default Transition Phase I and those who chose to voluntarily enroll in the rate prior to 2020.

Figure 6.1: Forecast August Enrollments by Year and Customer Group



6.2 Ex-Ante Load Impact Results

Ex-ante load impacts are developed for five groups of customers:

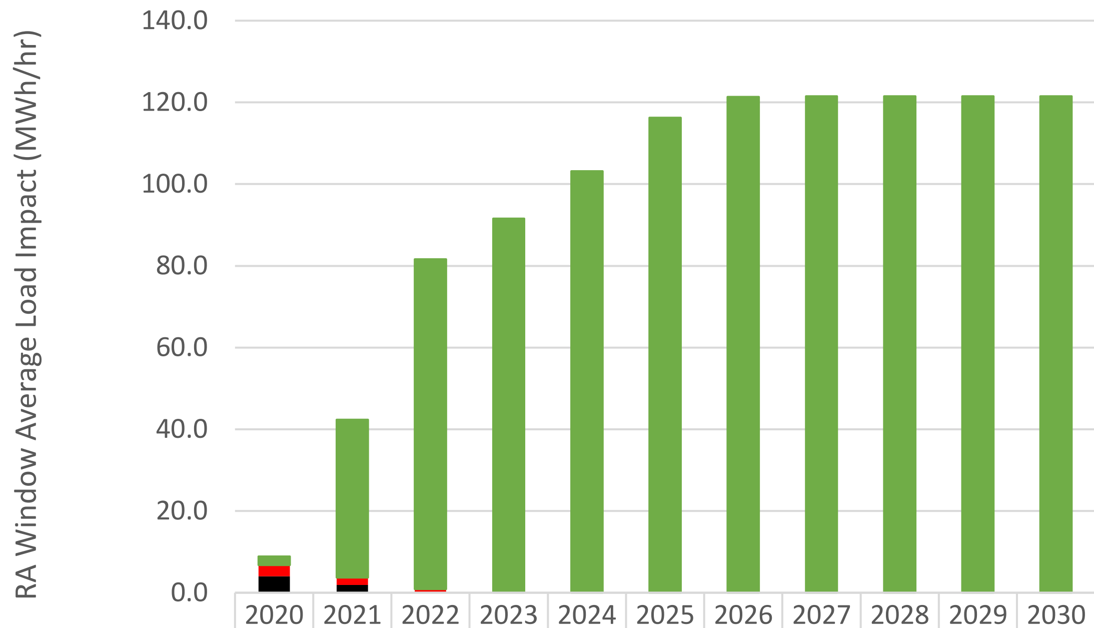
- E-TOU-A embedded;
- E-TOU-B incremental;
- E-TOU-B embedded.
- E-TOU-C3 incremental; and
- E-TOU-C3 embedded.

The following sub-sections present the *ex-ante* forecasts for each of these groups. For E-TOU-B, the incremental and embedded forecasts are combined into one sub-section.[23]

[23] The forecasts are combined because the basis of each forecast is the same. That is, the embedded and incremental *ex-ante* forecasts are based on the same per-customer reference loads and load impacts within E-TOU-B. The forecast are developed as extensions of the corresponding *ex-post* incremental load impact studies, which provide the best available estimates of E-TOU-B load impacts.

Figure 6.2 summarizes the forecast load impacts for each August during the forecast period. The values are the average load impacts during the Resource Adequacy window (4:00 to 9:00 p.m.) for the PG&E 1-in-2 weather conditions. The load impact pattern across years closely resembles the corresponding enrollment pattern, as shown in Figure 6.1.

Figure 6.2: Average RA Window Load Impacts by Year, *August PG&E 1-in-2 Peak Month*



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
E-TOU-C3 INC	2.1	38.7	80.7	91.5	103.2	116.3	121.4	121.5	121.5	121.5	121.5
E-TOU-C3 EMB	2.7	1.8	0.9	0.0							
E-TOU-B EMB	4.0	1.9									

6.2.1 *Ex-ante* load impacts for E-TOU-A embedded customers

Table 6.1 shows the E-TOU-A embedded load impacts, averaged during the Resource Adequacy window. The tables show monthly load impacts in 2020 associated with each of the four weather scenarios. The rate is terminated in June 2020, which explains the absence of load impacts for the second half of the year.

Table 6.1: E-TOU-A Embedded *Ex-Ante* Load Impacts, 2020 Monthly Peak Day during RA Window (MWh/hr)

Month	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	2.0	1.9	2.0	1.9
February	1.7	1.8	1.8	1.8
March	1.3	1.6	1.6	1.6
April	1.1	1.1	1.1	1.1
May	1.5	1.4	1.7	1.4
June	0.4	0.4	0.5	0.4
July	n/a	n/a	n/a	n/a
August	n/a	n/a	n/a	n/a
September	n/a	n/a	n/a	n/a
October	n/a	n/a	n/a	n/a
November	n/a	n/a	n/a	n/a
December	n/a	n/a	n/a	n/a

Figure 6.3 shows the hourly loads and load impacts associated with the January PG&E 1-in-2 scenario. The load impacts are concentrated in the peak hours, as one would expect.

Figure 6.3: E-TOU-A Embedded *Ex-Ante* Load Impacts, 2020 January PG&E 1-in-2 Peak Day

6.2.2 *Ex-ante* load impacts for E-TOU-B embedded and incremental customers

Tables 6.2 and 6.3 show the E-TOU-B embedded and incremental load impacts (respectively), averaged during the Resource Adequacy window. The tables show monthly load impacts in 2020 associated with each of the four weather scenarios. E-TOU-B is closed to new enrollment after April 2020. Embedded enrollment declines somewhat across the twelve months shown, from approximately 61,000 to 39,000 customers.

Table 6.2: E-TOU-B Embedded *Ex-Ante* Load Impacts, 2020 Monthly Peak Day during RA Window (MWh/hr)

Month	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	5.5	5.4	5.6	5.4
February	4.9	5.0	5.1	5.0
March	4.1	4.6	4.6	4.7
April	4.5	3.9	4.6	3.9
May	5.3	4.7	6.1	4.8
June	4.3	4.3	4.8	4.3
July	4.7	4.2	4.9	4.4
August	4.2	3.7	4.4	4.0
September	3.5	3.3	3.8	3.7
October	4.0	3.5	4.3	3.5
November	2.8	2.9	3.0	3.1
December	3.5	3.3	3.6	3.4

Table 6.3: E-TOU-B Incremental *Ex-Ante* Load Impacts, 2020 Monthly Peak Day during RA Window (MWh/hr)

Month	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	0.1	0.1	0.1	0.1
February	0.2	0.2	0.3	0.2
March	0.4	0.4	0.4	0.4
April	0.6	0.5	0.6	0.5
May	n/a	n/a	n/a	n/a
June	n/a	n/a	n/a	n/a
July	n/a	n/a	n/a	n/a
August	n/a	n/a	n/a	n/a
September	n/a	n/a	n/a	n/a
October	n/a	n/a	n/a	n/a
November	n/a	n/a	n/a	n/a
December	n/a	n/a	n/a	n/a

Figures 6.4 and 6.5 show the hourly loads and load impacts associated with two of the cells in Tables 6.2 and 6.3: the August and January PG&E 1-in-2 scenarios. Both figures show some evidence of shifting usage between TOU pricing periods (*i.e.*, decreases in peak-period usage and increases in usage in off-peak period usage).

Figure 6.4: E-TOU-B Embedded *Ex-Ante* Load Impacts, 2020 August PG&E 1-in-2 Peak Day

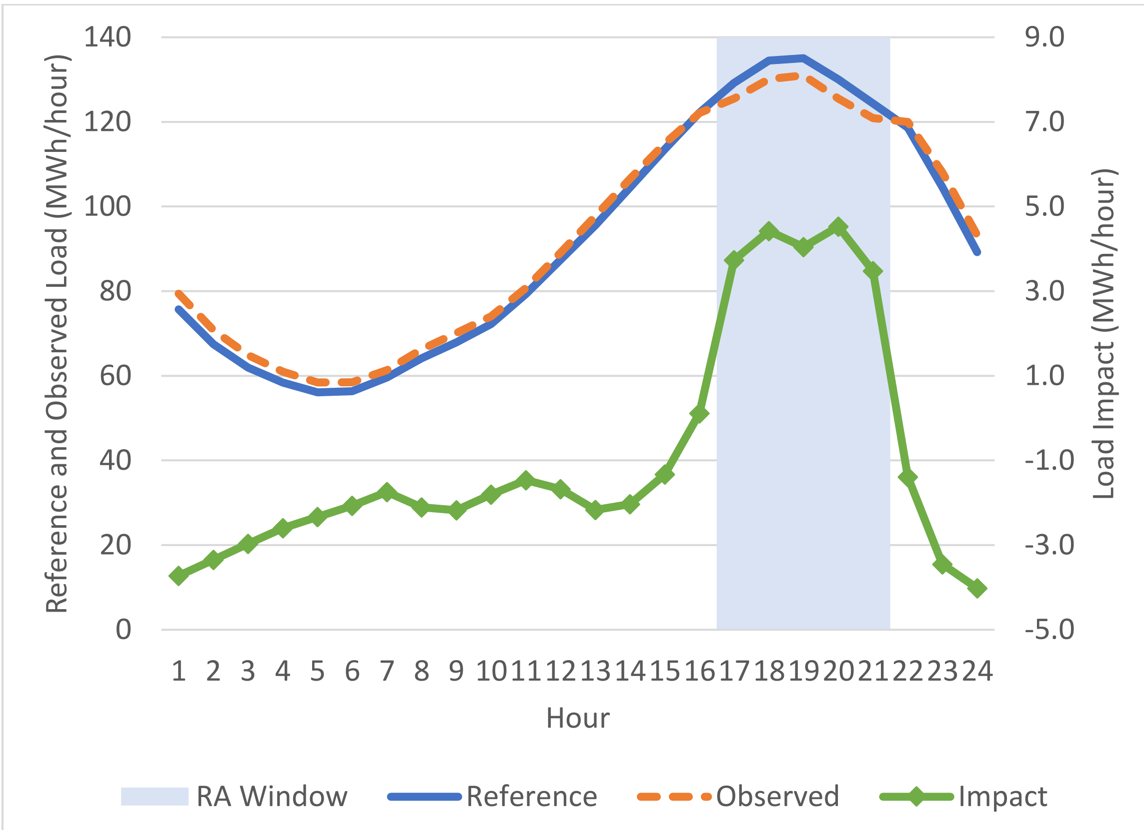
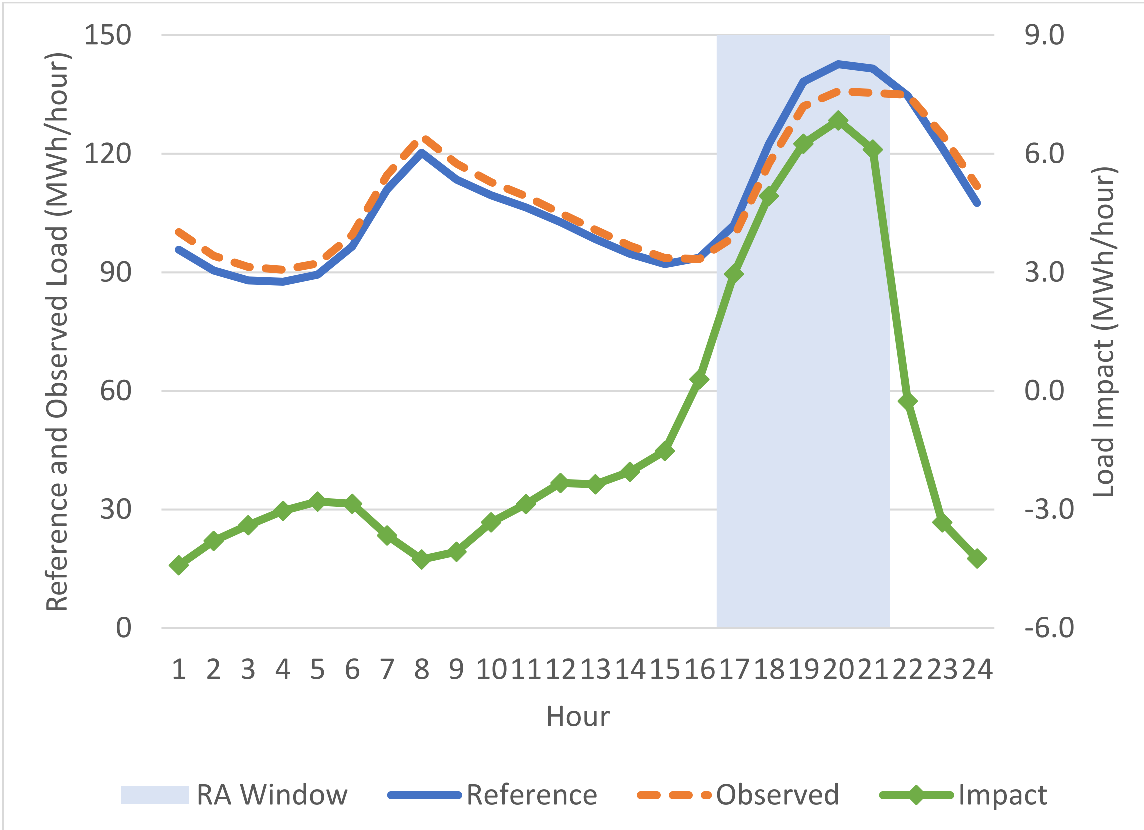


Figure 6.5: E-TOU-B Embedded *Ex-Ante* Load Impacts, 2020 January PG&E 1-in-2 Peak Day



6.2.3 *Ex-ante* load impacts for E-TOU-C3 embedded and incremental customers

Tables 6.4 and 6.5 show the E-TOU-C3 embedded and incremental load impacts (respectively), averaged during the Resource Adequacy window. The tables show monthly load impacts in 2020 associated with each of the four weather scenarios. Embedded enrollment declines slightly across the twelve months shown, from approximately 114,000 to 85,000 customers. In contrast, incremental enrollment increases from approximately 26,000 to 709,000 customers. This increase is due to customer migrations from E-TOU-A and E-TOU-B as well as the initial default waves.

Table 6.4: E-TOU-C3 Embedded *Ex-Ante* Load Impacts, 2020 Monthly Peak Day during RA Window (MWh/hr)

Month	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	1.2	1.2	1.2	1.2
February	1.1	1.1	1.1	1.1
March	0.9	1.0	1.0	1.0
April	0.8	0.8	0.8	0.8
May	1.3	1.1	1.5	1.1
June	2.9	2.8	3.2	2.9
July	3.2	2.8	3.3	2.9
August	2.8	2.4	3.0	2.7
September	2.4	2.2	2.6	2.5
October	1.1	0.9	1.2	0.9
November	0.7	0.7	0.7	0.8
December	0.9	0.9	0.9	0.9

Table 6.5: E-TOU-C3 Incremental *Ex-Ante* Load Impacts, 2020 Monthly Peak Day during RA Window (MWh/hr)

Month	CAISO 1-in-10	CAISO 1-in-2	PG&E 1-in-10	PG&E 1-in-2
January	0.3	0.3	0.3	0.3
February	0.3	0.3	0.3	0.3
March	0.3	0.3	0.3	0.3
April	0.3	0.3	0.3	0.3
May	1.1	1.0	1.3	1.0
June	1.6	1.6	1.8	1.6
July	2.3	2.0	2.4	2.1
August	2.2	1.9	2.4	2.1
September	2.0	1.9	2.2	2.1
October	5.9	5.5	7.0	5.3
November	6.4	6.6	6.9	7.3
December	8.8	8.2	9.1	8.5

Figures 6.6 and 6.7 show the hourly loads and load impacts associated with two of the cells in Table 6.5: the August and January PG&E 1-in-2 scenarios. Figure 6.6 shows summer TOU demand response, with increases in off-peak usage and decreases in peak-period usage. Figure 6.7 shows that winter load impacts are quite low in all hours.

Figure 6.6: E-TOU-C3 Incremental *Ex-Ante* Load Impacts, 2020 August PG&E 1-in-2 Peak Day

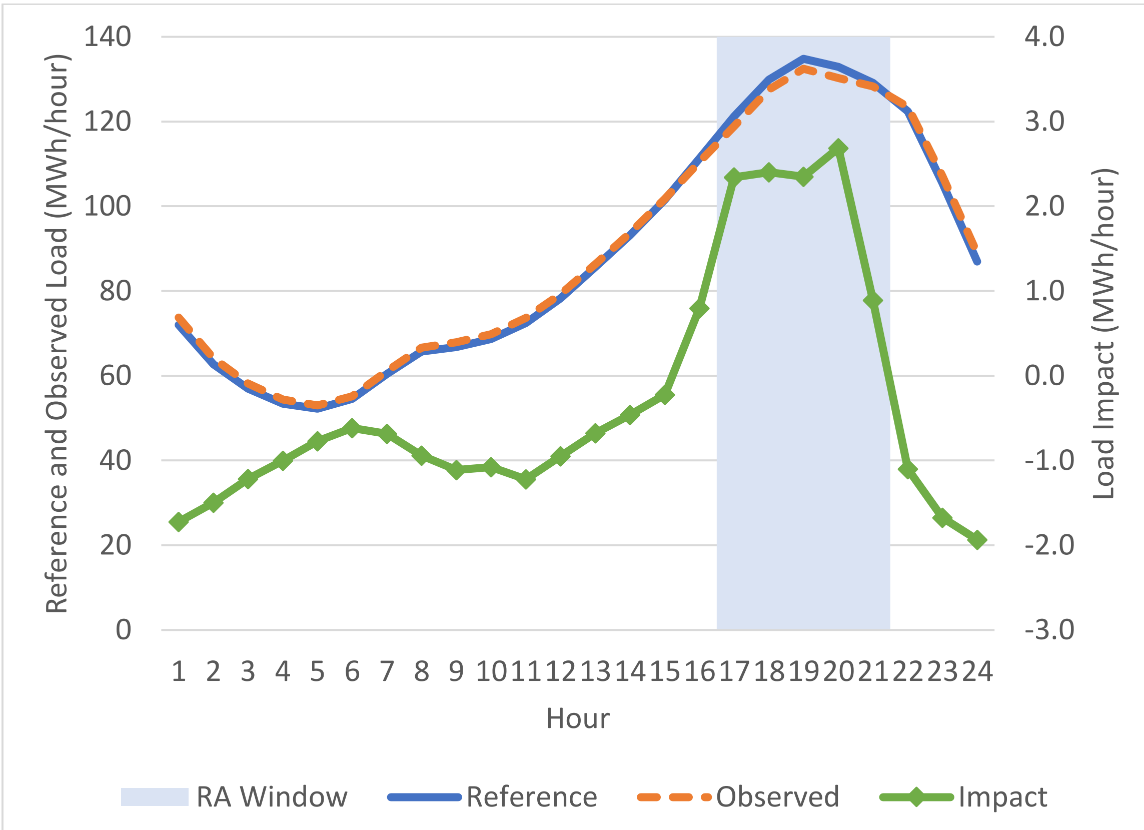
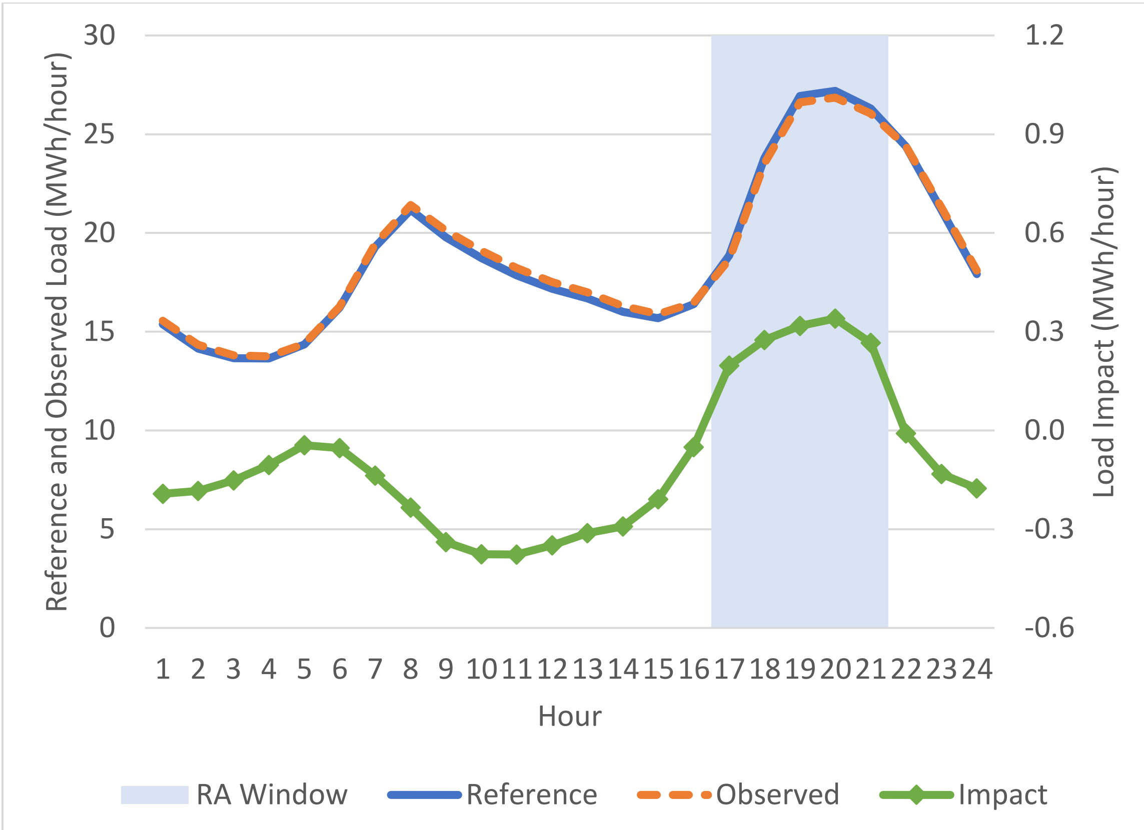


Figure 6.7: E-TOU-C3 Incremental *Ex-Ante* Load Impacts, 2020 January PG&E 1-in-2 Peak Day



7. Comparisons of Results

In a continuing effort to clarify the relationships between *ex-post* and *ex-ante* results, this section compares several sets of estimated load impacts, including the following:

- *Ex-post* load impacts from the current and previous studies;
- *Ex-ante* load impacts from the current and previous studies;
- Current *ex-post* and previous *ex-ante* load impacts; and
- Current *ex-post* and *ex-ante* load impacts.

The term “current” refers to the present study, which includes *ex-post* and *ex-ante* results for PY2019. The term “previous” refers to findings in report for PY2018. In the final comparison above, we illustrate the linkage between the PY2019 *ex-post* load impacts and the *ex-ante* forecast (of the 1-in-2 August peak day) for 2020. While the study includes E-TOU-A, E-TOU-B, and E-TOU-C3, we focus on the E-TOU-C3 forecast. This is because E-TOU-A will be terminated in June 2020 and E-TOU-B will be closed to new enrollments in 2020 and terminated in 2022. We further focus our comparisons on the *incremental* load impacts forecast of E-TOU-C3 customers in August 2022, after the defaulting process is forecast to be complete.[24]

7.1 Previous versus current ex-post incremental E-TOU-C3 load impacts

Table 7.1 shows the average peak-hour reference loads and load impacts for the August average weekday during the current and previous program years. In both cases, the load impacts represent customers who voluntarily enrolled in E-TOU-C3 rather than being defaulted onto the rate. (In contrast, the E-TOU-C3 *ex-ante* forecast is based on load impacts for defaulted customers.) The enrollment numbers are quite different across years, which affects the scale of the reference load and load impact. On a per-customer basis, load impacts are somewhat lower in the current evaluation. This is likely due to differences in customer composition, as temperatures were hotter August 2019 versus August 2018. It is useful to note that the two evaluations contain a completely different set of customers, as each evaluation estimates load impacts for the newly enrolled customers during that program year. Hence, in addition to the load impact percentages being driven by differences in temperature conditions across the time periods, there could be differences in customer characteristics (observable and unobservable) that affect demand response.

Table 7.1: Comparison of Average August Weekday Peak-period *Ex-Post* Impacts in PY2018 and PY2019, E-TOU-C3

Level	Outcome	PY2018	PY2019
Total	# SAIDs	1,554	15,818
	Reference (MW)	2.41	26.91
	Load Impact (MW)	0.22	1.67
	Avg. Temp.	79.6	86.4
Per SAID	Reference (kW)	1.55	1.70
	Load Impact (kW)	0.14	0.11
	% Load Impact	8.9%	6.2%

7.2 Previous versus current ex-ante incremental E-TOU-C3 load impacts

In this sub-section, we compare the *ex-ante* forecast prepared following PY2018 (the "previous study") to the *ex-ante* forecast contained in this study (the "current study").

[24] Note that the per-customer load impacts for embedded and incremental E-TOU-C3 load impacts are the same within an LCA, as both are based on the Default TOU pilot estimates. The incremental E-TOU-C3 forecast includes some customer migrations from E-TOU-A, E-TOU-B, and E-6 (who are assumed to match the Default E-TOU-C3 customers), but the effect of those migrations is overwhelmed by the scale of the default process by 2022.

There are several differences between these forecasts. In the previous evaluation, forecast enrollments did not reflect the defaulting of customers onto E-TOU-C3. In that evaluation, the majority of incremental E-TOU-C3 customers were migrated from E-TOU-A. Because of this (and because no winter E-TOU-C3 load impacts were available at the time), the E-TOU-C3 incremental *ex-ante* forecast was based on the *ex-post* impacts of E-TOU-A customers.

In contrast, the current evaluation reflects defaulted customers in its enrollments and the per-customer reference loads and load impacts are primarily taken from the Default TOU pilot evaluation. (Load impacts from customers migrated from E-TOU-A and E-TOU-B are based on the results of those evaluations.)

Table 7.2 reports the incremental load impact forecast for the August 2022 average weekday under PG&E 1-in-2 peak weather conditions. As noted earlier, the enrollment level is much higher in the current evaluation. The per-customer load impacts are lower in the current study, reflecting the findings from the second summer of the Default TOU pilot.

Table 7.2: Comparison of Average August 2022 Weekday Peak-period *Ex-Ante* Impacts in PY2018 and PY2019 Studies, E-TOU-C3

Level	Outcome	Previous Study	Current Study
Total	# SAIDs	89,983	3,389,280
	Reference (MW)	92.0	3,163
	Load Impact (MW)	3.7	61.7
	Avg. Temp.	80.7	77.2
Per SAID	Reference (kW)	1.02	0.93
	Load Impact (kW)	0.04	0.02
	% Load Impact	4.0%	2.0%

7.3 Previous ex-ante versus current ex-post incremental E-TOU-C3 load impacts

Table 7.3 provides a comparison of the *ex-ante* forecast of August 2019 average weekday load impacts prepared following PY2018 and the *ex-post* PY2019 load impacts estimated as part of this study. The *ex-ante* forecast shown in the table represents the August average weekday during a PG&E 1-in-2 weather year. Considerably more customers voluntarily enrolled in E-TOU-C3 than was forecast in the PY2018 evaluation. In addition, the reference loads and load impacts were higher than forecast. The higher reference loads are expected, given that the previous *ex-ante* forecast was based on E-TOU-A customers, who tend to have lower usage because of the design of the rate. (It includes a baseline credit while E-TOU-B does not; thus E-TOU-B tends to attract higher use customers while E-TOU-A attracts lower-use customers.)

Table 7.3 Comparison of Previous *Ex-Ante* and Current *Ex-Post* Impacts, E-TOU-C3

Level	Outcome	*Ex-Ante* for Aug. 2019 Avg. Weekday from PY2018 Study	*Ex-Post* for Aug. 2019 Avg. Weekday from PY2019 Study
Total	# SAIDs	6,772	15,818
	Reference (MW)	8.0	26.91
	Load Impact (MW)	0.3	1.67
	Avg. Temp.	82.4	86.4
Per SAID	Reference (kW)	1.19	1.70
	Load Impact (kW)	0.05	0.11
	% Load Impact	4.0%	6.2%

7.4 Current ex-post versus current ex-ante incremental E-TOU-C3 load impacts

Table 7.4 compares the PY2019 *ex-post* load impacts for the August average weekday to the corresponding *ex-ante* forecast for 2020 produced in this study. This is another apples-to-oranges comparison. The *ex-post* impacts relate to customers who voluntarily enrolled in E-TOU-C3. In contrast, the *ex-ante* forecast is a blend of three customer types: 55 percent E-TOU-A customers; 6 percent E-TOU-B customers; and 39 percent Default E-TOU-C3 customers. This E-TOU-A dominated mix results in a low reference load and load impact for the incremental E-TOU-C3 forecast in August 2020.

Table 7.4 Comparison of Current *Ex-Post* and *Ex-Ante* Load Impacts, E-TOU-C3

Level	Outcome	*Ex-Post* for Aug. 2019 Avg. Weekday from PY2019 Study	*Ex-Ante* for Aug. 2020 Avg. Weekday from PY2019 Study
Total	# SAIDs	15,818	113,782
	Reference (MW)	26.91	105.1
	Load Impact (MW)	1.67	1.7
	Avg. Temp.	86.4	78.5
Per SAID	Reference (kW)	1.70	0.92
	Load Impact (kW)	0.11	0.01
	% Load Impact	6.2%	1.6%

Table 7.5 reviews the potential sources of differences between PY2019 *ex-post* August average weekday load impacts and the corresponding *ex-ante* load impacts. The most significant difference is in the enrollments that scale the per-customer *ex-ante* load impacts to the program level.

Table 7.5: E-TOU-A Incremental *Ex-Post* versus *Ex-Ante* Factors

Factor	*Ex-Post*	*Ex-Ante*	Expected Impact
Weather	86.4 degrees Fahrenheit during the peak period window of the August 2019 average weekday.	78.5 degrees Fahrenheit during the peak period on utility-specific 1-in-2 August average weekday.	Milder *ex-ante* weather decreases the reference load and load impact slightly. The temperature difference partly reflects a difference in customer mix, with relatively more Greater Bay Area customers in the *ex-ante* forecast.
Enrollment	15,818 SAIDs during the August 2019 average weekday.	113,782 SAIDs in August 2020.	The enrollment level directly scales the per-customer *ex-ante* load impacts. The *ex-ante* forecast reflects the migration of E-TOU-A customers to the E-TOU-C3.
Methodology	LCA-specific difference-in-differences estimates using voluntary E-TOU-C3 adopters and a matched control group.	Estimated using season-specific models that assume a constant percentage load impact across LCAs and months. Combined forecasts across E-TOU-A, E-TOU-B, and E-TOU-C3 forecasts to reflect terminated rates over time.	Differences in the reference and load impact levels.

Appendices

Appendix A E-1 to E-TOU-A *Ex-Post* Load Impact Tables:

2a. PGE_2019_Res_TOU_E1_to_ETOUA_Ex_Post_PUBLIC.xlsx

Appendix B E-1 to E-TOU-B *Ex-Post* Load Impact Tables:

2b. PGE_2019_Res_TOU_E1_to_ETOUB_Ex_Post_PUBLIC.xlsx

Appendix C E-1 to E-TOU-C3 (Voluntary) *Ex-Post* Load Impact Tables:

2c. PGE_2019_Res_TOU_E1_to_ETOUC_Ex_Post_PUBLIC.xlsx

Appendix D E-TOU-A Embedded *Ex-Ante* Load Impact Tables:

2d. PGE_2019_Res_TOU_ETOUA_Embedded_Ex_Ante_PUBLIC.xlsx

Appendix E E-TOU-B Embedded *Ex-Ante* Load Impact Tables:

2e. PGE_2019_Res_TOU_ETOUB_Embedded_Ex_Ante_PUBLIC.xlsx

Appendix F E-TOU-C3 Embedded *Ex-Ante* Load Impact Tables:

2f. PGE_2019_Res_TOU_ETOUC_Embedded_Ex_Ante_PUBLIC.xlsx

Appendix G E-TOU-B Incremental *Ex-Ante* Load Impact Tables:

2g. PGE_2019_Res_TOU_ETOUB_Incremental_Ex_Ante_PUBLIC.xlsx

Appendix H E-TOU-C3 Incremental *Ex-Ante* Load Impact Tables:

2h. PGE_2019_Res_TOU_ETOUC_Incremental_Ex_Ante_PUBLIC.xlsx

Appendix I *Ex-Post* Analysis Match Quality

Appendix I. Match Quality

This appendix presents the summaries of our control-group matching process. Figures I.1 through I.6 illustrate the seasonal matches for E-TOU-A, E-TOU-B, and E-TOU-C3 voluntary customers. Each figure contains the average hourly profiles for the treatment and matched control-group customers by day type (high and mild days). The figures aggregate results across LCAs and CARE status, thus reflecting a rate-level match quality. The match quality for each matching sub-group is summarized in Tables I.1 through I.6.

Figure I.1: E-TOU-A Summer Match Quality

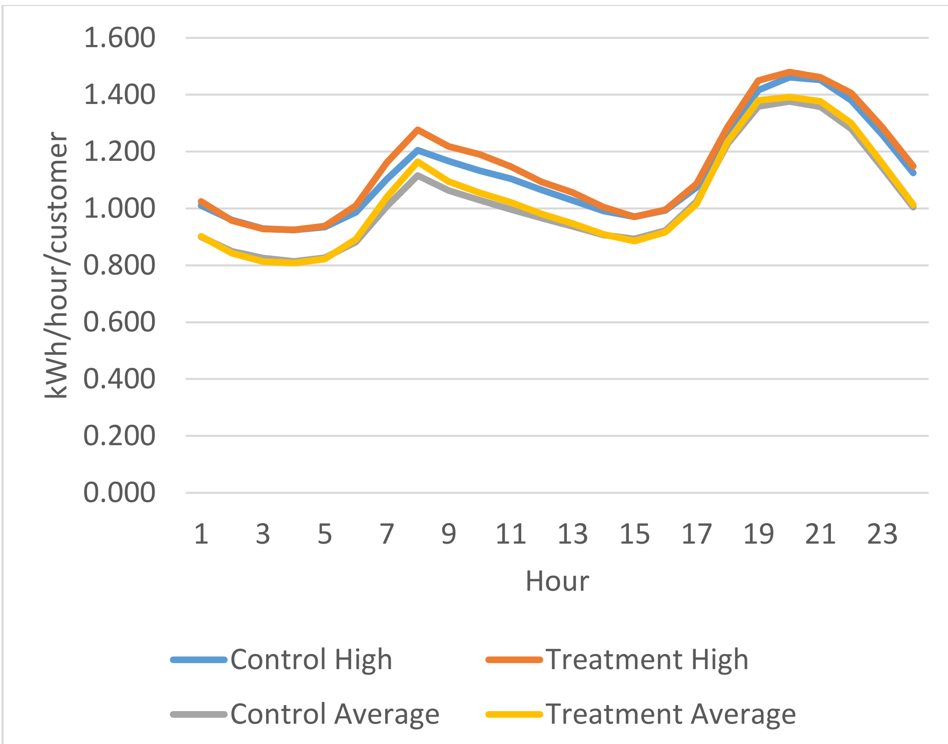


Figure I.2: E-TOU-A Winter Match Quality

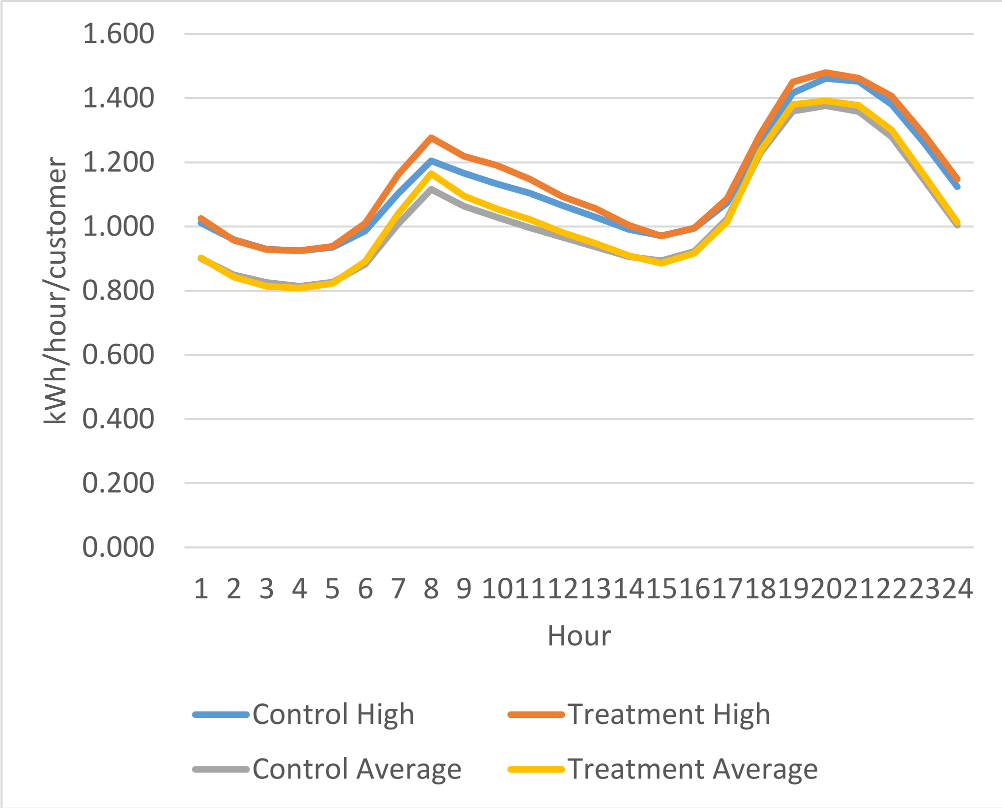


Figure I.3: E-TOU-B Summer Match Quality

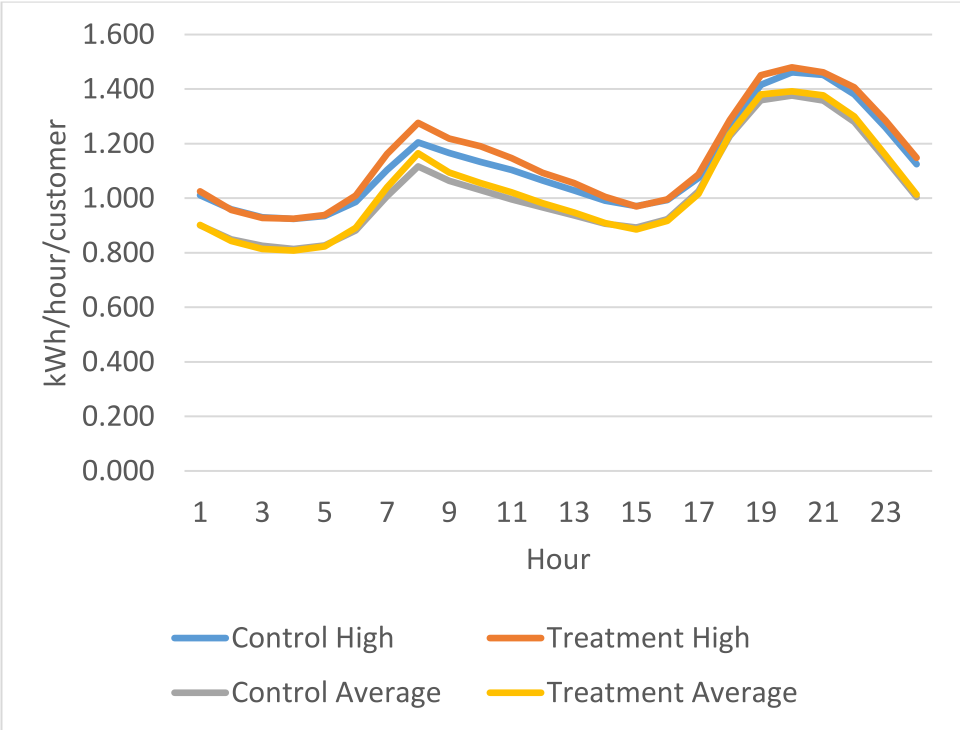


Figure I.4: E-TOU-B Winter Match Quality

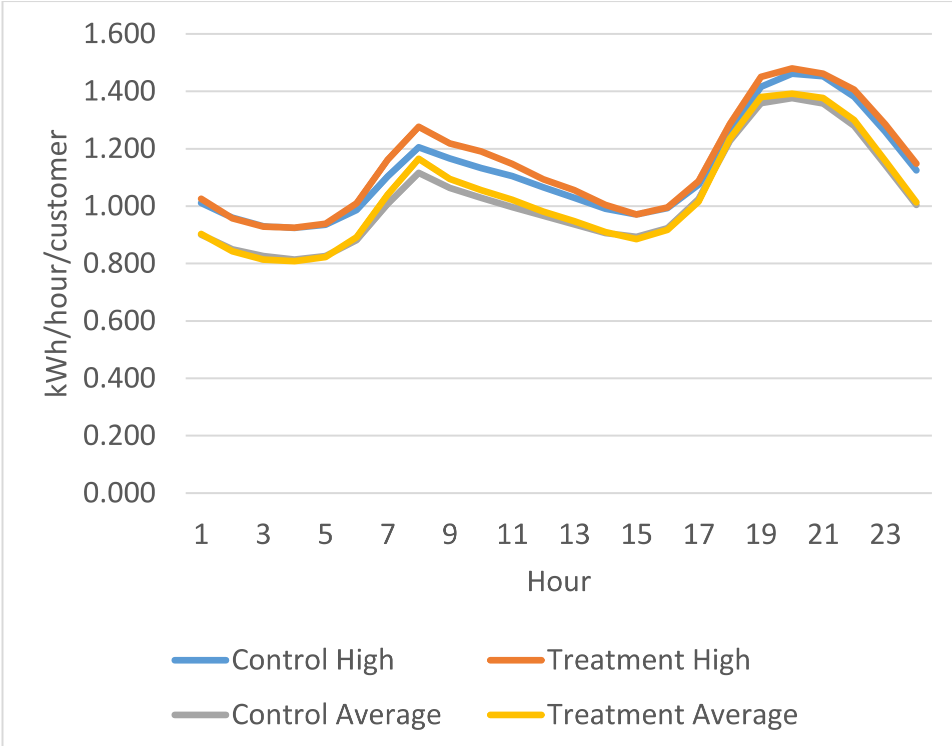


Figure I.5: E-TOU-C3 Voluntary Summer Match Quality

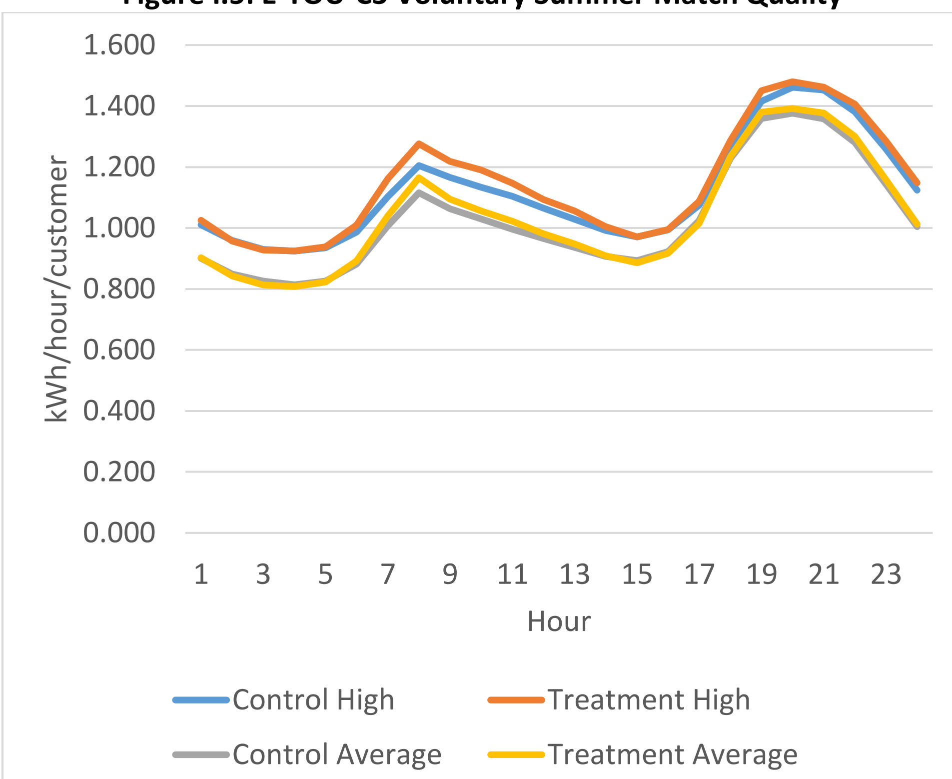
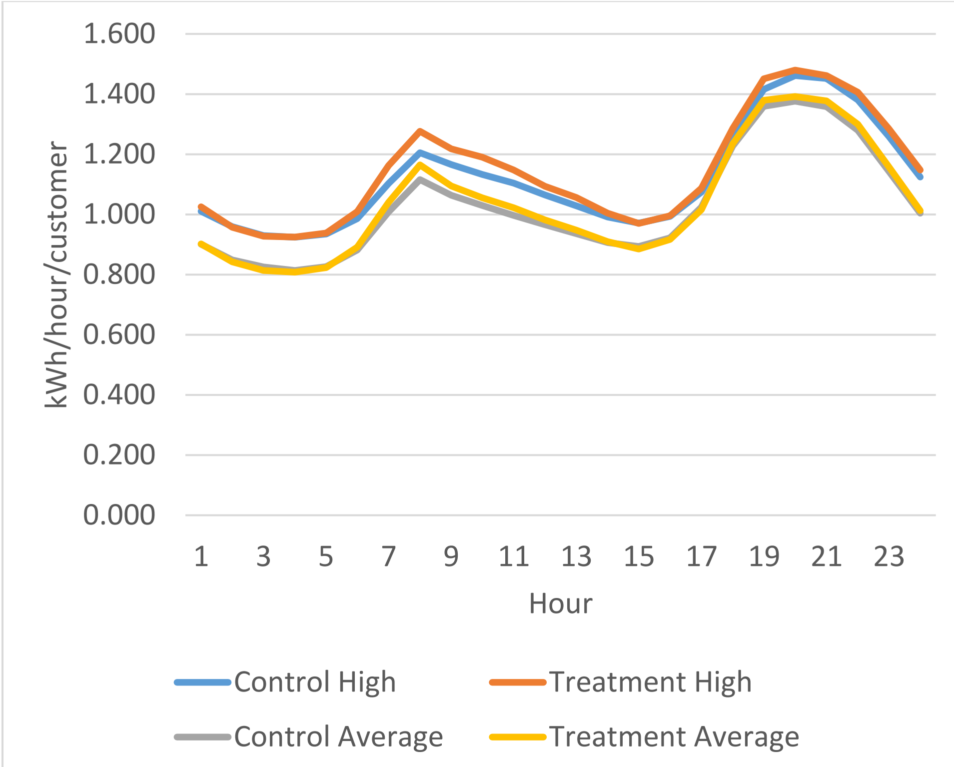


Figure I.6: E-TOU-C3 Voluntary Winter Match Quality



Tables I.1 through I.6 show the mean percentage error (MPE) and mean absolute percentage error (MAPE) calculated across the two 24-hour load profiles at the "cell" level by season, where a cell is defined as a combination of LCA and CARE status. MPE provides an indicator of bias in the matches, while MAPE provides a measure of accuracy. The poor matches are restricted to cells with few customers, as one would expect.

Table I.1: Summer Match Quality, E-TOU-A

LCA	Non-CARE			CARE		
	MPE	MAPE	N	MPE	MAPE	N
Greater Bay Area	0.6%	1.9%	3,767	0.7%	2.3%	752
Greater Fresno	-0.7%	5.6%	44	-0.4%	3.4%	58
Humboldt	-2.3%	5.2%	72	0.7%	5.1%	50
Kern	13.4%	28.2%	4	1.5%	9.9%	14
Northern Coast	-0.6%	2.8%	296	0.1%	3.9%	97
Other	-0.2%	2.8%	173	0.6%	3.4%	124
Sierra	-0.1%	5.1%	135	-1.7%	4.9%	80
Stockton	-1.6%	7.7%	31	3.6%	7.8%	34

Table I.2: Winter Match Quality, E-TOU-A

LCA	Non-CARE			CARE		
	MPE	MAPE	N	MPE	MAPE	N
Greater Bay Area	-0.1%	2.3%	3,767	-0.5%	2.8%	752
Greater Fresno	-1.0%	6.2%	44	-2.6%	4.5%	58
Humboldt	1.5%	5.1%	72	0.6%	6.4%	50
Kern	14.5%	24.4%	4	-1.1%	8.2%	14
Northern Coast	0.6%	2.6%	296	-0.9%	3.6%	97
Other	0.5%	3.2%	173	0.4%	4.1%	124
Sierra	-0.6%	4.7%	135	0.4%	4.2%	80
Stockton	-3.2%	7.1%	31	-4.0%	9.6%	34

Table I.3: Summer Match Quality, E-TOU-B

LCA	Non-CARE			CARE		
	MPE	MAPE	N	MPE	MAPE	N
Greater Bay Area	-1.1%	1.2%	2,863	-1.2%	1.6%	779
Greater Fresno	-2.7%	4.5%	91	-0.7%	1.4%	216
Humboldt	-2.0%	4.7%	173	-3.0%	4.5%	90
Kern	-2.2%	5.8%	27	-1.0%	1.9%	48
Northern Coast	-1.6%	2.4%	433	-3.8%	4.8%	95
Other	-1.3%	3.8%	215	-1.9%	3.0%	234
Sierra	-2.8%	3.4%	192	-1.8%	2.4%	163
Stockton	-5.2%	6.8%	63	-1.9%	2.4%	75

Table I.4: Winter Match Quality, E-TOU-B

LCA	Non-CARE			CARE		
	MPE	MAPE	N	MPE	MAPE	N
Greater Bay Area	-1.0%	1.6%	2,863	-1.6%	1.9%	779
Greater Fresno	-3.3%	4.2%	91	-1.3%	2.0%	216
Humboldt	-1.3%	3.6%	173	-2.4%	4.2%	90
Kern	-1.2%	7.1%	27	-0.5%	2.9%	48
Northern Coast	-0.9%	1.8%	433	0.4%	3.7%	95
Other	-2.1%	2.8%	215	-1.1%	2.1%	234
Sierra	-1.9%	2.4%	192	-1.0%	2.4%	163
Stockton	-1.0%	4.1%	63	-1.4%	2.7%	75

Table I.5: Summer Match Quality, E-TOU-C3 Voluntary

LCA	Non-CARE			CARE		
	MPE	MAPE	N	MPE	MAPE	N
Greater Bay Area	-1.5%	2.0%	874	0.3%	2.4%	330
Greater Fresno	-2.0%	3.7%	36	1.3%	3.5%	74
Humboldt	-4.5%	7.3%	29	-1.2%	5.5%	32
Kern	7.0%	16.3%	2	-0.3%	2.7%	31
Northern Coast	-0.9%	2.3%	134	-2.6%	4.6%	40
Other	-2.5%	5.1%	93	0.9%	3.0%	112
Sierra	-0.2%	5.1%	68	-0.3%	3.1%	75
Stockton	-1.8%	9.0%	15	-1.8%	3.9%	35

Table I.6: Winter Match Quality, E-TOU-C3 Voluntary

LCA	Non-CARE			CARE		
	MPE	MAPE	N	MPE	MAPE	N
Greater Bay Area	-1.5%	1.8%	874	-1.0%	1.7%	330
Greater Fresno	1.1%	5.1%	36	-1.0%	4.2%	74
Humboldt	-3.8%	7.0%	29	1.9%	7.1%	32
Kern	20.4%	29.7%	2	-2.1%	4.7%	31
Northern Coast	-1.5%	3.1%	134	-3.1%	5.6%	40
Other	-1.3%	2.9%	93	-0.9%	3.4%	112
Sierra	-0.5%	5.3%	68	-0.2%	4.9%	75
Stockton	-9.6%	11.0%	15	-1.9%	6.3%	35